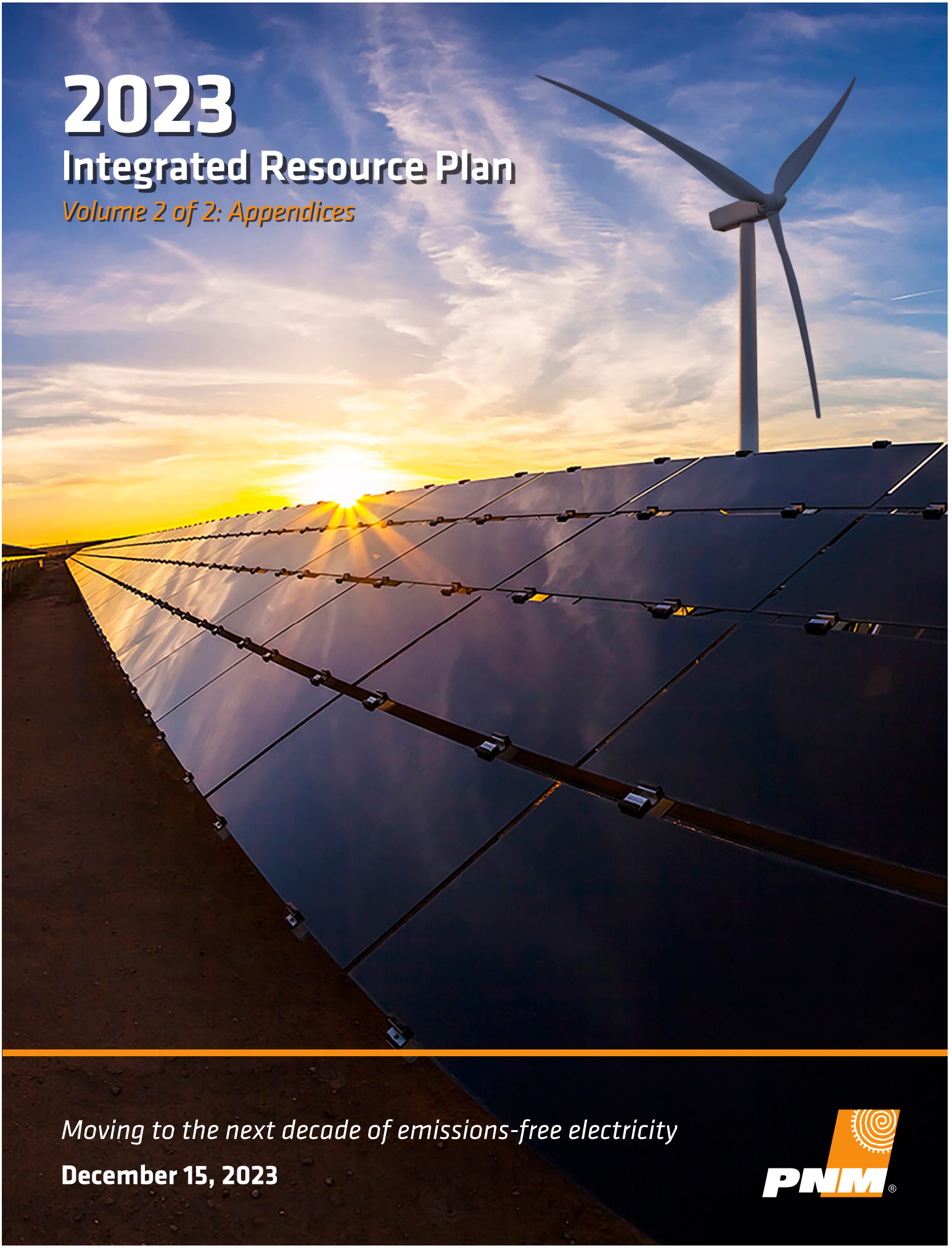


2023
Integrated Resource Plan
Volume 2 of 2: Appendices

Moving to the next decade of emissions-free electricity

December 15, 2023

PNM®

PNM 2023 INTEGRATED RESOURCE PLAN APPENDICES – VOLUME 2 OF 2

TABLE OF CONTENTS

Appendix O. Detailed Records of Facilitated Stakeholder Process O-1

<This page intentionally left blank>

Appendix O. Detailed Records of Facilitated Stakeholder Process

This appendix includes records of the public stakeholder processes that occurred during this IRP. Included in this appendix are:

- Meeting summaries, including questions and comments by stakeholders;
- Copies of presentations provided by PNM (prior to the facilitated stakeholder process); and
- Copies of presentations provided by GridWorks in the facilitated stakeholder process.

APPENDIX O STAKEHOLDER ENGAGEMENT MEETING SUMMARIES AND Q&A

Between April 2022 and October 2023, PNM and Gridworks invited stakeholders to contribute to the development of the 2023 Integrated Resource Plan (IRP). This appendix includes meeting summaries and questions and responses from:

1) PNM's Public Advisory Process
2) Gridworks Facilitated Stakeholder Process.

PNM's Public Advisory Process. On April 28, 2022, PNM launched the Public Advisory Process, which consisted of a series of technical presentations for stakeholders devoted to discussing the advantages and disadvantages of applying different methodologies in the modeling framework for the IRP. PNM staff and contractors conducted 13 virtual meetings, from May 2022 to March 2023, and hosted a Public Advisory Group Day on August 17, 2022, featuring a stakeholder presentation.

Gridworks Facilitated Stakeholder Process. On December 15, 2023, the New Mexico's Public Regulation Commission appointed Gridworks as the independent facilitator to lead a stakeholder process advising PNM on the development of two foundational elements of the IRP: the Statement of Need and the Action Plan. Gridworks launched the Facilitated Stakeholder Process on March 28, 2023, and led a series of eight virtual meetings and two in-person workshops featuring presentations by stakeholders and PNM staff.

Meeting summaries, presentations, and questions and responses can also be found on the PNM and Gridworks websites.

Table of Contents

MEETING SUMMARIES 4
PNM Public Advisory Process **5**
(April 28, 2022 - March 15, 2023) **5**
April 28, 2022: Kickoff Meeting 5
May 25, 2022 10
June 8, 2022: Technical Session #1 17
June 22, 2022, Technical Session #2 22
July 6, 2022, Technical Session #3 25
July 27, 2022, Technical Session #4 31
August 17, 2022, Public Advisory Group Day "Methods For Accounting For Correlated Outages And Derates Of Conventional Generators" 36
September 13, 2022, Technical Session #5 37
October 6, 2022, Technical Session #6 44
October 17, 2022, Technical Session #7 49
November 2, 2022, Technical Session #8 51
December 15, 2022, Technical Session #9 53
January 17, 2023, Technical Session #10 60
February 15, 2023, Technical Session #11 63
March 15, 2023, Technical Session #12 69
Gridworks Facilitated Stakeholder Process **73**
(March 28, 2023 - October 19, 2023) **73**
March 28, 2023 Meeting #1: Orientation for PNM Integrated Resource Plan 73
May 4, 2023 Meeting #2: PNM Integrated Resource Plan Stakeholder Workshop 77
May 18, 2023 Meeting #3 81
June 1, 2023 Meeting #4 83
June 15, 2023 Meeting #5 86
June 29, 2023 Meeting #6 89
July 27, 2023 Meeting #7 93
August 31, 2023 Meeting #8 96
September 28, 2023 Meeting #9 99
October 19, 2023 Meeting #10 102

QUESTIONS AND ANSWERS 105
PNM Public Advisory Process 106
(April 28, 2022 – March 15, 2023) 106
General 106
Grid Modernization 115
IRP Report 139
Load & Energy Efficiency Forecasting 145
Modeling 170
Reliability-Resilience-Resource Adequacy 297
Transmission 348
Gridworks Facilitated Stakeholder Process 400
(March 28, 2023 - October 19, 2023) 400
March 28, 2023 Meeting #1: Orientation for PNM Integrated Resource Plan 400
PNM Presentation May 11, 2023 410
May 18, 2023 Meeting #3 427
June 1, 2023 Meeting #4 434
June 15, 2023 Meeting #5 437
June 29, 2023 Meeting #6 450
July 27, 2023 Meeting #7 464
August 31, 2023 Meeting #8 475
September 28, 2023 Meeting #9 495
PNM Presentation October 6, 2023 502
October 19, 2023 Meeting #10 517

(Disclaimer: This Appendix is a work in progress. It uses the color scheme present in the 2023 PNM IRP and prioritizes matching the visual style of said IRP.)

MEETING SUMMARIES

PNM Public Advisory Process (April 28, 2022 - March 15, 2023)

April 28, 2022: Kickoff Meeting

On April 28, 2022, PNM kicked off its Public Advisory Process for its 2023 IRP (Integrated Resource Planning) filing. The session was a hybrid in-person and virtual meeting led by Director of Integrated Resource Planning Nick Phillips, who gave an update of PNM activities and current events, an overview of the IRP process, and a preview of upcoming stakeholder meetings. At the outset of the listening session, Mr. Phillips welcomed participants' input on the following:

1. What PNR did well in the last (2020) IRP and where can it improve

2. Ideas for technical discussions

3. The proper way to balance reliability, customer cost, and the accelerating transition to clean energy

4. Ways PNR can be more collaborative with its public stakeholders throughout the process

Discussion topics and comments covered, inter alia, customer-owned storage systems, planning for reliability and resource adequacy as decarbonization increases, the impact of any proposed changes on subpopulations, and planning for extreme weather events. (See below for the complete list.)

Mr. Phillips also introduced the two firms that will be assisting PNM with the IRP (Energy + Environmental Economics [(E3)] and Astrapé Consulting) and announced that E3 would present the findings of its Southwest Resource Adequacy Study at the next stakeholder meeting on May 25, 2022.

Meeting Attendees

A total of 43 stakeholders, not including PNM staff, attended the meeting, including members of the public and representatives from the following organizations: Coalition for Clean Affordable Energy (CCAE), Renewable Energy Industries Association of New Mexico (REIA), Sandia National Laboratories, and Western Resource Advocates (WRA).

Meeting slides can be found here.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
Member of the Public:	Will all meetings be available virtually?	**General**
REIA:	Why doesn't your list of current events include the interconnection docket 21- 00266?	**Transmission**
Member of the Public:	What do you mean when you say PNM is one of the top companies in the U.S. for diversity?	**General**
Member of the Public:	Can you provide a breakdown of the different resources on PNM's system over time as well as the peak loads over time?	**Load & Energy Efficiency Forecasting**
Member of the Public:	As we expand residential commercial batteries through power walls or charging automobiles, we need to be assured that those facilities have capabilities that maximize the utilities [available to the public], not the company. For instance, we could have greater reliability through some system that allowed PNM to utilize the capacity when it's not really needed by the resident, but there has to be some kind of relationship with manufacturers or some requirements that, if you have a power wall, it has to have at least these kinds of capabilities. Is anything like that	**Grid Mod**
	happening … and how do we make sure it's not an advertising gimmick for [electric] automobile manufacturers?	

CCAE:	As partner systems in southwestern states move to renewable or battery storage sources of energy, how may that affect the sales of energy to PNM? Or as regional utilities or regional load serving entities transition their systems towards more renewables and energy limited resources, will that impact PNM's ability to purchase energy on the wholesale market?	**Load & Energy Efficiency Forecasting**
CCAE:	Please clarify what you mean when you say, as the system moves toward more decarbonization technologies, PNM wants the system to act the same. It's my understanding that these newer technologies inherently require a system that acts differently, maybe more nimbly, and utilizes energy sources in a different way.	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	As you put more and more individual storage units into a gateway system that gets smarter and smarter, could you use artificial intelligence to program a group of gateways to manage the system on a real-time basis and not worry about taking from person A, B, or C? Artificial intelligence will do it fast.	**Grid Mod**
Member of the Public:	What sub-populations of the PNM customer base are going to be impacted and in what order? How do we keep that in balance, both for the system and as we have more distributed generation? How does that change the role of the grid and other factors?	**Load & Energy Efficiency Forecasting** **Grid Mod**

Member of the Public:	What other studies, in addition to the Southwest Resource Adequacy Study and the PNM Resiliency Study are underway now?	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	When do you plan to file the 18% planning reserve margin, if you have not already?	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	Will you do any kind of analysis regarding the contingency reserves rather than just the planning reserves?	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	If it turns out that sometime down the road it becomes obvious that the system needs to be more bi-directional, will you be looking into the costs associated with that?	**Grid Mod**
Member of the Public:	Please distinguish between load served and connected load and be consistent in the IRP.	**IRP Report**
Member of the Public:	Can the system be more robust in an extreme weather event?	**Reliability, Resilience & Resource Adequacy** **Grid Mod**
Member of the Public:	Do you look at the various "flavors" of hydrogen and the various implications of their creation in this process?	**Modeling**
Member of the Public:	Where is PNMR (PNM's holding company) in terms of public outreach with the IRP?	**General**

Sandia National Laboratories:	[The IRP process] could benefit from a technical session discussing retail rate design. What kind of rate designs would be enabled by AMI?	**Grid Mod**
WRA:	I hope that one of the sub-topics of transmission will be the work that's being done around the West for regional transmission coordination (RTOs). What's being considered, by whom, and where? Is this an opportunity for PNM? What I've been learning is that for reliability in this age of increasing weather variability and penetration of utility-scale renewables, we need a larger footprint, so I hope that's one of the sub-topics. Regarding historically marginalized communities, we may also want to consider the location of generation-- whether it is for the jobs that would be provided or such.	**Transmission**

May 25, 2022

On May 25, 2022, PNM held the first in a planned series of presentations devoted to discussing different technical methodologies within the 2023 IRP modeling framework. The session, which was virtual and in-person, focused on the presentation and discussion of the findings of a study by E3 (Energy + Environmental Economics), "Resource Adequacy in the Desert Southwest," and a collaboration by E3, Astrapé Consulting, and PNM, "Supply Resilience in Planning for PNM."

E3 modeled several scenarios designed to inform future resource planning, using data provided by PNM and utilities in Arizona. Key findings were:

- Load growth and resource retirements are creating an urgent need for new resources in the Southwest.
- Utilities' current resource plans have identified sufficient capacity additions to maintain reliability.
- A large share of the region's long-term needs will be met with solar, storage, and other "non-firm" resources.
- Even as solar and storage grow, the region's remaining firm resources will be needed for reliability.
- Substantial reliability risks remain as the region's electricity resource portfolio transitions.

PNM commissioned the second, resiliency, study to address the following:

- Questions from stakeholders participating in the 2020 IRP process surrounding extreme weather analysis and durations of energy storage included in 2020 IRP portfolios.
- The increased frequency of extreme weather events—the 2021 Texas event occurred two weeks after PNM filed the 2020 IRP.
- PNM's desire to gain a better understanding of risks associated with decarbonization and the move from firm, dispatchable resources to variable and energy limited resources.

Key takeaways from the study included:

- Portfolios planned with a reliability standard in mind vary in performance during extreme events.
- Stress testing candidate portfolios for resilience is important to understand differences in their performance.
- Winterization helps reduce outages and firm up generation, reducing the severity of extreme event impacts.
- During ice storms, broader southwest dynamics will have significant impact on PNM's ability to avoid outages under extreme events. PNM can weather localized ice storms by relying on external markets, but region-wide events almost certainly lead to outages. Market support is limited in summer; PNM's system can avoid outages during a heat wave unless load reaches 1-in-20 levels, or a significant level of generation is forced out.
- PNM should continue to monitor the risk profile in the winter season. Resource accreditation should continue to match the risk profile PNM is presented with.

- As PNM increases its storage portfolio, its operational limits and utilization should be understood and considered in resource adequacy modeling.

Meeting Attendees

A total of 40 stakeholders, not including PNM staff, attended the meeting, including members of the public and representatives from the following organizations: CSolPower, InterWest Energy Alliance, Office of the New Mexico Attorney General, Pine Gate Renewables, and the New Mexico Renewable Energy Transmission Authority (RETA).

Meeting slides can be found here.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
Member of the Public:	Are the presentation slides available?	**General**
Member of the Public:	It's entirely possible that you could add up the best practices and they would not meet the adequacy that we might see as we try to electrify so many things. How did the study deal with that?	**IRP Report**
Member of the Public:	Is demand response, for lack of better words, curtailment of the load on the demand level?	**Load & Energy Efficiency Forecasting**
Pine Gate Renewables:	How are you thinking about the participation of storage in the market, given it might not be a wholesale electricity market by then? And what are all the different services that the storage is providing? And does that change with the type of market structures?	**Reliability, Resilience & Resource Adequacy**

Pine Gate Renewables:	You talk about LOLP (Loss of Load Probability) being the gold standard, like moving to ELCC (Expected Load Carrying Capability) and different types of ELCC methodology. How are you looking at the net energy peak for this scenario? Or are you just looking at one hour in the peak summer evening after solar has ramped down?	**Reliability, Resilience & Resource Adequacy**
CSolPower:	Looking at the different utilities' [plans] for what is coming on online, there is still way too much natural gas, and not enough wind. So, [is this study] based on what has been in previous plans, and not the reality of addressing climate change?	**General**
Member of the Public:	[Is there any excess generation available for use, like that sold in the market, for example?] (Slide 31)	**General**
Member of the Public:	We're a water shortage region. How has that come into the planning?	General
Office of New Mexico Attorney General:	The study took the load forecasts at face value rather than evaluating them. Then you mentioned 2% load growth, I believe. How much of the future need is driven by this expectation around high load growth? I certainly understand electrification and EV load. But some of the load growth, generally, was for population growth and industrial load. And there have been patterns of historically over-projecting load growth that doesn't materialize.	**Load & Energy Efficiency Forecasting**

Office of the New Mexico Attorney General:	[Regarding] the expected availability of existing legacy resources--the existing coal and gas plants--there's a lot of attention around the declining ELCC's for renewables and how they fall off as penetration increases. Was there consideration about how the availability of existing resources decreases as they	**IRP Report**
	age or was that outside the scope [of the study]?	
Member of the Public:	What kind of changes could be made in the storage of water? There are many cultures that store water underground, pipe water underground, or have open systems where evaporation is a major issue. Is that something that tangentially we need to address or get put into the conversation?	**IRP Report**
Member of the Public:	How do we anticipate moving to off grid? Are people putting their own batteries onto their own solar systems, and how will they interact with the grid? How does that in the long term, or even the near term, impact what we're doing here?	**Grid Mod**
CSolPower:	[The IRP process should discuss the electrification of vehicles and how residential battery storage might work beyond individual household use.]	**Load & Energy Efficiency Forecasting** **Grid Mod**

RETA:	In the last few PNM IRPs there have been a number of energy storage projects that have been projected to happen-- some estimated to be completed by this time. How many of those are hung up by supply chain problems that have been getting in the way of solar [projects]? Do you know about the progress of those various solar storage projects?	**Modeling**
InterWest Energy Alliance:	Your regional scope includes New Mexico and Arizona, but it does not include California or any other part of the Southwest. How do you think your conclusions would change if you add in California?	**Reliability, Resilience & Resource Adequacy**
InterWest Energy Alliance:	[How do you think] joining an RTO (Regional Transmission Organization), or forming an RTO, [would affect] some of the conclusions that you've made?	**Reliability, Resilience & Resource Adequacy**
InterWest Energy Alliance:	I know an RTO is not a short-term fix, but shouldn't your longer-term look include looking at RTO development and doing the transmission upgrades and new builds needed, first identifying those, and then including them in your planning? Doesn't this all support that direction for your IRP?	**Reliability, Resilience & Resource Adequacy**

CSolPower:	Hydrogen gas turbines are not the solution for electricity generation, which needs to be done only by wind, water, sun, and some geothermal. We've waited so long for climate action, that we now need to actually move into World War II style deployment of wind and solar. And yet, we are not utilizing the wind that we have in eastern New Mexico. We need to make sure we're looking in the right direction and going as fast as we need to go because [the generations after us] deserve a sustainable planet.	**General**
Member of the Public:	When you say scenarios or extreme weather scenarios, are you talking about a specific duration?	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	Did you assume [in the scenarios] any changes to the hardening of any of the facilities for either extreme heat or extreme cold?	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	Have you thought about what kind of market structure would make the conservative use of the battery versus the sort of straightforward arbitrage use more likely or profitable?	**Reliability, Resilience & Resource Adequacy**
InterWest Energy Alliance:	Was your assumption in this study of a 4-hour battery? And if not, why? And if it was lower than that, why?	**Reliability, Resilience & Resource Adequacy**
InterWest Energy Alliance:	What are you seeing on the horizon in terms of the likelihood of reasonable technology for a longer-term battery in the future?	**Reliability, Resilience & Resource Adequacy**

Member of the Public:	It seems to me that [your resource planning] approach could also be for, say, planning on the contingency reserve requirement, or instead of maybe a severe event, it could be a severe curtailment of some generation resource or market resource. Could something like this be applied to [your modelling], assuming that the current standard doesn't change?	**Reliability, Resilience & Resource Adequacy**
CSolPower:	Is the availability for 2033 64,000 megawatts? (Slide 18)	**General**

June 8, 2022: Technical Session #1

On June 8, 2022, PNM held the first of a planned series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the 2023 Integrated Resource Plan (IRP). Director of Integrated Resource Planning Nick Phillips acknowledged the desire of stakeholders to be more involved in the early stages of the IRP's development and to maintain a role throughout the process as PNM develops inputs to the modeling framework.

Mr. Phillips encouraged participants to offer their ideas about new or different ways of modeling, both qualitative and quantitative. He stressed that the focus of the technical sessions is to reach the best possible development process for PNM customers through the examination of different perspectives and pathways—all with the goal of being 100% carbon free by 2040.

After a review of the key findings of the studies presented at the May 25, 2022, meeting, Mr. Phillips presented the modeling framework and opened the floor for questions, which covered, inter alia, loss of load probability modeling, LOLE versus EUE metrics, and system resiliency in the face of extreme weather.

A full list of questions follows below.

Meeting Attendees

A total of 27 stakeholders, not including PNM staff, attended the meeting, including members of the public and representatives from the following organizations: Brubaker & Associates, CSolPower, InterWest Energy Alliance, and Sandia National Laboratories.

Meeting slides can be found here.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
Brubaker & Associates:	The last time around you did some limited work when doing resource selection, allowing certain transmission upgrades or projects to be selectable in the optimization. Obviously, there are limitations on computing capability. Do you envision doing some of that this time around as well, [to the extent] it's workable and practical within current computing limitations?	**Transmission**

Brubaker & Associates:	How is transmission going to be worked into the IRP? What assumptions are going to be made about market support? What are the plans to tackle ELCC (Expected Load Carrying Capability)?	**Transmission** **Reliability, Resilience & Resource Adequacy**
CSolPower:	Have other systems reached 100% decarbonization? There should be others like Hawaii and Vermont and a couple of other states that maybe are planning on it. What are they doing?	**Reliability, Resilience & Resource Adequacy**
Sandia National Laboratories:	While doing the planning, have you taken into consideration the inertial requirements of the system to maintain frequency security as we replace more conventional generation with renewable resources?	**Reliability, Resilience & Resource Adequacy**
Sandia National Laboratories:	How do we establish a baseline for portfolio metrics such as the EUE (Expected Unserved Energy), which has been around for a long time now? If you look at literature that goes back to 1970s, you can see the matrix calculated there. So, there's a lot of literature out there which have used IEEE test systems to calculate the EUE for a lot of systems and a lot of scenarios. Maybe that is something you would want to look at as a starting point for establishing a baseline. And I can help you with that if you want.	**Reliability, Resilience & Resource Adequacy**
Sandia National Laboratories:	Is storage duration critical? Or is storage volume more important? And what is the cost tradeoff? I would say it depends a little bit on what the application is. Are we trying to farm up wind and solar or are we trying to use it as backup? That's something I would be willing to help with as well.	**Reliability, Resilience & Resource Adequacy**

Member of the Public:	If we are looking at establishing a baseline level of service or capacity for summer or winter resilience, are there any contractual requirements if greater demand is placed on the West as a whole, such as if Hoover or Glen Canyon Dam are no longer able to supply power? This may, if there are contractual agreements, affect the sizing of systems.	**Reliability, Resilience & Resource Adequacy**
CSolPower:	[In response to the question about tradeoffs, I would definitely go for carbon-free over .1 LOLE (Loss of Load Expectation). That's just my statement: I would choose that we go carbon-free first. I would rather have one less day of no power, considering all the extreme weather events that are going to result from carbon emissions.]	**Reliability, Resilience & Resource Adequacy**
Sandia National Laboratories:	Are you using Monte Carlo simulations with forced outage rates of the resources to run the LOLE models?	**Reliability, Resilience & Resource Adequacy**
Sandia National Laboratories:	Regarding the distribution of uncertainties, you mentioned that you had book-ended the window of your uncertainties. Are there any? Have you investigated looking outside that window at extreme cases that might not have happened over the past 40 years? That might be an interesting exercise.	**Reliability, Resilience & Resource Adequacy**
CSolPower:	Have you considered accounting for predicted extreme weather? We know the climate is changing and these extreme events are becoming more common. The weather is definitely getting hotter. Looking backward may not be sufficient to give us a realistic view of what's going to be happening in the next 40 years. Is there any effort to work with NOAA? I'm sure that they have done some modeling as to predicted weather.	**Reliability, Resilience & Resource Adequacy**
Member of the Public:	Does the [electrification of the larger economy] impact the loss of load probability or the loss of load expectations in any way?	**Reliability, Resilience & Resource Adequacy**

InterWest Energy Alliance:	Your [example in the presentation] used a 2-hour battery. That doesn't seem to be a good assumption. Why not use a 4- hour battery since those are available now?	**Reliability, Resilience & Resource Adequacy**
Brubaker & Associates:	This goes back to the concerns in response to the 2020 IRP. I think the thing to think about is that you are making assumptions about where you're going to be in different timeframes so that you can divide up the synergistic benefits across the different resource types. Is this in any way directing an outcome and the economic optimization that will take place later? And what might be revealed is if you start going a different direction in the optimization, then you are assuming where to balance and what the resources are going to be.	**Reliability, Resilience & Resource Adequacy**
Brubaker & Associates:	You might have to potentially look at both LOLE and EUE. This raises a question: Which is more constraining? The other thing that comes to mind is that it may be that EUE is a better metric than LOLE when it's looked at more carefully; It more optimally identifies how much capacity you need to get a certain level of reliability or for more broadly, resilience.	**Reliability, Resilience & Resource Adequacy**
CSolPower:	Does this particular graph (Slide #18) relate to battery penetration in megawatts? How does that relate to the percentage of the capacity of the system? Or it's related to solar and wind?	**Reliability, Resilience & Resource Adequacy**
CSolPower:	This battery penetration is assuming it's all lithium-ion batteries, and you're stating that it's 4-hour capacity. Are you going to include other studies on other energy storage methodologies or technologies?	**Reliability, Resilience & Resource Adequacy**
CSolPower:	Does FERC have any standards for utility?	**Reliability, Resilience & Resource Adequacy**

Member of the Public:	Will PNM consider scenarios for electrification of the economy beyond cars by 2040?	**Grid Mod**
Member of the Public:	As we get distributed generation coming on in small pocket areas or micro grids, what happens when you have little pockets spread throughout the system? How do we get that to feed back into the system? How do we begin to understand that? What are some of the factors we should be looking for or where we should be looking for data when we may not have much of it in the PNM service area?	**Grid Mod**
CSolPower:	I just wanted to make sure that you're going to go over the storage requirements that you were looking for. [I'm seeing] 5-hour with 500 megawatts, and I would like to know how often that's expected. [Perhaps it was related to an RFI.]	**IRP Report**
CSolPower:	Can PNM consider if we are asked to go carbon free before 2040, or 2033 or 2030?	**Modeling**
Sandia National Laboratories:	How are you modeling the solar modeling and wind profiles for all the scenarios?	**Modeling**
Sandia National Laboratories:	Let's say you're using 100 samples for your simulation. So, for each sample, how are you varying the uncertainty? Are you varying the profiles? Are you considering the extreme scenarios for renewables?	**Modeling**
CSolPower:	Will the [scenario] form include different scenarios? And what kind of variables can we throw in there?	**Modeling**

June 22, 2022, Technical Session #2

On June 22, 2022, PNM held the second in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the 2023 Integrated Resource Plan (IRP). The meeting was devoted to a presentation of the scope of work for the energy efficiency (EE) study AEG is conducting for PNM.

The objectives of the study include incorporating key updates from the 2019 study; developing new projections of EE potential; and developing IRP bundles. AEG's overview generated questions covering, inter alia, the conversion of evaporative cooling and energy savings (in the IRP bundles) from demand response programs such as smart thermostats. In addition, Astrapé Consulting also informed participants regarding Strategic Energy & Risk Valuation Model (SERVM) changes for the 2023 IRP regarding modeling market assistance in the context of determining the reliability metrics for portfolios.

A full list of questions follows below.

Meeting Attendees

A total of 34 stakeholders, not including PNM staff, attended the virtual meeting, including members of the public and representatives from the following organizations: Brubaker & Associates, CSolPower, NV5, New Mexico State University, and Sandia National Laboratories.

Meeting slides can be found here.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
Brubaker & Associates:	Is the Miscellaneous category just everything that doesn't fit into the other categories?	**Load & Energy Efficiency Forecasting**
Sandia National Laboratories:	Do you assume in your baseline load forecast this conversion rate? Over time, is what actually happens that difference could be due to energy efficiency incentives or incentives to not convert to AAC? Can part of it be forecast error? Does all of that get counted as energy efficiency?	**Load & Energy Efficiency Forecasting**
Sandia National Laboratories:	Is there a trend happening around the conversion of evaporative cooling to air conditioning? Do you assume in your	**Load & Energy Efficiency Forecasting**

	baseline load projections about what that conversion rate might be?	
Sandia National Laboratories:	Demand side management is not being considered as part of energy efficiency, correct? Are you asking about demand response—that is some sort of customer response based on some sort of price signal or program?	**Load & Energy Efficiency Forecasting**
Sandia National Laboratories:	Will the hourly estimates of how much energy savings is going to happen based on each of the bundles include, for example, smart thermostats and other demand response programs?	**Load & Energy Efficiency Forecasting**
NV5:	How do electric vehicles fit into the modeling?	**Load & Energy Efficiency Forecasting**
Member of the Public:	Is there any potential for geothermal or some kind of heat from the ground coming into this mix? Are we looking up to 20 years out?	**Modeling**
Member of the Public:	Can you apply the service stress test to the significant low carbon portfolios you produced in your IRP capacity expansion model?	**Reliability, Resilience & Resource Adequacy**
CSolPower	Does rooftop solar count toward energy efficiency?	**Load & Energy Efficiency Forecasting**
Member of the Public:	Can you provide the results of the one-week analysis? Would they be pretty quick to perform on the portfolios that come out of capacity expansion?	**Modeling**
Member of the Public:	We need to keep talking about fossil fuels: how they are being phased out and where those options are. Sometimes additional, more attractive fossil fuels, like gas versus	**Reliability, Resilience & Resource Adequacy**

	coal, need to stay in the conversation in this transition period because the public doesn't really understand this issue very well.	

July 6, 2022, Technical Session #3

On July 6, 2022, PNM held the third in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the 2023 Integrated Resource Plan (IRP). The meeting was devoted to a presentation by Itron on the scope of work concerning the fundamentals associated with developing PNM's 2023 long range load forecast for the IRP. Additionally, PNM presented its approach regarding the candidate resource pricing methodology for the 2023 IRP.

Director of Integrated Resource Planning Nick Phillips explained that the session was a preliminary look and that the forecasts would be finalized in coming months. He added that PNM had taken into consideration comments concerning the 2020 IRP's long-term load forecasts and stressed that the session gives stakeholders the opportunity to discuss the various components going into the 2023 forecasts as well as the draft scenarios under development.

Meeting Attendees

A total of 32 stakeholders, not including PNM staff, attended the virtual meeting, including members of the public and representatives of the following organizations: Brubaker & Associates, InterWest Energy Alliance, New Mexico State University, the New Mexico Public Regulation Commission (NMPRC), the New Mexico Renewable Energy Transmission Authority (NM RETA), Sandia National Laboratories, and Western Resource Advocates (WRA).

Meeting slides can be found here.

Attendees raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NMPRC:	Does the solar implementation assume that there is adequate feeder capacity, smart meters, etc. to allow the proposed residential solar projects to be built?	**Grid Mod**
WRA:	Please say a little bit more about distributed storage. Did you mean on the utility side of the meter? Or did you mean customer owned and controlled storage?	**Grid Mod**

InterWest Energy Alliance:	Do you plan to do a comparison of the impact on the night and early morning hours? I would assume that demands at that time are much lower.	**Load & Energy Efficiency Forecasting**
InterWest Energy Alliance:	Is your key need, especially during summer peak, going to be capacity or energy in the 6-9pm window, so what happens when you thicken that self-generation slice at the top (Slide: "Hourly Load on Peak Day") that just pushes your peak into the evening hours when the sun is going down or down? Is that right—partially—so that this is just a snapshot and doesn't represent the full system dynamic?	**Load & Energy Efficiency Forecasting**
New Mexico State University:	We've heard that the average temperature in New York (or for PJM) was going up .7, and we don't really know what the trend is for New Mexico. I'd like to see a scenario that does take into account increased heat waves, the increased occurrence of heat waves in the summer, because that's what's going to stress your system. So, can we look at the trends we know about in New Mexico, project out increases in heat waves, and make a scenario for that?	**Load & Energy Efficiency Forecasting**
Member of the Public:	Is there any elasticity between behind the meter solar and community solar and electricity rates? If so, is that a signal friction factor?	**Load & Energy Efficiency Forecasting**
InterWest Energy Alliance:	Is there much or any behind the meter by commercial industrial customers? And how does that affect your analysis?	**Load & Energy Efficiency Forecasting**
NM RETA:	What factors contributed to the forecast and increased residential behind the meter capacity?	**Load & Energy Efficiency Forecasting**

New Mexico State University:	The question here is climate change impacts the U.S. at different rates, depending upon the region. What is the trend? What is the trend in the Southwest versus New York, PJM?	**Load & Energy Efficiency Forecasting**
InterWest Energy Alliance:	It would be helpful to repeat this discussion in writing somewhere—the amount of increase per decade and the fact there are fewer cold days, more than hot days. Will there be a detailed report written?	**IRP Report** **Load & Energy Efficiency Forecasting**
InterWest Energy Alliance:	Why use 2015 to 2018? Why not use more recent billed sales data (Slide 15)?	**Load & Energy Efficiency Forecasting**
Brubaker & Associates:	What are the components? Are you using government forecasts?	**Load & Energy Efficiency Forecasting**
Brubaker & Associates:	I know this is preliminary. This is obviously a very big change, particularly on the residential. What are the big drivers of this change?	**Load & Energy Efficiency Forecasting**
Brubaker & Associates:	Is the hourly weather data, both the temperature data and the global horizontal irradiation, assuming that's all in sync on an hourly basis?	**Load & Energy Efficiency Forecasting**
NMPRC:	Will there be a way for developers to know which locations will be the highest adjustments? This seems to indicate transmitted adjustments were made after bids are submitted to PNM. Will developers have access to the information later, that is to say their final project cost as calculated and adjusted by PNM?	**Modeling**
InterWest Energy Alliance:	I understand that the answer to this question may be different in the near term versus the long term because I've heard	**Modeling**

	PNM say many times now that we know where we're going—to a zero-carbon system. How to get there between now and then? Can you address when the need pushes into the late evening, early morning hours? What do you see as the options, resource wise, to fill that gap?	
Member of the Public:	How do you factor recharging batteries into this model?	**Modeling**
Member of the Public:	With the sales drop off, how does that impact on PNM for generation? And what is the impact on PNM's business model?	**Modeling**
Member of the Public:	What kind of fossil resources are needed for the transition to a non-carbon state of affairs?	**Modeling**
Member of the Public:	We can concede a lot about solar. But does wind generation also factor in here? Specifically, how much does weather impact the wind generation capacity for us and where does that come in?	**Modeling**
Brubaker & Associates:	Are you are still planning a technical session for stakeholders in the fall to discuss the import limit?	**Modeling**
InterWest Energy Alliance:	Shouldn't your heat wave analysis also include a length in time, depth in temperature, and demand and geographic breadth since these are assumptions that affect your assumptions regarding market availability?	**Load & Energy Efficiency Forecasting** **Reliability, Resilience & Resource Adequacy**
New Mexico State University:	We're mostly learning about how the baseline was developed for load. and how the stochastic scenarios affect production on the reliability side, but does the reliability model also apply stochastic	**Reliability, Resilience & Resource Adequacy**

	variation to this baseline load forecast? Where would different load scenarios go?	
NMPRC:	Is a decent summary that you are largely approaching these transmission constraints in the IRP by planning for large projects, a couple of 100 megawatts where one or two developers will serve as a kind of anchor customer that will take responsibility for the transmission upgrades needed for their projects?	**Transmission**
InterWest Energy Alliance:	PNM, having acknowledged transmission constraints in the east, why not look at those as individual pieces of the IRP as well, instead of just linking it to particular resources?	**Transmission**
InterWest Energy Alliance:	My understanding is that PNM is looking to link transmission to a particular resource in a particular location, and then ascribe the costs to that resource or development or whatever. Is that right?	**Transmission**
Member of the Public:	Is transmission also an issue with wind that may be less of a transmission issue as solar?	**Transmission**
NM RETA:	Why does the minimum and maximum difference each year increase significantly (Slide 17)?	**Load & Energy Efficiency Forecasting**
PNM:	Has anybody started using a 50/50 weather forecast for their work? Are they starting to look at 75/25? Or 90/10? Is anybody starting to ask for anything other than a 50/50 weather scenario to look at how should we be planning as we start to recognize more and more what's going on with the changing climate?	**Load & Energy Efficiency Forecasting**
PNM:	If we start to think about climate change, and extreme weather, how might you adapt normal weather looking forward, if you	**Load & Energy Efficiency Forecasting**

	want to consider that maybe there's going to be more extreme weather, more significant increases, as opposed to what's happened over the last 20 years?	

July 27, 2022, Technical Session #4

On July 27, 2022, PNM held the fourth in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the 2023 Integrated Resource Plan (IRP). PNM staff and a representative of the firm CDG Engineers, Inc. (CDG) presented a host of modeling updates using the EnCompass software that will be incorporated into the upcoming results.

This presentation on modeling focused on PNM's continuing improvements and performance testing as well as updating the modeling of energy efficiency bundles. CDG presented an overview of long duration storage featuring technologies that would move beyond the lithium-ion battery storage featured in the 2020 IRP to include pumped storage and hydrogen storage.

Meeting Attendees

Director of Integrated Resource Planning Nick Phillips and the presenters welcomed questions and feedback on the framework and storage options from the 40 stakeholders attending the virtual session. Participants, not including PNM staff, included members of the public and representatives from the following organizations: Brubaker & Associates, CSolPower, Form Energy, Grid Strategies, InterWest Energy Alliance, New Mexico State University, New Mexico Public Regulation Commission (NMPRC), New Mexico Renewable Energy Transmission Authority (NM RETA), and Sandia National Laboratories.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NM RETA:	Once the record peak is final, will PNM be breaking down the generation source contributions that were used to meet the peak: For example, what came from San Juan? What came from natural gas generation? What came from solar? What came from wind?	**General**
Member of the Public:	How would increased distributed generation, especially if it has some backup storage of its own, be factored into the modeling?	**Load & Energy Efficiency Forecasting**

NMPRC:	Slide 31 shows that if you had, say, a 100 megawatt 4-hour battery storage system, you could dispatch it for 50 megawatts for 8 hours. Would that have any effect on the life of the batteries themselves, or are there any concerns along those lines?	**Modeling**
Sandia National Laboratories:	Is anyone recovering the H2O after hydrogen compulsion at utility scales?	**Modeling**
NMPRC:	Would anyone from PNM like to comment on whether the source of hydrogen matters for meeting RPS requirements—whether the current RPS requirements or lifecycle are purely at the point of degeneration, or how and if that is a part of the overall IRP analysis, especially in the longer timeframe?	**Modeling**
NMPRC:	Can PNM comment on whether the source of hydrogen matters for meeting RPS requirements—whether the current RPS requirements or lifecycle are purely at the point of degeneration, or how and if that is a part of the overall IRP analysis, especially in the longer timeframe?	**Modeling**
Brubaker & Associates/NM RETA:	For the most expensive energy efficiency bundle, maybe it would make sense to model that and multiple bundles if the EE (energy efficiency) products are different.	**Modeling**
CSolPower:	What's the readiness technology level for burning hydrogen?	**Modeling**
CSolPower:	What is the proposed percentage of hydrogen to natural gas for the combustion turbines?	**Modeling**
InterWest Energy Alliance:	What did the results look like with higher medium import assumptions rather than low import assumptions (Slide 30)?	**Modeling**
Sandia National Laboratories:	[Looking at] the payback and generation plots (Slide 28), I was just curious about the	**Modeling**

	terminology payback first generation. It sounds like difficult math: if you're getting more than you're putting in.	
CSolPower:	Considering that to even consider hydrogen—the power generation industry is energy intensive—is dangerous and takes away from an easily decarbonized electric grid. How do you justify this analysis?	**Modeling**
Member of the Public:	Following up on the question about water availability, broadly, how much activity is being seen on promoting evaporation reductions of systems that have been used in other parts of the world, such as the ancient canal system from the Middle East, and also in Peru, where aqua like structures run underground? This is just clearly an issue beyond the IRP, but I'm putting it on the record here.	**Modeling**
Sandia National Laboratories:	What is the minimum duration requirement that was built into the assumptions for LDES [Long Duration Energy Storage] technologies?	**Modeling**
NM RETA:	Are the capital costs of the specific storage technologies a viable parameter in the modeling? Or is the storage cost model a generic unit cost?	**Modeling**
New Mexico State University:	Could you be specific about what parameters from this PHS (Pumped Hydro Storage) analysis would feed back into EnCompass capacity expansion models?	**Modeling**
NM RETA:	What is the renewable contribution to total generation assumed in 2035? When this scenario is run, where are you at in your ETA ramp?	**Modeling**
InterWest Energy Alliance:	How feasible is pumped storage in the desert Southwest and New Mexico? How much water is consumed through evaporation? What are the assumptions	**Modeling**

	about water availability during summer peak? What about monsoon failure?	
CSolPower:	When you assume the renewable energy drought, did you assume less need?	**Modeling**
CSolPower:	What is it going to take for PNM to include thermal storage?	**Modeling**
Sandia National Laboratories:	[Based on Slide 15], it seems pretty safe to assume that those lower cost energy efficiency bundles are going to be selected by the capacity expansion plan. So, I don't see the harm in free solving the model and saying, if the energy efficiency bundle costs less than $35, less than $25 a megawatt hour, just force it in and don't spend the computational power to figure out what should be obvious.	**Modeling**
Sandia National Laboratories:	Are these results using the zonal model, or are you assuming a copper sheet model? Adding the nodal model and assessing/comparing computational tradeoffs with commitment constraints may be interesting to evaluate.	**Modeling**
InterWest Energy Alliance:	Some consumer advocates acknowledge that this is a heavy lift for software programs. And yet, we know that huge computers exist in the world. Could you simply resolve that and do this really complicated multivariable modeling by investing a lot more money in your software? I realize that there are real constraints to the money you want to spend but if you spent more, what could you do? What's really possible out there?	**Modeling**
Form Energy:	Can you talk a little bit about the temporal granularity using the capacity expansion component of the modeling**?**	**Modeling**
NM RETA:	Has the recent decision in the Supreme Court of the United States regarding EPA air	**Modeling**

	quality program and implementation affected requirements for PNM CO2, as used for IRP purposes?	
Sandia National Laboratories:	Please give an example of what might be considered generic resource options.	**Modeling**
NM RETA:	Does the energy market input include future PNM membership in an RTO (Regional Transmission Organization) in the later years of the 2023 IRP?	**Reliability, Resilience & Resource Adequacy**
Form Energy:	Will there be a more in-depth discussion of the first step discussed in this process? That is, the ELCC (Expected Load Carrying Capability) and PRM calculation methodology and SERVM (Strategic Energy & Risk Valuation Model)?	**Reliability, Resilience & Resource Adequacy**
InterWest Energy Alliance/Grid Strategies:	Does ignoring generator minimums by using partial instead of full commitment for the capacity expansion miss some of the value storage provided by charging during periods when generators are at a minimum?	**Modeling**

August 17, 2022, Public Advisory Group Day "Methods For Accounting For Correlated Outages And Derates Of Conventional Generators"

PNM hosted the first Public Advisory Group Day of the 2023 IRP planning cycle on August 17, 2022. Michael Goggin of Grid Strategies LLC gave a presentation on methods for accounting for correlated outages of conventional generators.

Key points included:

- Correlated conventional generator outages due to equipment failures and fuel supply interruptions have played a major role in recent reliability events.
- Effective Load Carrying Capability (ELCC) methods capture correlations in output patterns for renewable and storage resources. Conventional generators also exhibit correlated outages and derates, but those are not typically accounted for.
- Ignoring conventional generator correlated outages can bias resource selection, and mask reliability risk.
- Several grid operators and others have developed methods for evaluating risks to resource adequacy and resilience from correlated conventional generator outages and derates. Some of these methods apply ELCC to conventional generators using historical patterns for generator outages, while other methods focus more on testing a large number of potential generation mixes under a range of plausible conditions.

Meeting slides can be found here.

September 13, 2022, Technical Session #5

On September 13, 2022, PNM held the first of two technical sessions covering issues related to transmission and the 2023 IRP (Integrated Resource Planning) process. This was the fifth in the series of technical sessions for stakeholders devoted to providing a transmission framework and discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP.

PNM representatives Laurie Williams, Director, Transmission and Substation Engineering, and Tom Duane, Manager, Transmission Planning, gave an overview of the role of transmission in utilities' plans for energy transition, PNM's current transmission system, and the regulatory environment for transmission that governs PNM and other utilities. They fielded questions and entertained comments from participants and PNM staff concerning the FERC (Federal Energy Regulatory Commission) process, proactive transmission planning, and various interconnection options, among other issues.

Meeting Attendees

Twenty-two stakeholders attended the virtual session. Participants, not including PNM staff, included members of the public and representatives from the following organizations: NM AREA, InterWest Energy Alliance, and Sandia National Laboratories, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NM AREA:	NM AREA will be most interested in PNM's specific plans for its 2023 IRP to meet Ordering Paragraph B of the Commission's July 25 Order.	**Transmission**
Member of the Public:	Are there FERC withdrawal penalties for applicants?	**Transmission**
Member of the Public:	To whom are you targeting this information? Is this to the general public or just specific financial interests? It seems that the general public is not very well informed about much of what was covered today.	**Transmission**

InterWest Energy Alliance:	[Concerning] the chicken and egg problem. I want to put in a plug for proactive transmission planning. We've encountered this problem for a long time, and we found that the only thing that works is proactive transmission development. You know the CREZ (Competitive Renewable Energy Zone) example was kind of the first one that did this. At that point, it was kind of a risky and novel idea that we are going to designate these zones, we know where renewables are, and we think they'll develop. And they did. We built it and they came. We've seen it replicated in SPP and MISO, with the MVPs (Multi Value Projects) and [in California]. All these examples we've seen have been very successful. And given where the renewable cost trends are with the IRA tax credits, and most importantly with New Mexico state law basically specifying where your generation mix is, it seems to me there's extremely low risk that you would build transmission to these high real resource areas. And we know where these are, and the renewable resources are not going to change. We know where the wind is and where the sun is. It seems almost no brainer if you were to build transmission, proactively plan transmission to those resource areas, maybe informed by projects in the queue, and even do some type of public season process where there are some deposits, some skin in the game from developers to ensure they are real. That's been used in other regions as well.	**Transmission**

	I'm very confident this would work and get you much more cost energy at a lower cost of transmission because you could right size it to accommodate the scale of the project for one interconnect that you need to meet your load. Basically, you can do proactive transmission planning and incorporate this into your process. I think that is essential for doing this cost-effectively.	
Sandia National Laboratories:	When an interconnection is made for a specific generator, how much of that cost eventually goes into the transmission rate base? It seems like some facilities could be useful for interconnecting more resources and others might be only used for that one generator.	**Transmission**
InterWest Energy Alliance:	Are you thinking in terms of incentivizing developers to focus on particular areas just to be more efficient with your dollars? Are you thinking that you will be focusing some investments yourselves to enhance the interconnection opportunities in particular areas, to kind of create the hot highway and they will come and focus on those particular areas?	**Transmission**
InterWest Energy Alliance:	Am I to understand from the previous few slides (Slides 30-35) that these transmission options are all selectable in the IRP model? Can you describe what is selectable in the IRP model?	**Transmission**
PNM:	Can you provide any color around the cost of the permitting/CCN labels (Slide 30)? The cost last time was obviously lower than this when we looked at it, a couple years ago in that IRP cycle. Is the permitting and CCN timeframe there five years, is that the entirety of the	**Transmission**

	process, or is there additional time on top of that for construction and other things that need to be done?	
InterWest Energy Alliance:	[Concerning AC DC projects], is it in our interest, is PNM having discussions, particularly with Sun Zia, about essentially integrating the eastern end of that into the New Mexico system so that you take advantage of load diversity with other parts of the West, particularly, areas to the West--most notably California--that have built a lot more solar? There's a lot of cheap generation available during most of the afternoon in New Mexico that could flow west to east along those lines that maybe wasn't envisioned 10 years ago when those lines were initially sketched out. Is that something that would be of interest, is PNM exploring, potentially making some of those lines network elements?	**Transmission**
PNM:	You've given some of the significant cost increases related to the repair of the AC/DC converters. It may have doubled from the last time those were estimated, or something to that effect. Do you have an idea of what the cost of doing these lines today would be as opposed to when they were done just a few years ago?	**Transmission**
PNM:	Are there interconnection costs that are network upgrades as well?	**Transmission**
PNM:	For resources that come online that do not have a defined customer yet--they're building and they're assuming that they will find a customer once it's built--how are we studying the network upgrades that may be required?	**Transmission**

Member of the Public:	Do developers have any responsibility for what they do to the system? They put their generation unit out there somewhere with a big wind farm. They put in the generator tie, and then they don't care what happens? Are there no controls?	**Transmission**
PNM:	Do you have a thought why most of these interconnection points (Slide 26) are situated along the major transmission corridors?	**Transmission**
InterWest Energy Alliance:	In your off-peak period, where you've got high winds, high solar, you've got substantial flows to the northwest. Are those off-peak periods times at which some of our neighbors to the west, and I'm thinking in particular California, they might still be on peak, or that they have higher needs that we can fill? I'm wondering if that occurrence can help us with some geographic diversity enhancements and filling neighbor's needs, when perhaps we have excess during these off-peak periods.	**Transmission**
Member of the Public:	How much do you anticipate that some users, perhaps even the non-retail users, which are perhaps [a] larger [segment], would peel off and become kind of separate independent nodes of their own to do their own power generation, solar with battery backup, things like that, and how would that impact the need for transmission?	**Transmission**
Member of the Public:	I just continue to be concerned [about] the changes in the industry overall. The grid is 115 years old, or something like that. Really not very old, in the grand scheme of things. We're trying to look	**Transmission**

	into a crystal ball that's pretty cloudy, looks like to me.	
InterWest Energy Alliance:	What about the thorny issue raised of cost allocation? Do you plan to provide input to FERC on that? What's your view on that issue?	**Transmission**
InterWest Energy Alliance:	What kind of input have you as PNM had into the FERC process? I know it's early days, but what do you anticipate contributing to that, the FERC consideration of its rules?	**Transmission**
PNM:	In terms of all these other customers accessing PNM's transmission system, whether to try to incorporate resources for PNM's use, or to ship out of state, any of those that are not dedicated to PNM retail still affect the way the transmission system is operated. All the interconnection requests that PNM Transmission does from the federal OATT (Open Access Transmission Tariff) standpoint really is the primary driver in the manifestation of changes, investments in the transmission system. Is that fair?	**Transmission**
PNM:	Today, given the resources, the loads and the rights that we have, is there much of any more resources that can deliver into southern New Mexico to then be transmitted up to the northern load centers?	**Transmission**
PNM:	The existing resources in the eastern part of state, the 2,457 megawatts--it's probably about 500 megawatts that's actually contracted or delivered for PNM retail and the rest of it is wholesale being shipped out of state, or something to that effect?	**Transmission**

NM AREA:	Are the 2023 additions for 840 megawatts (Slide 22) additions that are based on the latest updates from PNM to the Commission, that is, the resources that are actually expected to be in service in 2023? Has that been updated to match this number, in line with that, or is it a different number?	**Transmission**
InterWest Energy Alliance:	I just wanted to chime in that the Manchin Bill is currently still being drafted but drafts that are circulating include a cost allocation measure that would allow FERC to determine cost allocation for transmission. And so, I think that is improving some obstacles, certainly for DC lines. But I think cost allocation is one of the biggest obstacles for significantly sized transmissions because it benefits large regions. It's certainly a national network like this, which allows FERC to do that. There's also a parallel FERC effort looking at transition planning and cost allocation. So, there is federal action that is going to help on some of these issues.	**Transmission**
InterWest Energy Alliance:	I have a question about your opinion about [Slide 15]. I see a 35-year study window here, and IRPs generally look at a 20-year study window. [Do] you believe, like I do, that since transmission is such a long-term investment, IRPs don't really fully capture the benefits of investment, similar to the way that this study does?	**Transmission**
InterWest Energy Alliance:	I'm glad to hear you're looking at what it would take to replace or upgrade the converters. Are you looking at just replacing the same capacity? Or are you looking at increasing the capacity so you could transfer more across the ties?	**Transmission**

October 6, 2022, Technical Session #6

On October 6, 2022, PNM held the second of two sessions covering issues related to transmission in the IRP (Integrated Resource Planning) process. This was the sixth in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP for transmission.

PNM consultant E3 gave a presentation comparing transmission analysis in IRPs with transmission planning studies, highlighting the benefits and drawbacks of three approaches utilities are using for incorporating transmission in resource selection and portfolio development in their IRPS. The three approaches are "CREZ" (Competitive Renewable Energy Zones)-style cost adders for resources or locations; scenario analysis of transmission projects; and co-optimization of generation and transmission expansion under the zonal system representation.

Also, PNM staff gave an overview of transmission modeling in PNM's four previous IRPs (2011, 2014, 2017 and 2020) as well as a discussion of zonal and nodal transmission modeling.

Meeting Attendees

Twenty-nine stakeholders, not including PNM staff, attended the virtual meeting, including members of the public and representatives from the following organizations: Hecate Energy, InterWest Energy Alliance, NM AREA, and Sandia National Laboratories, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NM AREA:	One of the things E3 talked about was the scenario analysis, sort of the middle course method. PNM has done some co-optimizations. Very slow. Very limited. And you've done the approach of adding, also on the cost for the transmission as an adder.	**Transmission**

	Could there be some potential, and maybe [this will] depend on [your] RFP results, for [something like] PacifiCorp did - they had a large collection of RFP results, so they had resource options. But they did some scenario analysis, basically comparing one portfolio--if you built a certain transmission project that had been identified in the past as potentially being beneficial--and then take another scenario with an alternative portfolio that's optimized, assuming you don't have that, and then compared [them]. Do you see any opportunity for potentially doing that? Though it might depend on what you're seeing in your results, when you actually get in, to start doing the IRP.	
NM AREA:	Do you see this as really a tool for better understanding congestion going forward because, again, the zonal models have limitations and it's an art to putting those together, right? So, there's some art to this but this would give you a much more accurate picture of the congestion situation. For example, you could run future portfolios for a sample year in the future, or you could look at [whether] there congestion transmission projects that make sense for the PNM transmission system as a whole. That is, not just PNM retail but PNM retail and the other transmission customers. Is that how you're seeing this?	**Transmission**
Hecate Energy:	Do we model contract path versus do we model just the physical flows relative to the inverse impedance of the system?	**Transmission**

NM AREA:	I'm struggling understanding the difference between these two (Slide 21). I'm assuming the initial modeled topology is essentially related to the slide previous to this.	**Transmission**
InterWest Energy Alliance:	[Regarding Slide 20], I think what I heard you say is that what you did is identify transmission projects from each of these five zones, but only in relation to a known generation resource within each of these five zones that needed transmission in order to get the energy to load. But if you didn't have a known resource in one of those zones, there was no impetus to build any transmission. Is that about right?	**Transmission**
Sandia National Laboratories:	Maybe [this is] related to the third option, the more complex and customized generation and transmission**.** With the zonal model, you get those transmission investments kind of from a zonal basis. So, I was just curious, in your screening of current IRPs, or even what you have (on Slide 15) on integrated system planning, what are some methods utilities are taking to kind of translate those aggregated transmission investments into actual transmission projects?	**Transmission**
Hecate Energy:	When a generator joins a data collection process, there'll be some reliability updates assigned to it, right, based on the interconnection study? So, are we talking about upgrades? Can you explain that?	**Transmission**
InterWest Energy Alliance:	Do any of these methodologies take into account benefits, such as reliability benefits, and assign a value	**Transmission**

	to them that can then be assigned a dollar value instead of just the amorphous 'it increases reliability but we're not assigning any value to it' that I've heard in several IRPs.	
Hecate Energy:	I think you need the cost of generation also, like different generation types will have different costs, right? Are you using any numbers for generation when you look at these scenarios and evaluations? (Slide 14)	**Transmission**
NM AREA:	Would you say it's fair to say that the scenario analysis approach works particularly well when a utility has identified various candidate transmission projects or expansions that have clear strategic benefit? And if scenario analysis kind of works well for identifying when those projects really become either cost effective or have significant benefits to justify moving forward? [Does] it work well, in that respect?	**Transmission**
NM AREA:	This is more of a comment. You've partly acknowledged [that] there are some exceptions, but not just in CAL ISO/MISO: PacifiCorp, for example, [with the] Gateway South project that was fully integrated in their most recent IRP. And the decision was integrated on both the resources and moving forward with that transmission project. And it could be argued, to some extent, some of NV Energy's recent transmission developments are tied together. I mean, not so much in an IRP, but the consideration of resources was a major driver moving forward [with] those transmission projects.	**Transmission**

	So, I agree, it's somewhat in its infancy, but it is happening. And there are examples.	

October 17, 2022, Technical Session #7

On October 17, 2022, PNM held a technical session to provide updates on its grid modernization filing and summaries of responses from two RFIs (Requests for Information) solicitations: one for emerging technologies that meet PNM's decarbonization goal and can be fully implemented after 2030, and one for projects with a longer development lead-time that could bridge the gap between near-term RFP responses and post 2030 emerging technologies. This was the seventh in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP (Integrated Resource Plan).

PNM summarized and discussed the October 3, 2022, filing with the New Mexico Public Regulation Commission, the company's high-level grid modernization plan, and associated upgrades to the distribution system. PNM staff also gave a preliminary overview of the responses to the two RFIs, which covered concentrated solar power; demand response software; parts fabrication and services; pumped hydro storage; solar/battery hybrid; thermal energy storage; and transmission.

Meeting Attendees

Nine stakeholders, not including PNM staff, attended the virtual meeting, including members of the public and representatives from InterWest Energy Alliance and the Southwest Energy Efficiency Project.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
Member of the Public:	What is GHG on Slide 8?	**Grid Modernization**
InterWest Energy Alliance:	A recent study shows that 97% of AMI (Advanced Metering Infrastructure) value is failing to meet its promises and there's a cite to a Utility Dive article. Is PNM proposing anything here that is different than 78% of utility customers that already have AMI meters?	**Grid Modernization**

InterWest Energy Alliance:	The grid mod statute includes a requirement to consider whether grid mod applications are "designed to support connection of New Mexico electrical grid into regional energy markets and increased New Mexico capability to supply regional energy needs through export of clean and renewable electricity" [according to] NMSA 62-8-13(B)(2). How will PNM's plan comply with this requirement?	**Grid Modernization**
Member of the Public:	Will the current grid need to be enlarged--or will distributed energy resources be reduced--or at least keep it at its current size?	**Grid Modernization**
Member of the Public:	How will the proposed system assure operations in situations when the grid or advanced system goes down, as in a storm situation?	**Grid Modernization**
Southwest Energy Efficiency Project:	Is PNM proposing to roll out dynamic pricing and load management programs as the AMI (Advanced Metering Infrastructure) meters are deployed to start collecting information?	**Grid Modernization**
InterWest Energy Alliance:	Thank you for the review of the RFI results. Very interesting. Are there technologies or projects that you expected to receive responses on but did not?	**Modeling**
Member of the Public:	Are the storage ponds [on the proposed project on Slide 22] open or covered?	**Modeling**

November 2, 2022, Technical Session #8

On November 2, 2022, PNM held the eighth in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP (Integrated Resource Plan). Representatives from Siemens presented a market forecast of natural gas, carbon emission prices, and capital costs they developed for PNM for the 2023 IRP. The presentation summarized the methodology as well as the assumptions used to derive the price forecasts covering the IRP's 2022-2043 planning period. Input included contributions from subject matter experts. internal analysis, and proprietary data.

Meeting Attendees

Twelve stakeholders, not including PNM and Siemens staff, attended the virtual meeting, including members of the public and representatives from InterWest Energy Alliance and rPlus, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
Member of the Public:	In the past, we've seen some basis differences between the New Mexico and Texas sides of the Permian, partly due to a lack of gas processing capacity in New Mexico and less pipeline takeaway capacity here. That trapped gas in New Mexico can help lower price for New Mexico utilities. Has that changed?	**Modeling**
InterWest Energy Alliance:	How has volatility been incorporated into gas forecast after winter storm Uri? Is there a method to backcast this methodology to test its accuracy?	**Modeling**
InterWest Energy Alliance:	Are the capital costs for the CT (Combustion Turbine) [reflective of a] 100% hydrogen capable turbine?	**Modeling**

rPlus:	Do the battery costs include total system cost, and do they include augmentation?	**Modeling**
rPlus:	How long a timeframe for project operation economic life will you use?	**Modeling**
Member of the Public:	Where in the futures and sensitivities models do you factor in the possibility of decentralization impacting on demand for PNM services?	**Modeling** **Grid Modernization** **Load &Energy Efficiency Forecasting**
Member of the Public:	Are you expecting any resistance to PNM's interest in getting information from behind the meter?	**Grid Modernization**

December 15, 2022, Technical Session #9

On December 15, 2022, PNM held the ninth in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP (Integrated Resource Plan). Representatives from Siemens presented their price forecast for the wholesale electricity market, and representatives from Itron presented their work on the load forecast. PNM's pricing department presented information on the assumptions and rate structures underlying PNM's plans for decarbonization, including the time-of-day pilot program.

Meeting Attendees

Forty-two stakeholders, not including PNM, Itron, and Siemens staff, attended the virtual meeting, including members of the public and representatives from InterWest Energy Alliance, New Mexico State University, Office of the New Mexico Attorney General, PNE USA, and Sandia National Laboratories, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
PNM	So, the on-peak non-solar hours, the reason that's higher, that's mainly due to the fact that those would be your morning ramp and your afternoon ramp prior entering the evening hours? Is that right?	**Modeling**
InterWest Energy Alliance:	This curve [Slide 14] to me does not show any penetration of storage. Is that correct?	**Modeling**
Sandia National Laboratories:	Does the Palo Verde [graph] on Slide 14 refer to the pricing at the Palo	**Modeling**

	Verde hub, or the price at the Palo Verde power plant?	
InterWest Energy Alliance:	My question goes back to your slide on your market drivers [Slide 11] and capital costs in particular. You mentioned a number of factors that you looked at on those cost assumptions and one of them was some preliminary assumptions on the IRA [Inflation Reduction Act]. I'm wondering if you can give us some more clarity or detail on what your assumptions were on the IRA. I understand the rules have not come out. It's early days for everyone but I'm wondering how you took that into account.	**Modeling**
Member of the Public:	I'm not quite following all that pricing that was just presented [Slide 11, in response to question from InterWest Energy Alliance on cost assumptions]. Could we get a slide or something to show that in the future?	**Modeling**
InterWest Energy Alliance:	I understand the curves here [Slide 11] don't reflect or include these PTC assumptions, but do you have a sense at this point how much [the IRA tax credits] will affect these price curves?	**Modeling**
Sandia National Laboratories:	Could you elaborate on the methodology used to obtain the hub pricing forecast? You mentioned that you did a capacity expansion model on the Western interconnect. Did you then run a nodal production cost model for each year, or the forecast obtained from the capacity expansion planning model?	**Modeling**
Member of the Public:	Will the hub prices change as the IRA [Inflation Reduction Act] credits are included?	**Modeling**

Sandia National Laboratories:	I have a question about the carbon price forecast. Could we flip back to [Slide 10]? The reference case forecast reflects a carbon policy starting in 2025. On the federal price, do you foresee any possibility that the incoming Congress will pass this, a federal CO2 price, or what exactly is the story that would explain a federal price going into effect in 2025?	**Modeling**
InterWest Energy Alliance:	In your trends that you're seeing--if you could go back to your high temperatures [Slide 26] -- I understand that's [an average] over 24 hours. But are you seeing an increase in daytime temperatures or are you seeing an increase in nighttime temperatures or are you seeing both or neither or a blend?	**Modeling**
Member of the Public:	Do the behind the meter PV numbers include community solar?	**Modeling**
InterWest Energy Alliance:	Looking at the nonresidential curve on that top graph [Slide 33], and it looks like you're assuming or forecasting that non residentials, which I assume include both commercial and industrial--kind of your medium commercial and your larger load customers--are going to be adopting some behind-the-meter generation, but not at the same rate as residentials, or not to the same extent. Is that the trend that you guys have been seeing so far that commercial and industrial customers don't want to use behind the meter so much, they just want to use more of PNM's system?	**Modeling**
Sandia National Laboratories:	Could we elaborate on the assumptions used for the increase in the residential solar and does this	**Modeling**

	assume full AMI [Advanced Metering Infrastructure] deployment?	
PNM:	Does this also assume that net metering is allowed to continue or is that an implicit assumption within the model, or is that not considered?	**Modeling**
Office of New Mexico Attorney General:	Does this electrification scenario [Slide 41] incorporate the new IRA [Inflation Reduction Act] tax credits and rebate programs?	**Modeling**
Sandia National Laboratories:	For this analysis on the rates [Slide 42], was it considered to be a voluntary or a mandatory time of use rate?	**Modeling**
InterWest Energy Alliance:	I'm seeing your numbers here [Slide 31] about your peak, your summer peak day being 2.6 degrees warmer, your winter peak day is 12.2 degrees colder. I'm going to reiterate my [previous] question [to be clearer.] For example, the summer peak day, being 2.6 degrees warmer – is that effect more from nighttime temperatures being warmer or daytime temps being warmer? And then same question for your winter peak day being 12.2 degrees colder. Is the larger contribution to that from nighttime temps being colder or daytime temps being colder? I understand what you're looking at is an average [Slide 29]. I'm just wondering--you may not have this information--but. in developing your average, were you able to notice or identify whether the contribution to the change in temperature is more from daytime or nighttime? I understand you might not have done the analysis. I'm just wondering if when you did, did you notice that at all?	**Modeling**

PNM:	On the modeling side [Slides 26-27], at least, you're calibrating 24 different hourly models to that daily average temperature. And so, I'm assuming, of course those are going to be statistically significant. So, you're, you're capturing the effects of the increasing daily temperature, whatever the daily temperatures are on an individual hourly basis. It's not like you're ignoring the hourly piece of it. And so, if you were to change this framework up and look at more hourly data on the temperature side, you'd be recalibrating each of those models and it probably is not going to change that relationship much. And when you do this, each time you reforecast a load, you're recalibrating to more current load/weather relationships. So, if there is a change in that relationship that's going to be captured within the calibration process before you reforecast.	**Modeling**
New Mexico State University:	As I'm reading it, the high PV [photovoltaic] scenario included 1,141 megawatts of total PV on the system [Slide 35]. Looking at the 2020 IRP most cost-effective portfolios (MCEPs), the no new combustion scenario, obviously that's the scenario that would end up with the most PV and that portfolio has 3,165 megawatt hours of solar. This doesn't line up in my mind that our high PV scenario from last time around [which] appears to be 3,165. You seem to have about one third as much solar in what you've modeled. So, maybe someone can explain this and if not, would you please do a scenario that matches what I expect	**Modeling**

	will come out again this time in the model?	
Sandia National Laboratories:	[On Slide 54] it seems like there's a lot of different variables there with different high, medium and low assumptions. And then there's probably even more. I guess you do have economic forecasts in there. So, I guess in general, there's a lot of variables with three different choices. So, it turns into a very large combinatorial problem. I was just curious if you could comment on the methodology for coming up with these different combinations. Was it based off of just going back and forth on what scenarios you think are critical and would have an effect on your IRP outcomes? Or was there some other kind of mathematical scenario reduction techniques out there? That might be getting too into the weeds here. When do you know when you feel comfortable with all these scenarios and how you book-ended them?	**Modeling**
Member of the Public:	Is the BTM [Behind the Meter] solar assumed to be mostly fixed-tilt?	**Modeling**
Sandia National Laboratories:	Can a residential customer participate in the pilot without having a smart meter installed?	**Modeling**
PNM	If you were a customer that had a behind-the-meter photovoltaic system, and you were getting a net metering benefit on the current residential 1A rate, would the value of net metering from BTM PV change as the time-of-day rates are implemented or if the customer enrolls in the TOD pricing structure?	**Modeling**

Member of the Public:	[How] might changes in usage patterns be included in the pilot as more people continue to work from home instead of going into a central workplace?	**Modeling**
Member of the Public:	I'm beginning to learn how your slides are working [referring to Slides 70-74], but, basically, "off peak" rates mean high peak, peaking renewable power/solar power generation. Do you think we could find another term so that we don't get the word "peak" used in different ways twice?	**Modeling**
Member of the Public:	As cost allocation will change, is some change in tax structure expected to make up for the government revenues that will be lost as we use less fossil fuels?	**Modeling**
Member of the Public:	[Asked relating to an earlier comment from Sandia National Laboratories regarding behind the meter solar and storage in Hawaii (Hawaii residential rate structure incentivizes storage paired with rooftop solar)]: Is the example of Hawaii indicating a move toward more fixed or variable rates?	**Modeling**
Sandia National Laboratories	Given the changes taking place at the PRC [Public Regulation Commission], when is your anticipated decision on the rate case filing and pilot proposal?	
InterWest Energy Alliance:	I [recall from a previous presentation] that PNM gets a lot of economic development inquiries that they turn away. How will your analysis and forecast take that into account? Do you plan to hold the public advisory meeting on this topic and identify how economic development opportunities may affect your forecast and needs?	**Modeling**

January 17, 2023, Technical Session #10

On January 17, 2023, PNM held the tenth in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP (Integrated Resource Plan).

AEG (Applied Energy Group) presented the results of its Energy Efficiency (EE) Market Potential Study that identified EE opportunities in PNM's service territory through 2042. The presentation included a detailed review of AEG's supply curve bundling analysis. Astrape Consultants presented the results of their ELCC study. The meeting also included highlights from PNM's energy efficiency programs and a PNM presentation of its promised post-summer 2022 review of new data and modeled market assistance for resource adequacy.

Meeting Attendees

Twenty-five stakeholders, not including PNM and contractors, attended the virtual meeting, including members of the public and representatives from InterWest Energy Alliance, NM RETA, and Sandia National Laboratories, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NM RETA:	Would electric vehicles [EVs] be a part of "miscellaneous" [Slide 14]?	**Load & Energy Efficiency Forecasting**
InterWest Energy Alliance:	Does this [Slide 14] include the IRA [Inflation Reduction Act] incentives, such as for heat pumps?	**Load & Energy Efficiency Forecasting**
NM RETA:	**On Slides 21 and 23, are the units in gigawatt hours as on Slide 22? What are the units there?**	**Load & Energy Efficiency Forecasting**
Sandia National Laboratories:	I'm curious to know what kind of measurement, verification, and evaluation [MV&E] PNM has done on	**Load & Energy Efficiency Forecasting**

	past energy efficiency programs, and if it has any plans for MV&E going forward?	
InterWest Energy Alliance:	Please describe why ELCC is used only for wind, solar, and storage. PJM's results from the recent winter storm Elliot in Texas and 2020's Texas winter storm Uri showed significant severe thermal outages during peak need times.	**Reliability-Resilience-Resource Adequacy**
NM RETA:	Is 650 megawatts of storage the recommended minimum for the PNM system to have operational by a certain year?	**Reliability-Resilience-Resource Adequacy**
Member of the Public:	How would PNM view independent solar, whether on individual, for example, a roof or DG context adding storage? What might those installations look like?	**Reliability-Resilience-Resource Adequacy**
InterWest Energy Alliance:	Is there a slide to show wind penetration to higher storage penetration?	**Reliability-Resilience-Resource Adequacy**
Member of the Public:	How much do the battery outage rates impact the study?	**Reliability-Resilience-Resource Adequacy**
Member of the Public:	Is there any point at which you lower [battery availability] well enough, wind becomes better for the system than solar?	**Reliability-Resilience-Resource Adequacy**
Member of the Public:	By adding significant amounts of solar, what's your level of curtailments?	**Reliability-Resilience-Resource Adequacy**
Member of the Public:	I thought that adding more solar to the system was detrimental to it, or at least more detrimental than adding wind and storage. But from this presentation, I'm hearing the exact opposite. And so, I'm trying to reconcile what has changed from my [previous] understanding of it.	**Reliability-Resilience-Resource Adequacy**
Member of the Public:	Did you assume that Four Corners was in the mix in 2025?	**Reliability-Resilience-Resource Adequacy**

NM RETA:	Regarding the difficulties in hours 18 and 20, is the forum for where PNM goes all in WECC or can SPP offer any assistance?	**Reliability-Resilience-Resource Adequacy**

February 15, 2023, Technical Session #11

On February 15, 2023, PNM held the 11th in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the IRP (Integrated Resource Plan).

The session, led by PNM's IRP director Nick Phillips, covered the following elements of the modeling framework: terminology; scenario screening with examples; modeled technologies versus RFP resources; RFI selections for Phase 1 modeling; the treatment of existing resources; economic development sensitivity cases; and IRP scenarios.

PNM IRP staff also demonstrated new features of the IRP website, including a Q&A section where stakeholders and others can assess responses to questions stakeholders raise at meetings.

Meeting Attendees

Twenty-five stakeholders, not including PNM and its contractors, attended the virtual meeting, including members of the public and representatives from CCAE, InterWest Energy Alliance, NM AREA, NMPRC, New Mexico State University, Onward Energy, SWEEP, and Synapse Energy for the New Mexico Attorney General, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NM AREA:	To make sure I'm understanding this right--this slide [Slide 11], which I think is helpful--what you're trying to do with Phase 1 is you've got … a large set of scenarios, and you want to try to … weed out the ones that are fairly clearly not going to perform well, such that it really wouldn't be efficient to go on running against all futures. So, if I understand right, what you're proposing to do on the screening is	**Modeling**

	that it would be a more limited set of futures. Is that kind of what you're proposing to do--basically run that first initial set of scenarios against the more limited set of futures to see what it produces and whether there's clearly some scenarios that are not worth pursuing because just the economics, or what have you, aren't working?	
NM AREA:	Does the company see this [Slide 14] more as something that the economics are showing has promise, or should be explored? Or do you foresee that there will be a reliability-based business case that really long-term storage of this nature might be necessary, or dispatchable resources in the alternative?	**Modeling**
CCAE:	Are you including identification of an additional or new demand-side resources like load shifting time of use rates, interruptible rates, demand response programs, and energy efficiency, as you identify the resource mix necessary to enable a carbon free system?	**Modeling**
CCAE:	This slide [Slide 15] refers to your RFI. Are any of the demand-side resources part of the RFI?	**Modeling**
Onward Energy:	You indicated Valencia, that you would be doing sensitivity modeling. In what context? Are you going to be doing that through the IRP process--is that something that's going to be included? I'd like to get a little more detail on what you mean by allowing that asset to retire or expire, and to allow a generic replacement to come in.	**Modeling**

Member of the Public:	My question was kind of generic in nature. I was just wondering what you're going to do about those southern resources. Also, [as] I understand [it] you really don't use much of the southern [New Mexico] resources in the northern part of your system. But you're going to have to do something about those also, aren't you--relative to going to zero carbon sometime in this timeframe?	**Modeling**
Member of the Public:	I ran across a recommendation about reviewing the reliability requirements for all the changes that are occurring, and considering inverter-based resources to maybe somehow be modified or the operation be modified to look at it and see if that can be used; and in response to operating reserves, which I think is going to impact, [that is] the change to renewables is certainly impacting the operating reserve and what you need to have. I'll send that report to you if you haven't looked at it.	**Modeling**
InterWest Energy Alliance:	Do you intend to file a notice on or before March 1 [2023] pursuant to the amended IRP procurement rule? Are you planning on filing the IRP on September 1 [2023]?	**Modeling**
InterWest Energy Alliance:	I'm wondering, how realistic do you think this more accelerated forecast [Slide 16] is compared to the stable forecast? I mean, are you seeing inquiries that you think may actually hold water, that may come to fruition? That leads you to believe that an accelerated forecast may be what actually comes to pass, and that's why you want to look at this kind of a scenario more seriously?	**Modeling**

NMPRC:	Do the generic resources modeled [Slide 16] have a location assigned with them due to the improbability of having any new transmission built to accommodate projects? I understand these generic resources to be placeholders. But is there an expectation that they are reasonable/possible that needs to be established?	**Modeling**
InterWest Energy Alliance:	Why not include a Phase 1 scenario base plus expanded solar, especially in the load pocket [Slide 17]?	**Modeling**
InterWest Energy Alliance:	Does this exclude the "least cost among all of the bids" with reasonable transmission expansion scenario [Slide 18]? I just wonder if you are: A) over emphasizing the cost of the new transmission, the transmission plus wind scenario, and B) not allowing the market to bring forth the best local mix of all, which we cannot predict through the scenarios, [and] which I feel is somewhat too narrowly focused.	**Modeling**
SWEEP:	Will the scenarios consider placing new resources at retired sites, like Four Corners or San Juan?	**Modeling**
New Mexico State University:	Have you excluded the flow battery technology which showed in the previous IRP?	**Modeling**
Synapse Energy for the New Mexico Attorney General:	What percent hydrogen fuel do you anticipate these new gas resources being converted to?	**Modeling**
InterWest Energy Alliance:	We are hoping the new rules provide more transparency about the least cost, least risk path options offered by the bids while protecting confidentiality because the projects	**Modeling**

	available in the market are hard to predict.	
NM AREA:	It sounds like, in these scenarios [Slide 23], the main one that would involve looking at transmission as part of it is the wind one. Is that pretty much right? Are there any others that you can see that where adding a transmission option as part of it would make a difference or would be useful?	**Modeling**
New Mexico State University:	Have you already covered the hydrogen fuel cost scenarios, or will it all come from electrolysis?	**Modeling**
Member of the Public:	How do you treat the electric energy needed for electrolysis?	**Modeling**
InterWest Energy Alliance:	My question follows up on [the question regarding the inclusion of transmission expansion]. [At Slide 22], I thought I heard you say that you were going to look also at, along with perhaps using the Luna and the other site that's in the south, that you would need to look at north/south transmission capacity expansion as part of that. And that's completely understandable. I'm assuming that, if you look at a base plus solar expansion, that you would similarly need to perhaps, depending on the geography, if you wanted to site solar, say, for example, in the south, where you might get better capacity factors and efficiencies and so on, you'd also need to look at transmission expansion on that north/south route. I'm wondering, why not look at this more holistically, so that you're not just saying base plus carbon capture, and we'll lump all the transmission costs into that? And then base plus	**Modeling**

	solar, will lump all the transmission costs into that? Why not look at it more holistically to see what benefits the north/south transmission expansion could provide you--with a diversity of resources, not just at your existing gas sites, but also add solar or a combination of things?	
Member of the Public:	What is the source of electricity for allowed electrolysis on site--solar or wind?	**Modeling**

March 15, 2023, Technical Session #12

On March 15, 2023, PNM held the 12th in the series of technical sessions for stakeholders devoted to discussing the advantages and disadvantages regarding the application of different technical methodologies within the modeling framework for the 2023 IRP (Integrated Resource Plan).

Participants were introduced to Gridworks, the nonprofit organization appointed by the New Mexico Public Regulatory Commission to lead the facilitated stakeholder process for the IRP. PNM's Public Advisory Process, begun on April 28, 2022, will transition into Gridworks' facilitated stakeholder process, beginning on June 15, 2023.

Gridworks provided an overview of the six-month, three-stage process, including: 1) Grounding (system requirements, resource options, and possibly load scenarios) and development of a statement of need; 2) Model runs by the Stakeholder Modeling Subgroup of its own models, engagement with PNM modelers, and development of action plans; and 3) Monthly IRP Reviews by all interested stakeholders to provide feedback on areas where PNM needs input.

The meeting also included a presentation by PNM IRP staff of PNM's modeling framework, featuring a demonstration of the steps involved in requesting modeling runs not already conducted by PNM.

Meeting Attendees

Twenty stakeholders, not including PNM staff, attended the virtual meeting, including members of the public and representatives from InterWest Energy Alliance, MISO, NM AREA, New Mexico State University, and SWEEP, among others.

Meeting slides can be found here.

Stakeholders raised the following questions.

Stakeholder Questions/Comments

Stakeholder	Question/Comment	Categories
NM AREA:	Will all the meetings be known all at once in advance? That would be very helpful.	**Facilitated Process**
Member of the Public:	I guess it's maybe too early in the process … but I don't see in this	**Facilitated Process**

	anything that's much different than a lot of things that we've been doing, or that you've been guiding us through. And so, maybe that's something that can become part of the conversation—how this differs from the way at least the process has been going this time round.	
NM AREA:	So, I guess what strikes me on this is that it kind of hits us cold. And in terms of, well, what does this mean? And we're getting asked questions like that. And to me, that's not very concrete to react to. And maybe it's partly because we've been involved with the process before; we're familiar to the general concept of what the statement of need is trying to say. I guess it's important to get input and particularly new input where maybe it hasn't come through before. But to really provide something constructive, we would really need at some point a straw man put together on statement of need by those that are most interested in contributing to the drafting of that straw man. It's my experience in facilitated processes that often makes the process move much more efficiently. Because once there's a straw man, it becomes clearer, at least to those who have different perspectives, whether there's something in there that gives them concern, or there's something missing that's giving them concern. But I … don't know what your process is going to be yet entirely. So, you very well may be envisioning something like that. I do want to provide feedback. We're kind of silent right now because it's	**Facilitated Process**

	very hard to react to this … just the statement of need and what's said here to us. To actually see a first shot at a straw man and have a statement of need allows us to really provide constructive comments. So, that's what I want to share. Hopefully, that's of help.	
SWEEP:	I was just curious about how far in advance would you expect agendas for the different tentative meetings to be available?	**Facilitated Process**
InterWest Energy Alliance:	I just wanted to say thank you to both [PNM and Gridworks]. This all sounds very interesting and very useful. So, we Look forward to participating in it going forward. I didn't want you to just think that your comments had fallen into a vacuum or something. There's not much for us to say at this point other than thanks. And we look forward to it going forward.	**Facilitated Process**
Member of the Public:	At this point, do you have a list of some of the additional stakeholders you might be bringing in? Will there be some sharing of that for those of us who've been with this process for a longer time?	**Facilitated Process**
SWEEP:	I just had a question mostly on … [Slides 20 and 21] How would different demand response futures be considered? Are we looking at it as a resource that could be competing against typical supply side? Or is this more of a key assumption like a forecasted modifier?	**Modeling**
New Mexico State University:	I just wanted to bring up your answer to my question about hydrogen prices. Was it that you're tracking hydrogen	**Modeling**

	prices as gas prices? So, it seems like the gas price does continue to be relevant.	
NM AREA:	I look at this IRP sensitivities [Slide 22], and you go from left to right, with the changes on the various assumptions, and I'm trying to compare this to the IRP core futures. It seems like you've got more categories, from left to right on the slide you've got up right now versus what you have from top to bottom, on the slide before on core futures [Slide 21]. I'm wondering, is there a version of this RFP sensitivity slide that can be made that essentially lays out the four core futures at the top of it, or something, just so that it's easy to see how the four core futures compare under all of the things from left to right versus the sensitivities?	**Modeling**
SWEEP:	Are the energy efficiency technology bundles documented in a prior slide deck?	**Modeling**

Gridworks Facilitated Stakeholder Process (March 28, 2023 - October 19, 2023)

March 28, 2023
Meeting #1: Orientation for PNM Integrated Resource Plan

Meeting Summary

Representatives from more than 42 organizations attended a stakeholder orientation meeting to discuss PNM's Integrated Resource Plan. The 80 participants were given the opportunity to share the topic that is most important to them related to the IRP. Topics included solar energy, distributed energy resources, battery storage, long-duration storage, modeling, transmission, interconnection, and public understanding of the IRP. The group was asked to identify missing voices who should be invited to participate. The list of meeting participants and their affiliations is attached.

The upcoming three-phase stakeholder engagement process was presented by Gridworks, the NMPRC-appointed facilitator for the required IRP stakeholder process. Phase 1 focuses on building a

shared foundation of knowledge and engaging diverse stakeholders to create a statement of need. Phase 2 will concentrate on modeling and developing actions that can meet the statement of need. Several stakeholders expressed interest in modeling activities and offered suggestions to consider on this topic. Phase 3 involves review and feedback on the IRP document. The role of stakeholders was presented and the plan for forming working groups was discussed.

The next meeting of the group is scheduled as an "in-person" workshop in Albuquerque on May 4 from 9 AM – 3 PM.

Questions, concerns, and suggestions are welcome through info@gridworks.org or by contacting Margie Tatro at mtatro@gridworks.org, 505-205-0838.

Additional Information

A recording of this meeting is available:
https://pnmresources.webex.com/pnmresources/ldr.php?RCID=8fc0f27d11b9fdb5baa8c87a56875ef9
password: MzsgnyA6

Materials related to this meeting are posted:
New Mexico Energy Planning – Gridworks,

(https://gridworks.org/initiatives/new-mexico-energy-planning/)

Materials include: the meeting invitation and meeting schedule, the presentation materials, the list of meeting participants, and a copy of the most current NMPRC rule regarding Integrated Resource Planning and associated Facilitated Stakeholder Process.

Information that has been prepared over the past year by PNM as a part of their IRP Public Advisory process can be found on the PNM IRP website: Meetings & Commentary (pnmforwardtogether.com),

(https://www.pnmforwardtogether.com/presentations).

Meeting Participants

(Note: unable to attend, but interested in participating is Jim DesJardins, Renewable Energy Industries Association)

Claire	ODonnell	AES
Patrick	Corrigan	AES
Skye	Mooney	AES
Rob	Refvik	BluWave-ai
Kevin	Cox	CDG Engineers
Parker	Cohn	CDG Engineers
Cameron	Brown	Clenera
Cara	Lynch	Coalition for Clean Affordable Energy
Barbara	Chatterjee	Community member
Athena	Christodoulou	Csol Power
Nick	Schlag	E3
Manfei	Wu	E3
Daren	Zigich	EMNRD, ECMD
Brett	Hooton	Escalante H2 Power
Sophie	Meyer	Form Energy
Avery	Dunn	Galehead Development
Amanda	Ormond	Gridworks
Deborah	Shields	Gridworks
Margie	Tatro	Gridworks
Alex	Pugh	Hecate Energy
Ed	Maddox	Innergex Renewables
Christopher	Leger	Interwest Energy Alliance
Lisa	Hickey	Interwest Energy Alliance
Anna	Hagel	Invenergy
Sam	Bernat	Invenergy

William	Consuegra	Invenergy
David	Simons	Itron
Brian	King	Kingzzzz Ranch
Keven	Gedko	New Mexico Attorney General
Ashley	Sgaliardich	Next Era Energy
Lindsay	Parker	Next Era Energy
Jim	Dauphinais	NM AREA
Kelly	Gould	NM AREA
Arthur	O'Donnell	NMPRC
Collin	Gillespie	NMPRC
Eli	LaSalle	NMPRC Utility Div
Brian	Johnson	NMRETA
Christopher	Hyer	NMRETA
Erik	Aaboe	NMRETA
Fengyu	Wang	NMSU
Glenn	Wikle	NMSU
Jeffrey	Spurgeon	Onward Energy
Chris	Stecklein	Pine Gate Renewables
Dugan	Marieb	Pine Gate Renewables
Rajat	Pungaliya	Pine Gate Renewables
Aaron	Braasch	PNM
Dean	Brunton	PNM
Don	Tarry	PNM
Emily	Gonzales	PNM
Erick	Seelinger	PNM
Hector	Dorbecker	PNM
Jeremy	Heslop	PNM
John	Verheul	PNM

Kelly-Renae	Huber	PNM
Kelsey	Martinez	PNM
Leslie	Padilla	PNM
Nicholas	Phillips	PNM
Sarah	Baxley	PNM
Thomas	Duane	PNM
Tohid	Khalili	PNM
Matthew	Shapiro	rPlus Hydro
Mike	Eisenfeld	San Juan Citizens Alliance
Len	Malczynski	Sandia National Laboratories
Marissa	Ballantine	Sandia National Laboratories
Walker	Olis	Sandia National Laboratories
Apollonia	Racca	Savion Energy
Cliff	Ho	Senator Heinrich's Office
Arnela	Smajlovic	Siemens
Blake	Mize	Siemens
Chelsea	LaRicci	Siemens
George	Bjelovuk	Siemens
Michael	Kenney	Southwest Energy Efficiency Project
Mayane	Barudin	Sovereign Energy
Keith	Herrmann	Stelzner Law Firm/Alb Bern Cty Water Utility Authority
Alondo	Regalado	Strategen
Jack	Smith	Synapse Energy
Shawna	Tillberg	Velarde & Yar, P.C.
Ari	Lackner	Vestas
Aaron	Gould	Western Resource Advocates
Brenda	Hazzard	Writers for Hire

May 4, 2023
Meeting #2: PNM Integrated Resource Plan Stakeholder Workshop

A stakeholder workshop to inform the PNM IRP was held on May 4, 2023, at the CNM Workforce Training Center in Albuquerque. It was attended by 55 people representing 32 organizations.

Workshop materials are available at the **Gridworks website:**

https://gridworks.org/initiatives/new-mexico-energy-planning/ Below is a summary of the workshop.

Purpose Of The Workshop

The **PURPOSE OF THE WORKSHOP** was to create a foundation of shared knowledge while providing opportunities for stakeholders to express their views, hear the views of others, and create input to the Integrated Resource Plan.

Key Outcomes

KEY OUTCOMES of the workshop were:

- tutorials regarding electric system planning requirements, available resources for meeting electric system requirements, and modeling;
- an outline for the statement of need; and
- identification of issues and concerns regarding modeling of utility portfolios.

Presentation materials and video recordings of the first two tutorial sessions are available via the

Gridworks website: https://gridworks.org/initiatives/new-mexico-energy-planning/:

- Statement of Need: System Needs and Requirements; video recording Session 1: https://youtu.be/EDaW4T_MDo0
- 2023 IRP Candidate Resources; video recording Session 2: https://youtu.be/3r_rm1u-g4M
- 2023 IRP: Modeling and Scenario Analysis Framework, Process Timeline and Scenario Run Requests

(FACILITATOR's NOTE: uninterrupted video recordings of the modeling tutorial and a presentation on modeling inputs will be available after May 9.)

Stakeholder Questions And Comments

STAKEHOLDER QUESTIONS AND COMMENTS were offered throughout the morning session. Topics included:

- How the IRP relates to the Renewable Portfolio Standards (RPS)
- RPS definitions could change to account for new technologies and alternative fuels
- Reliability of a carbon free grid; should it have the same reliability as the current grid?

- Resource Adequacy
- Synergistic effect of solar plus wind. How does Encompass software handle this?
- Effective Load Carrying Capability assumptions for individual resource types and combinations of resources.
- What risks does PNM perceive related to inverter-based resources
- Ground-source heat pumps
- Hydrogen and renewable natural gas – assumptions, availability, and emissions impacts
- Capital costs for resources (changes since last IRP)
- Life cycle costs for resources
- Technology readiness levels of resources
- Recommendation: summary table of technology readiness levels, costs, etc.
- Recommendation: summary table of initial scenarios and resources included
- Possible funding opportunities for demonstrations – explore the California Energy Commission model
- Transmission considerations: limited modeling in IRP; extent of transmission issues that limit the use of preferred resources
- Action plan term: 3 years per the rule, but longer-term view is also needed
- Need to understand resources in the pipeline now, additions and subtractions
- Clarification of demand-side resources assumptions

Written input offered by stakeholders before and during the meeting is listed below and is available on the Gridworks website.

Stakeholder	Document(s)	Topics
New Mexico Solar Energy Association	"Climate Action 2023-2033(1).pdf"	Superfast decarbonization Motivation
Sandia National Laboratories	"SAND Report, C. Ho.pdf"	Probabilistic Modeling of Climate Change Impacts on Renewable Energy Storage Requirements for NM's Energy Transition Act
Cynthia Mitchell	"v2 Mitchell Foundational Issues PNM 2023 IRP.pdf"	Consideration of wind solar, energy storage, demand response and energy efficiency

PNM in response to Barbara Chatterjee questions prior to March 28 meeting	"Amended IRP Rule (redlined).pdf" "Stakeholder Questions 2023054.pdf"	PNM and the IRP in general; changes to the IRP Rule
Interwest Energy Alliance	See below	Synergies between wind, solar and storage; modeling the reliability of fossil resources; market availability and transmission considerations



Working Group Outcomes

The **Statement of Need (SoN) Working Group** identified desired elements of the SoN and developed a preliminary outline. Five individuals (Cydney Beadles, Western Resource Advocates; Lindsay Parker, NextEra Energy Resources; Athena Christodoulou, CSol Power;, Abbas Akhil, Renewable Energy Ventures; and Nick Phillips, PNM) volunteered to edit the SoN outline for distribution to the full group by May 14 and presentation at the May 18 meeting. Volunteers are . (FACILITATOR'S NOTE: Amanda Ormond, from Gridworks, will assist this group, as needed.)

The **Modeling Working Group** learned about PNM's modeling framework and expressed concerns about the prior modeling efforts by PNM. Some stakeholders requested more information about the modeling efforts and the modeling engagement process/timeline. Two stakeholders submitted possible criteria for prioritizing additional model run requests and two stakeholders offered model run requests. The group suggested more structure for future conversations. Questions and suggestions were invited by mtatro@gridworks.org.

(FACILITATOR'S NOTE: We greatly appreciate the feedback and suggestions received. A more structured approach for the modeling efforts is being developed and will be offered for feedback prior to the May 18 meeting.)

Next Meeting

The next meeting of stakeholders is May 18 from 9:00 – 10:30 AM MDT via WEBEX. Please register by visiting the PNM IRP website, and click on "Register" for May 18:

Schedule & Registration (pnmforwardtogether.com)

https://www.pnmforwardtogether.com/schedule-and-events

Date	Topics / Presentation(s)	Register
May 4, 2023	Stakeholder Grounding Workshop for PNM Integrated Resource Plan (gridworks.org)	Register
May 18, 2023	IRP Stakeholder Meeting #3	Register

Announcements

The NM PRC is hosting a special open meeting at 9:00 AM on May 9, to share information on three important topics: community solar bid evaluations; greenhouse gas inventory and replacement resources tool; and hosting capacity analysis. For more information or to view the recording from this meeting, visit Live Open Meetings and Workshops - NM PRC (nm-prc.org)

The NM RETA is hosting a workshop on energy storage, including long duration, on Oct. 23-24. Contact Erik Aaboe at erik@nmreta.net for more information.

May 18, 2023
Meeting #3

Meeting Summary

Approximately 51 people attended the May 18 meeting of stakeholders to participate in advancing two primary work products: 1) input to the Statement of Need, and 2) modeling activities in support of input to the Action Plan.

A recording of the meeting is available at:

https://pnmresources.webex.com/pnmresources/ldr.php?RCID=1c9ae43ac5307f184ef31cf8054b4b11

password: JgJPCMA3

All meeting materials are available at: New Mexico Energy Planning – Gridworks. Documents found there are: the meeting agenda, this meeting summary, a recording of the meeting, and the following

read-ahead materials:

- **Slide deck – Gridworks IRP 5/18/23 Stakeholder Engagement Meeting**
- **PNM Confidentiality Agreement 2023 IRP Stakeholder Facilitated Process**
- **Modeling Topics Collected to Date V1, 5/12/23**
- **Proposed Structure for Modeling Working Group**
- **PNM IRP Statement of Need**

Participants attending for the first time were invited to provide their name, organization, and top interest related to the IRP. (Note: this information along with input offered previously by stakeholders is summarized in a document entitled "STAKEHOLDER INTERESTS PNM IRP" which will be loaded on New Mexico Energy Planning – Gridworks under the "OVERVIEW" section.)

Statement of Need

An outline for the Statement of Need, which was started during Meeting #2 (May 4) and developed by a group of volunteers over the past two weeks, was summarized by Abbas Akhil. Contributors to the outline, in addition to Abbas, were Daren Zigich, Athena Christodoulou, Cydney Beadles, and Lindsay Parker. Comments regarding the outline were offered by participants and are captured in the SoN document posted above. A group of volunteers offered to add content between now and the next meeting (June 1). This group includes Abbas, Athena, Daren as well as Barbara Chatterjee, Michael Kenney, Michael Barrio, and Cara Lynch. Nick Phillips is also a member of this group. The goal is to share the SoN with all stakeholders for a June 15 discussion regarding the degree of consensus.

Modeling Engagement Plan

Key components of the "Proposed Structure for the Modeling Working Group" (which was available as a read-ahead) were reviewed. The formation of a modeling core team, its functions and membership were discussed. Meeting participants suggested modifications to the membership list.

modifications to the plan, including a revised core team, can be found at the link above.) Comments regarding the draft plan are to be submitted to mtatro@gridworks.org, as soon as possible.

Important milestones related to modeling activities include:

May 26 – all interested stakeholders to provide model run requests and model run prioritization criteria to mtatro@gridworks.org. The modeling core team will consider this information and present recommended criteria to the entire stakeholder group on June 1.

June 15 – latest date for stakeholders to request data (either publicly available data set or, with a signed NDA, a proprietary data set). Core team presents prioritized (additional) model run requests to entire stakeholder group on June 15. (Note: the PNM Confidentiality Agreement, or "NDA", is available in the read-ahead materials listed above.)

June 29 – day-long in-person modeling workshop/Meeting #6, in Albuquerque

Closing and Next Steps

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. A feedback survey has been implemented for this and future meetings. Please complete this very short survey using one of the following mechanisms: Visiting this link: bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here

NEXT MEETING: Thursday, June 1

TIME: 9:00 – 10:30 AM

WHERE: WEBEX. Please register via the PNM IRP Website

Schedule & Registration (pnmforwardtogether.com); or
http://www.pnmforwardtogether.com/schedule-and-events

June 1, 2023
Meeting #4

Meeting Summary

Approximately 57 people attended the June 1, 2023, meeting of stakeholders to advance two primary work products: 1) Statement of Need, and 2) modeling activities in support of input to the Action Plan.

A recording of the meeting is available at: IRP Stakeholder Meeting #4 (June 1)-20230601 1500-1
Passcode: CiEmj4Wb

All meeting materials are available at: New Mexico Energy Planning – Gridworks.

Documents found at the above link include the meeting agenda, this meeting summary, a recording of the meeting, and the following materials:

- **Slide Deck – Gridworks IRP 6/1/23 Stakeholder Engagement Meeting**
- **PNM IRP Statement of Need Outline – updated 5/31/23**
- **"Probabilistic Modeling for NM's Energy Transition Act, ASME Conference on Energy Sustainability"**
- **Slide Deck – Update from Modeling Core Group – 6/1/23**

Participants attending for the first time were invited to provide their name, organization, and top interest related to the IRP. (Note: interests by stakeholders are summarized in the document entitled "STAKEHOLDER INTERESTS PNM IRP." It is loaded on New Mexico Energy Planning – Gridworks under the "OVERVIEW" section.)

Statement of Need Update

Working group members provided an update on the Statement of Need document (see above link). Michael Barrio described the status of the document and asked other working group members to comment on sections they contributed. Abbas Akhil, Daren Zigich, Athena Christodoulou, Barbara Chatterjee, Michael Kenney, Cara Lynch, and Nick Phillips provided input to the document. A new section entitled "Determination of the Resource Portfolio" (as defined in the IRP rule, Appendix A) offers an opportunity for stakeholders to provide input regarding the criteria and weighting for evaluation of the most cost effective portfolio.

ACTON REQUESTS: We are seeking one person to serve as a co-lead with Michael Barrio over the next month. Please contact Michael B. if you are willing to assist. Comments on the SoN can also be sent to him at email: mbarrio@advancedenergyunited.org, office: 202.380.1950 3053, mobile: 310.869.5311

NEXT STEPS: The working group, led by Michael B. and supported by Amanda Ormond, will be incorporating material offered to date and will prepare an updated document for stakeholders to review

before the June 15 meeting. All stakeholders will be asked to indicate their degree of support for the document during the June 29 meeting.

Modeling Update

The modeling core team, represented by Aaron Gould and Nick Phillips, provided an update on a list of modeling run requests received to date along with the relative level of complexity of each request. This list is shown below:

Scenario description	Complexity/time to develop
Future CTP with high EV & High Building Electrification	Low
Future CTP with increased DR	Low/Medium
Extensions for Valencia and/or Reeves	Low*
FCPP through 2027/2031	Low
No combustion scenario post 2039 - Include: Solar, Wind, Li-ion storage, Long duration storage, wind expansion, geothermal as candidate options	Medium
No New Combustion with Thermal Storage	Medium
Accelerated Carbon Free (2030, 2035)	Medium
Complex Scenario – Transmission Expansion + Many Alternative Resources	Medium
Gas Price (High/Very High)	Low/Medium
More Extreme Weather Sensitivities	High
WRAP / RTO modeling	High
Correlated Gas Outages	High

The team suggested establishing a tracking system for questions and answers and this suggestion is being considered by the Gridworks team.

The types of modeling information included in the public and the confidential datasets were summarized.

ACTION REQUEST: June 15 is the latest date for stakeholders to request access to the information. Requests can be made in a short email to Nicholas.Phillips@pnm.com, IRP@pnm.com, and mtatro@gridworks.com

NEXT STEPS: The modeling core team will schedule a meeting with requestors to clarify and refine the scope of the proposed analyses such that a recommendation can be considered by the full stakeholder group on June 15. During this same meeting PNM will share initial modeling results from Phase 1 and 2 runs.

The June 29 workshop (9 am – 5 pm) will include more detailed discussions of modeling results to date as well as upcoming modeling efforts.

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. A feedback survey has been implemented for this and future meetings. Please complete this very short survey using one of the following mechanisms: Visiting this link: bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here

NEXT MEETING: Thursday, June 15 TIME: 9:00 – 10:30 AM

WHERE: WEBEX. Please register via the PNM IRP Website Schedule & Registration (pnmforwardtogether.com); or https://www.pnmforwardtogether.com/schedule-and-events

June 15, 2023
Meeting #5

Meeting Summary

Approximately 60 people attended the June 15, 2023, meeting of stakeholders to advance two primary work products: 1) input to the Statement of Need, and 2) modeling activities in support of input to the Action Plan.

A recording of the meeting is available at:
https://pnmresources.webex.com/pnmresources/ldr.php?RCID=e844494a3b440307b4870f908ab117fe
PW: EqBCpnF5

All meeting materials are available at: New Mexico Energy Planning – Gridworks or https://gridworks.org/initiatives/new-mexico-energy-planning/

Documents found at the above link include this meeting summary, a recording of the meeting, and the following materials:

- **Slide Deck – Gridworks IRP 6/15/23 Stakeholder Engagement Meeting**
- **Slide Deck – PNM 2023-2042 IRP: Initial Modeling Results v2**
- **Statement of Need – 6/14/23**

In addition, the summary of stakeholder-requested modeling runs is posted on the same website, see

2023.06.15 Modeling run requests V6

Announcements

Clarification on the IRP action plan term and planning horizon were issued by the NM RPC on June 2, 2023. This clarification can be reviewed here: **NMPRC Guidance Letter June 2, 2023**.

Per a stakeholder request, a process has been established for managing questions arising in the remaining months of the facilitated stakeholder process. See **Q&A Management System Established, June 2, 2023**.

June 15 is the last date for stakeholders to request access to the public or confidential modeling information.

Statement of Need Update

Michael Barrio described the status of the Statement of Need input document (see link above) and reviewed the issues where questions remain and discussion is needed. Several stakeholders offered comments and suggestions which will be addressed. He thanked those who have contributed input to date. Anyone interested in continuing to refine this document is invited to attend a working session on Monday, June 19 from 4-5 PM MDT. See the invitation below:

Topic: PNM IRP Work Session, via Zoom, hosted by Michael Barrio https://advancedenergyunited-org.zoom.us/j/4795587885 Meeting ID: 479 558 7885

One tap mobile

+16694449171,,4795587885# US

+16699006833,,4795587885# US (San Jose)

The working group, led by Michael and supported by Amanda Ormond, is seeking additional materials to complete outlined sections of the SoN. A new draft will be posted (Gridworks.org website) for stakeholders to review by June 23. All stakeholders will be asked to indicate their degree of support for the document during the June 29 meeting.

Modeling Update

The PNM team provided an update on preliminary modeling results to date. Outputs from these runs have been posted on VENUE so stakeholders who have requested access to the public or confidential data are welcome to review the information. A "DEEP DIVE" briefing on the results is also being held on Wed., June 21 from 1-5 PM via WEBEX. If you have not received an invitation and wish to attend, please contact IRP@pnm.com. A recording of the meeting will be posted on the Gridworks.org website.

A discussion regarding the complexities of the federal Inflation Reduction Act as it impacts IRP planning prompted a stakeholder to offer a resource on this topic: "How the Inflation Reduction Act Can Transform Utility Resource Planning," https://info.advancedenergyunited.org/ira_webinar_june2023

The June 29 workshop (9 am – 5 pm) will include more detailed discussions of modeling results to date (by both PNM and others) as well as upcoming modeling efforts.

July 13 is the last date for stakeholders to notify Gridworks (mtatro@gridworks.org) of their desire to share insights and observations from their own modeling efforts. Form Energy will be presenting during the June 29 meeting.

Twelve stakeholder-requested modeling runs have been defined thanks to intense dialogue among stakeholders over the past two weeks. A summary of the runs can be found here: **2023.06.15 Modeling run requests V6**.

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. A feedback survey has been implemented for this and future meetings. Please complete this very short survey using one of the following mechanisms: Visiting this link: bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here

NEXT MEETING: Thursday, June 29

TIME: 9 AM – 3 PM, including lunch (provided) WHERE: CNM Workforce Training Center, Albuquerque

RSVP: to Deborah Shields, dshields@gridworks.org by 5 PM (MDT), June 22

June 29, 2023
Meeting #6

Meeting Summary

Approximately 32 stakeholders attended the June 29, 2023, meeting held in person in Albuquerque.

Recordings of the meeting sessions are available at:

I. Welcome, Gridworks https://youtu.be/EteZD-_vXPY

II. Statement of Need https://youtu.be/zR-swyF0oRU

III. Modeling Insights and Observations, Form Energy https://youtu.be/sPC61a7HOXc

IV. Modeling Results and Factors, PNM https://youtu.be/7mJLbRaERB0

V. Next Steps, Gridworks https://youtu.be/u0kLokIOyK4

Additional materials are posted at New Mexico Energy Planning – Gridworks or https://gridworks.org/initiatives/new-mexico-energy-planning/. Below is a list of available documents:

- **Workshop Agenda**
- **Slide Deck – Gridworks 6/29/23 Stakeholder Workshop**
- **Slide Deck – PNM 2023-2042 IRP: Modeling Results Update**
- **Slide Deck – Form Energy: Modeling best practices in a decarbonized future**
- **SoN Outline V2 – 6/26/23**
- **SoN Parking Lot – 6/29/23**
- **SoN Input from 6/29/23 Stakeholder Meeting**

Meeting Purpose, Outcomes, and Announcements

The purpose of the meeting was to prepare stakeholders to provide input to the Action Plan by August. Key outcomes of the meeting were:

- Input on Statement of Need
- Review of modeling results to date
- Awareness of "APPENDIX A factors" to consider in evaluating resource portfolios
- Candidate action plan ideas that are independent of modeling results

Two schedule changes were announced:

1. July 13 meeting has been moved to July 27 from 9 AM-12 NOON via WEBEX.
2. Aug 17 meeting has been extended. It is now scheduled for 9 AM -12 NOON via WEBEX.

Statement of Need Update

Michael Barrio presented the status of the Statement of Need input document (**SoN Outline V2 – 6/26/23**) and stakeholder comments were offered as feedback. Input offered during the meeting is summarized in **SoN Input from 6/39/23 Stakeholder Meeting.**

The working group, led by Michael and supported by Amanda Ormond, will be incorporating material offered to date and will prepare an updated document (to be posted on the Gridworks.org website) for stakeholders to review before the July 27 meeting. A working group call will be scheduled in advance of the meeting on July 27. Stakeholder consensus will be assessed during the July 27 meeting.

Stakeholder Modeling Observations

Kailash Raman, Form Energy, shared insights derived from a review of the PNM IRP public data set. Suggestions for future modeling techniques, including using an 8670-hour optimization method and incorporating multi-weather year analysis, were recommended for characterizing the decarbonized grid of the future. See **Slide Deck – Form Energy: Modeling best practices in a decarbonized future.** The treatment of energy storage resources in modeling was discussed by the group as being very important.

Note: July 13 is the last date for stakeholders to notify Gridworks (mtatro@gridworks.org) of their desire to share insights and observations from their own modeling efforts.

Modeling Update

The PNM team provided an update on preliminary modeling results to date, including initial results from several stakeholder-requested runs. Outputs from these runs have been posted on VENUE and stakeholders who have requested access to the public or confidential data are welcome to review the information. The team also shared a preliminary set of criteria (factors and weights) used to rank order the portfolios analyzed to date. Following the modeling results overview, members of the modeling core team led the modeling deep-dive discussion using questions submitted by all meeting attendees. The PNM team shared model result details on many topics including energy efficiency, demand response, hydrogen assumptions and risks, and carbon emissions. Attendees also discussed carbon capture, weather years, wind and transmission implications, regional market influences, and load changes possible through customer engagement. Members of the modeling core team in attendance, Aaron

Gould, Kailash Raman, Cynthia Mitchell, Ed Rilkoff and Marissa Ballantine, were thanked for their leadership and insights.

Recommended Portfolio Factor and Weights

A brief discussion was held introducing factors to consider when selecting resource portfolios and the language in the IRP rule (via Appendix A) that utilities must consider resulted in the following comments from stakeholders:

- PNM noted - Additional reliability factors will be added by PNM in its third phase of modeling such as Expected Unserved Energy (EUE), Loss of Lode Event (LOLE), Peak Load Shed, and Loss of Load Hours
- Costs vary among different futures
- Technical readiness is a subjective criteria
- Diversity has two components- technology diversification (e.g.,types of storage) and fuel diversity
- Need consideration of secondary carbon effects – upstream (cradle to grave)
- End of life costs – ensuring it is included in utility costs, not passed on to society
- Drought impact on hydro, Palo Verde cooling water, etc.
    - Water use and availability
- Net Present Value portfolio (not with weighted factor)
- Value of scalability relates to load forecasting and should not be a weighting factor
- Too many points given to reliability because models already solve/screen for reliability
- What is reliability expectation for a carbon-free resource future (& climate change)
- Climate justice (replacing fossil peakers with storage)
- NIMBY
- Action plan needs to add an item to address location of replacement resources (e.g. justice)
- There is value in downward flexibility (ramping down generation, when needed), in addition to upward flexibility

Action Plan Suggestions

Three candidate action plan ideas that are not related to modeling, were collected during the meeting in the “coffee break” area. These are shown below:

- Changing fossil fuel plants to LDES as environmental justice for impacted communities
- Collect distribution feeder level reliability metrics to understand reliability equity

- Initiate public education effort regarding electricity sector changes and IRP process

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. Gridworks appreciates the 10 people who completed the survey during the meeting. Others are encouraged to complete the survey by visiting this link:

bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here

NEXT MEETING: Thursday, July 27 TIME: 9 AM – 12 NOON

WHERE: WEBEX

REGISTER: Registration (pnmforwardtogether.com), click on the July 27 "REGISTER" box in the meeting schedule table

July 27, 2023
Meeting #7

Meeting Summary

Approximately 43 stakeholders representing 28 different organizations attended the July 27, 2023, meeting via WEBEX.

Meeting materials are posted at New Mexico Energy Planning – Gridworks or https://gridworks.org/initiatives/new-mexico-energy-planning/. Below is a list of available materials, including a recording of the meeting:

- SoN Outline V4-7/28/23
- Meeting Agenda
- Video Recording – IRP Stakeholder Meeting #7 (7/27/23); Password: qDdmUHM6
- Slide Deck – Gridworks IRP 7/27/23 Stakeholder Engagement Meeting
- Slide Deck – PNM Modeling Results and Scoring Phases 1-2v3-1-1 7/28/23

Meeting Purpose, Outcomes, and Announcements

The purpose of the meeting was to prepare stakeholders to provide input to the Action Plan in August and September. Key outcomes of the meeting were:

- Stakeholder understanding of modeling results to date
- Review status of input to Statement of Need
- Stakeholder priority for portfolio screening criteria

The August 17 meeting has been moved to Aug. 31 and will begin at 8:30 AM. It is now scheduled for 8:30 AM -12:30 PM **via WEBEX.**

Update on 2026 RFP Results

Nick Phillips presented an overview of results of the RFP for new resources to come online in 2026. Contract negotiations are underway for 310 MW of new 4-hr battery storage and 100 MW of new solar. The structure of the financial arrangements and regulatory approval are important next steps in moving forward, as battery assets will be treated as leases.

Modeling Update

The PNM team provided an update on preliminary modeling results to date, including initial results from several stakeholder-requested runs (Four Corners PP abandonment sensitivities and increased demand response scenarios). The team also shared a revised set of criteria (factors and weights) used to rank order the portfolios analyzed to date. A question and answer session followed. Questions not addressed during this discussion will be answered and posted in the Q&A database for the facilitated stakeholder process: 2023 IRP Facilitated Stakeholder Process Q&A (pnmforwardtogether.com)

The team will now enter phase 3 of the modeling work, including sensitivity analyses within the production cost modeling (via ENCOMPASS) and the SERVM based reliability and resiliency analyses.

Statement of Need Update

Michael Barrio presented the status of the Statement of Need input document. The working group is making good progress on the document and will prepare a final version for stakeholder review prior to the Aug. 31 meeting. The current version of the document ("SoN Outline V4 - 7/28/23") is posted on the Gridworks.org website.

Priority Needs

A "STAKEHOLDER PRIORITY NEEDS" survey instrument was completed by stakeholders before and during the meeting. This information is being provided (without attribution) to the utility to convey the priority needs of stakeholders. Results of the valid responses are shown below:

PRIORITY NEEDS SURVEY RESULTS (14 VALID RESPONSES)*

NUMBER OF PEOPLE LISTING THE NEED AS PRIORITY	NEED
12	Reliability and Resiliency
10	Affordability (life cycle cost of portfolio)
8	Environmental Attributes (e.g. water use, air quality) + non carbon emissions
7	Exceeding State Carbon Reduction Requirements
7	Climate Justice/Energy Justice
6	Fuel Diversity and Fuel Security
5	Exceeding State RE Requirements

5	Maximizing EE, Demand Response and DSM Technology
4	Scalability of Technology
3	Technology Diversity
2	Research & Demonstration of New Technology
1 – OTHER, WRITE IN	Minimizing future reliance on fossil fuels and stranded costs of fossil fuel infrastructure

* Responses that included more than 5 priority needs are not included in this summary. as they are considered as invalid. Respondents in this category were given the opportunity to redo their input and several did so.

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. Gridworks appreciates those who completed the survey during the meeting. Others are encouraged to complete the survey by visiting this link:

bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here

NEXT MEETING: Thursday, August 31

TIME: 8:30 AM – 12:30 PM NOON – NOTE MEETING START TIME WHERE: WEBEX

REGISTER: Schedule & Registration (pnmforwardtogether.com), click on the August 31 "REGISTER" box in the meeting schedule table.

August 31, 2023
Meeting #8

Meeting Summary

Approximately 30 stakeholders representing 22 different organizations attended the Aug 31, 2023, meeting via WEBEX.

A recording of the meeting is available at:
https://pnmresources.webex.com/pnmresources/ldr.php?RCID=ce897ca1790007f769fe120429e00289
PW: mXbauP9a

The recording of the supplemental Q&A session, held from 1-2 PM this same day, is available at:
https://pnmresources.webex.com/pnmresources/ldr.php?RCID=be18888a0a15703e33770f891265d4f6
PW: PmSt3Mg2

Meeting materials are posted at New Mexico Energy Planning – Gridworks or
https://gridworks.org/initiatives/new-mexico-energy-planning/

- **Slide Deck – Gridworks IRP Stakeholder Meeting #8 – 8/31/23**
- **Slide Deck – PNM 2023-2042 IRP: Modeling Results Update – 8/31/23**
- **PNM SoN final draft – 8/28/23**

Meeting Purpose, Outcomes, and Announcements

The purpose of the meeting was to begin drafting stakeholder input to the action plan. Key meeting outcomes were:

- Review and seek input to the Statement of Need and priority needs
- Create stakeholder understanding of modeling results
- Begin collection of suggestions for Action Plan

Statement of Need Update

Michael Barrio reviewed the stakeholder input to the Statement of Need (SoN). The document ("PNM IRP SoN_final draft 8.28.23.docx (gridworks.org)") is posted on the Gridworks.org website. Appreciation was expressed for the work by the working group members: Athena Christodoulou, Barbara Chatterjee, Daren Zigich, Michael Kenney, Cydney Beadles, Jim DesJardins, and Chadette Pfaff. Stakeholders suggested that geothermal energy be added to the list of considered resources. (Note that a workshop on ADVANCING GEOTHERMAL DEVELOPMENT IN NEW MEXICO is being held at New Mexico Tech on

Sept. 21, 2023. For more information, contact shari.kelley@nmt.edu or tasolomon6@gmail.com.) The SoN also includes a list of Items for Future Discussion.

The group was reminded of the results of the "STAKEHOLDER PRIORITY NEEDS" survey deployed during the last meeting. PNM provided a refresher on the SoN and Action Plan requirements in the IRP rule and shared a template/outline of their SoN.

Modeling Update

The PNM team provided an update on phase 3 of the modeling. Thirty-four different portfolios were modeled and ranked based on cost, technology risk, and carbon emissions. All portfolios satisfied initial reliability requirements. The group discussed the selection of portfolios that advanced to phase 3 of modeling. Given the interest in "Green Hydrogen", a stakeholder suggested that a portfolio inclusive of this technology be considered as part of phase 3. Five scenarios (each with a set of resource/technology options) underwent SERVM-enabled reliability checks and received resource adjustments to optimize reliability metrics of LOLE and EUE.

Key observations from the modeling are shown below:



The PNM modeling team will be completing several modeling tasks to inform the best path forward for the most cost-effective portfolio.

Note: A supplemental Q&A session regarding modeling results was held from 1-2 PM this same day to answer technical questions on the modeling.

Action Plan Discussion

Action plan suggestions offered throughout the 2023 IRP stakeholder meetings are shown below:

- Changing fossil fuel plants to long duration energy storage as environmental justice for impacted communities
- Collect distribution feeder level reliability metrics to understand reliability equity
- Initiate public education effort regarding electricity sector changes and IRP process
- Explore availability of landfill gas as supplementary/replacement fuel
- Include extreme weather considerations during next IRP cycle
- Explore benefits from participation in organized regional market, and from participation under extreme weather scenarios
- Incorporate consideration of correlated gas outages in next IRP cycle

PNM shared the list of actions that were included in the prior (2020) IRP.

Stakeholders are invited to submit action plan suggestions **by noon on Sept. 13**, per the following process:

- Submit suggestions via a form available at: https://forms.gle/hvJUPZGCrpjXn8vs6 Note that name, organization and email are required. Multiple submissions are allowed.
- Those who are unable to access google docs, send an email with "PNM ACTION PLAN SUGGESTION" in the email subject to info@gridworks.org by noon on Sept 13. Please include your suggestions, your name, and your organization.
- Discussion of ideas will be the foundation for the Sept. 14 meeting.

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. Gridworks appreciates those who completed the survey during the meeting. Others are encouraged to complete the survey by visiting this link:

bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here 

NEXT MEETING: Thursday, Sept 14 TIME: 9:00 – 10:30 AM

WHERE: WEBEX

REGISTER: Schedule & Registration (pnmforwardtogether.com), click on the September 14 "REGISTER" box in the meeting schedule table.

September 28, 2023
Meeting #9

Meeting Summary

Approximately 34 stakeholders representing 25 different organizations attended the Sept. 28, 2023, meeting via WEBEX.

A recording of the meeting is available at: IRP Stakeholder Meeting #9 (Sept 28)-20230928 1458-1 with password: YmN9KAkV

Meeting materials are posted at New Mexico Energy Planning – Gridworks or https://gridworks.org/initiatives/new-mexico-energy-planning/

- **Slide Deck – PNM 2023-2042 IRP: Modeling Results Update – 9/28/23**
- **Slide Deck – Gridworks IRP Stakeholder Meeting #9**
- **Stakeholder SoN Compared to PNM 2023 IRP Outline**
- **PNM SoN Skeleton – 9/14/23**
- **Stakeholder SoN final draft – 8/28/23**
- **DRAFT #2 – PNM Action Plan Mapping Worksheet**

Meeting Purpose, Outcomes, and Announcements

The purpose of the meeting was to develop stakeholder input to the action plan. Key meeting outcomes were:

- Review input to the Statement of Need and priority needs
- Create stakeholder understanding of modeling results
- Begin collection of suggestions for the Action Plan

Modeling Update

The PNM team provided an update on results of the stakeholder requested modeling runs as well as the following sensitivities:

1. **10-yr Expiration of Tax Credits (ITC and PTC)**
    - Assume no ITC or PTC for applicable resources added after 2035
2. **TOU (Time Of Use) Rates**
    - Introduce residential TOU pilot rates in 2025 and full programs beginning 2030

- On-peak 5-8am and 5-8pm
- Whole house EV Rate (10pm-5am)
- Assume 20% opt-out and 80% use TOU

3. **DERMS (Distributed Energy Resources Management System)**
    - Assumes TOU rate structure embedded in load forecast
    - Assumed 25% of PV-DG customers installed customer sited Battery Energy Storage System (BESS) to be controlled by PNM for system benefits

Resiliency (SERVM model) runs are still in process and will be provided for the Oct. 19 meeting.

Statement of Need

The PNM team reviewed a table outlining where stakeholder input to the SoN is being addressed in the IRP. A detailed map of the same information and a skeleton text version of PNM's SoN were distributed prior to the meeting.

The PNM team presented graphs to show the estimated new capacity additions for three timeframes: now-2028, 2028-2032, and 2033-2040. Resources are grouped into three types: low-cost carbon-free energy resources, dynamic balancing resources, and firm resources.

Stakeholders were asked to comment on the reasonableness of the projected quantities and types of new capacity needs appropriate for the timeframes. Stakeholders were asked to submit concerns or lack of agreement with the capacities and types of resources needed via one of three options:

1. During this meeting;
2. by 12 NOON on Oct. 5 via email to info@gridworks.org; or
3. in person at a WebEx meeting from 9:00 -10:00 AM on Oct. 6.

Action Plan Discussion

Stakeholders' suggested Action Plan items and items being considered by PNM were presented. They are included in the Gridworks slide deck (see link above). Gridworks has created a framework to provide information on items that are of interest to both the utility and stakeholders. See the worksheet, DRAFT #2 – PNM Action Plan Mapping Worksheet.

Stakeholders were asked to comment on the action plan items through one of three options:

1. During this meeting;
2. by 12 NOON on Oct. 5 via email to info@gridworks.org; or

3. in person at a WebEx meeting from 9:00 -10:00 AM on Oct. 6.

Next Steps

If stakeholders have concerns or do not agree with the capacities and types of resources needed in the SoN, and/or if stakeholders have comments regarding the proposed action plan items, there are two options for getting this input incorporated into the facilitated stakeholder process. These options are to:

- **send an email to info@gridworks.org by 12 NOON on Oct. 5, or**
- **attend an optional WebEx meeting from 9:00 -10:00 AM on Oct. 6. to submit concerns and comments on SoN and Action Plan**

Key Dates

- Oct. 6, 9:00 - 10:00 AM WEBEX Meeting - Optional meeting to submit comments on SoN and Action Plan
- Oct. 19, 9:00 – 10:30 AM WEBEX Meeting – Update on SoN and Action Plan by PNM

To register for the above meetings please go to

https://www.pnmforwardtogether.com/schedule-and-events. You will see the WEBEX meetings listed; please click on "REGISTER" to be added to the meeting.

- Dec. 15 - IRP is filed by PNM
- Dec. 19, 9:00 - 10:30 AM WEBEX Meeting - Final stakeholder meeting to collect input regarding how you experienced the process
- Jan. 31, 2024 - Gridworks' report is delivered to the NM PRC. The report will include the results of both NM IRP Facilitated Stakeholder Processes (PNM and SPS).

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions as we move forward together in this new process. Gridworks appreciates those who completed the survey during the meeting. Others are encouraged to complete the survey by visiting this link:

bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here.



October 19, 2023
Meeting #10

Meeting Summary

Approximately 22 stakeholders representing 17 different organizations attended the Oct. 19, 2023, meeting via WEBEX. In addition, representatives from PNM, their consultants, and Gridworks were also in attendance.

A recording of the meeting is available at: IRP Stakeholder Meeting #10 (Oct 19)-20231019 1500-1,

password is: MiMAjh7K

Meeting materials are posted at New Mexico Energy Planning – Gridworks or https://gridworks.org/initiatives/new-mexico-energy-planning/

- **Slide Deck -PNM 2023-2042 IRP: Modeling Results Update, Statement of Need, and Action Plan – 10/19/23**
- **PNM IRP Statement of Need – DRAFT – 10/17/23**
- **PNM Action Plan DRAFT 2023 IRP – 10/17/23**
- **PNM Action Plan Mapping – 10/17/23**
- **Slide Deck – Gridworks IRP Stakeholder Meeting #10 – Final**

Meeting Purpose and Outcomes

The purpose of the meeting was to review the Statement of Need and Action Plan and to identify any areas of disagreement.

Modeling Update

The PNM team provided an update on several stakeholder requested runs:

- accelerated carbon free scenario
- extreme weather reliability sensitivity
- correlated gas outages reliability sensitivity
- battery degradation reliability sensitivity
- resiliency study focused on winter conditions and the benefits of having access to regional markets

Data for these analyses are included in the VENUE database.

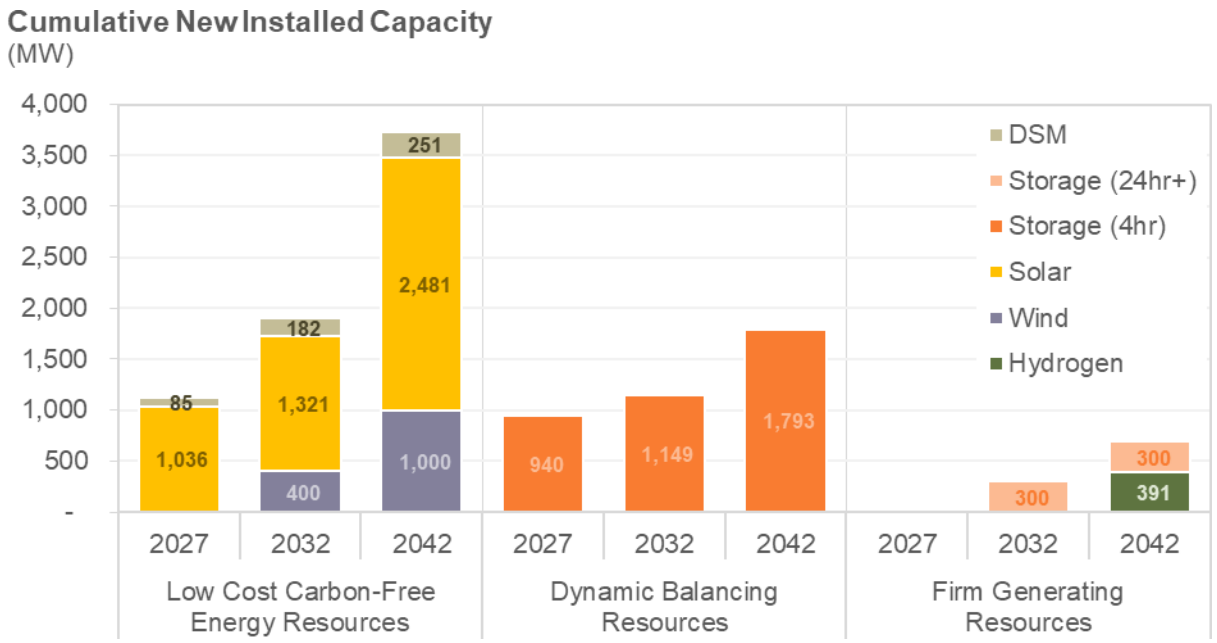
Statement of Need

The PNM team reviewed the current version of the Statement of Need and stakeholders offered the following comments:

- PRC Staff requested the L&R tables in advance of filing. The PNM team responded that such data are currently available via the VENUE database.
- WRA suggested that annual carbon emissions of each portfolio be included in the IRP. The PNM team invited stakeholders to review Appendix J of the 2020 IRP to see what is currently envisioned on this topic.

The PNM team described and addressed stakeholder questions about Figure 1 (below, from the draft SoN)

Figure 1. Summary of future resource needs in our Most Cost-Effective Portfolio



Stakeholders were invited to submit comments on the draft SoN to INFO@gridworks.org by NOON MDT on Friday, Oct. 20.

Action Plan Discussion

Stakeholders were invited to suggest changes to the draft Action Plan (**PNM Action Plan DRAFT 2023 IRP – 10/17/23**). WRA, SWEEP, and NMSU representatives did so. The group discussed current and future RFPs, exit from some existing generation assets, and the IRP defined action plan period (2024-2026), noting some uncertainties with the timing of these elements. Stakeholder requested action plan

ideas that were not adopted are explained in the ACTION PLAN MAPPING document (**PNM Action Plan Mapping – 10/17/23**).

Next Steps

Comments on the draft SoN and Action Plan are welcome via the facilitated stakeholder process by NOON MDT on Friday, Oct. 20. After this date, comments can be submitted to IRP@PNM.com with copy to INFO@GRIDWORKS.org. (Note that there is no guarantee of incorporation or responses after Oct. 20.)

Key Dates

- Oct. 20 by NOON MDT – Comments on SoN and Action Plan welcome to INFO@GRIDWORKS.ORG
- Mid-late November – Draft IRP available for stakeholder information
- Dec. 15 - IRP is filed by PNM
- Dec. 19, 9:00 - 10:30 AM WEBEX Meeting - Final stakeholder meeting to collect input regarding how stakeholders experienced the process. To register for this meeting please go to https://www.pnmforwardtogether.com/schedule-and-events. You will see the WEBEX meetings listed; please click on "REGISTER" to be added to the meeting.
- Jan. 31, 2024 - Gridworks' report is delivered to the NM PRC. The report will include the results of both NM IRP Facilitated Stakeholder Processes (PNM and SPS).

Public comment on the IRP is allowed during the 30 days following filing the IRP via the NM PRC system. Given the current schedule, this period ends Jan. 15.

Closing and Request for Feedback

Gridworks thanked all stakeholders for their engagement, insights, and suggestions in this new process. Gridworks appreciates those who completed the survey during the meeting. Others are encouraged to complete the survey by visiting this link: bit.ly/PNM-IRP-Feedback, or scanning the QR code shown here.





QUESTIONS AND ANSWERS

PNM Public Advisory Process (April 28, 2022 – March 15, 2023)

General

Kickoff Meeting: April 28,2022

Member of the Public: Virtual Meetings

Will all meetings be available virtually?

PNM Response

Yes.

Member of the Public: Diversity

What do you mean when you say that PNM is one of the top companies in the U.S. for diversity?

PNM Response

We mean diversity in terms of the diversity of employees, including minorities and women, especially in leadership.

Member of the Public: PNMR Role in IRP

Where is PNMR (PNM's holding company) in terms of public outreach with the IRP?

PNM Responses and Subsequent Questions from Member of the Public

PNM is a wholly owned subsidiary of PNM Resources. PNM is a regulated utility subject to the rules and procedures of the New Mexico Public Regulation Commission (NMPRC). The IRP rule applies only to PNM, not PNM Resources. PNM Resources is a publicly traded company not directly subject to the regulatory oversight of the NMPRC. PNM is responsible for developing the IRP and must make filings and gain approval from the NMPRC to acquire any resources subject to the NMPRC's Certificate of Convenience and Necessity ("CCN"), Power Purchase Agreement ("PPA"), and other applicable rules.

Member of the Public

What PNMR businesses are within or outside the IRP process? What percentage of PNMR are in each of these categories?

PNM Response

The only PNMR business subject to the NMPRC IRP rule is PNM.

Member of the Public

Does anything in the non-regulated sector impact on PNM's planning and/or operations? If so, how?

PNM Response

Many things in unregulated sectors impact PNM's planning and operations, such as the price for new resources, the cost of natural gas, the cost of capital, regional markets and other factors – all of which are not regulated by the NMPRC. Most of the fundamental drivers in the planning and operations process are things beyond PNM's and the NMPRC's direct control. PNM plans within uncertain environments to best meet its customer's needs. PNM's rates, procurements and operations are regulated by the NMPRC.

Member of the Public

How do unregulated activities relate to the IRP process?

PNM Response

See response to the previous question.

Member of the Public

What are the PRC's objectives and expectations for the IRP process?

PNM Response

The NMPRC IRP rule provides the objectives of the IRP process.

Member of the Public

In the revised IRP rule 17.7.3.1 NMAC of 10/27/2022, which parts are new, and which carry over from before? A table showing the changes could be helpful.

PNM Response

Please find attached Exhibit B which is a redline of the previous rule to the new rule which was filed in the IRP Rulemaking Docket, Case No. 21-00128-UT.

Member of the Public

Where are the stakeholders defined in the new Rule?

PNM Response

Stakeholder is not a defined term in 17.7.3 NMAC.

Member of the Public

How do the commission or PNM know when enough varied stakeholders are participating to meet requirements?

PNM Response

The facilitated stakeholder process that is currently being conducted by Gridworks has been sent to a very broad group. Facilitated stakeholder process is defined in 17.7.3.7(F)(1) NMAC.

Member of the Public

What happens if no stakeholders can be enlisted from a given key sector?

PNM Response

The Commission determined in its rulemaking that the Commission-defined facilitated stakeholder process is appropriate to receive public input to the IRP.

Member of the Public

How does the Statement of Need relate to PNM's business plan and operations?

PNM Response

The Statement of Need defines requirements that PNM must meet in the future; however, before finalizing agreements with any new resources, PNM must seek approval from the NMPRC through filings for a CCN, approval of a PPA or other applicable approvals. Therefore, the Statement of Need outlines a high-level roadmap for future procurements and investments by PNM, but actual outcomes may vary when specific market bids are sought to inform procurement analyses and filings.

Member of the Public

Is the Independent Monitor for RFPs a new element under 17.7.3?

PNM Response

Yes.

Member of the Public

Under 17.7.3.12**(**F)(4) NMAC, What is meant by "resources be able to operate under automatic dispatch control"?

PNM Response

Resources that have Automatic Generation Control (AGC) can follow a dispatch signal sent by the remote system operator to vary its output to a desired set point.

Presentation: May 25, 2022

E3 (Energy + Environmental Economics)

"Resource Adequacy in the Desert Southwest"

Member of the Public: Presentation Slides

Are the presentation slides available?

Initial Response: E3

Yes, they are available on the E3 website, as well as a full technical report and a recording of the public webinar E3 hosted at the outset of our public rollout.

PNM continued.

The slides are also available on the PNM website with a link to E3's website.

CSOL Power: Hydrogen gas turbines are not the answer.

Hydrogen gas turbines are not the solution for electricity generation, which needs to be done only by wind, water, sun, and some geothermal. We've waited so long for climate action, that we now need to actually move into World War II style deployment of wind and solar. And yet, we are not utilizing the wind that we have in eastern New Mexico. We need to make sure we're looking in the right direction and going as fast as we need to go because the generations after us deserve a sustainable planet.

Initial Response: PNM

This comment speaks for itself. That said, E3 has done a lot of work on regionally integrated resources plans looking at how other utilities incorporate transmission planning; they may be able to give a broader perspective on other resource plans E3 has worked on and how transmission is done in other regions.

We're trying to do the best we can. It's just a very, very complicated way to do generic transmission and generic resource planning. You really need to have the specifics of locations and resources within an RFP.

E3 continued.

We would underscore that incorporating transmission planning into a resource plan is a tall task, not to say we shouldn't try to take steps forward to do a better job with it. Definitely, it is a challenge for the reasons PNM has laid out.

PNM continued.

Information on the different mixes of existing resources and the different types of resources included in the study are based on what the individual utilities provided. These are the resources the individual utilities found were the best mix to meet their obligations to their customers at a reasonable cost while also meeting their environmental constraints. In addition to what is economical, they considered what's available within their jurisdictions and what their forecasts are.

E3 continued.

The mix ends up looking a little bit different for each utility, although almost every utility has a large portion of new solar and storage built into their future plan. Each also has opportunities to build in resources like wind, geothermal, and natural gas, and demand response. This covers the big picture.

Member of the Public: Excess Generation

Is there any excess generation available for use, like that sold in the market, for example? (Slide 31)

E3 Response

This slide is largely focused on the availability perspective.

This is a summer peak day, a day when the region as a whole is probably relying on the resources it needs at maximum capability in order to meet its needs.

There would be many other times throughout the rest of the year when loads are lower, when there would be an available surplus of energy or even energy that utilities want to be able to sell into the market to avoid, for example, renewable curtailment.

But that's just not the picture we see on the summer peak day.

Also, even as the region comes to rely more and more heavily on this combination of solar and storage to meet its summer peaking needs, you do still have remaining firm resource needs. Given this amount of solar, storage, wind, demand response, and hydro that is built into the utilities' portfolios, there is still a pretty significant need for firm resources, including any flavor of nuclear, coal, or natural gas that can be dispatched on demand and for sustained periods of time.

And we see that being true through 2033. A common finding that we've seen in all of our work, even as we push the envelope even further: Some form of firm capacity will be needed to maintain reliability, even as the grid approaches 100%, or really ambitious targets for renewable or carbon free resource integration.

CSolPower: Too Much Natural Gas, Not Enough Wind

Looking at the different utilities' plans for what is coming on online, there is still way too much natural gas and not enough wind. So, is this study based on what has been in previous plans, and not the reality of addressing climate change?

E3 Response

The study represents the utilities' current or previous resource plans, including the capacity of different resources. Here, you're looking the amount of installed capacity within the portfolios, which is a different picture from the amount of energy that these resources generate over the course of a year—something more directly linked to the sort of climate impact that any one of these portfolios might have.

Regarding an earlier question about the dispatch of energy storage and its treatment in the study, an important qualification for this entire exercise is that E3 modelled the southwest as a whole, requiring us in a study like this to make certain assumptions as to how effectively each of the utilities can share its pool of resources with others, especially as the grid enters into more tight conditions.

And so, what this analysis represents is essentially, in some respects, an optimistic perspective on how the total portfolio of resources within the region could support the total needs of the region. The reality of our world today, however, is that we're not perfectly in a fully optimized market, and it is the domain

of each utility to assess its own loads, resources, and exposure to the market under loss of load conditions.

So, looking at this on a utility-by-utility basis, you might end up with slightly different answers than we found in this study, but we believe our general findings are valid.

CSolPower: Outlook for 2033

Is the availability for 2033 64,000 megawatts? (Slide 18)

E3 Response

Yes. That's a figure that's definitely in our technical report.

On the previous question around transmission, because this is a regional study, we didn't include a very detailed representation of internal transmission constraints within the system. So that's another reason that you might think of this as a slightly optimistic view as to the ability of the region as a whole to collectively share its resources to meet the region's needs.

Here (Slide 27) is what the system looks like from the different perspectives of installed capacity, effective capacity, and annual generation.

These are three different ways to think about various aspects of a system.

On the far left of this graph, you see the total installed capacity of the different types of resources across the different scenarios. There is expansion by 2033, in our IRP scenarios, up to close to 60,000 megawatts of capacity. Again, most of that new capacity coming from renewables and energy storage.

In the middle panel, we take that installed capacity, and translate it into effective capacity, or ELCC capacity. This is essentially where we've tried to take those installed capacity numbers for every resource in the system and direct them, based on LLP modeling, to account for what those resources provide to the system, when it's truly constrained, when it truly needs it most. And here you can see that the corresponding bars for the renewables in the storage have actually shrunk quite a bit. What this reflects is the implicit limits on these resources and their contributions to resource adequacy due to variability and duration limits. And in a comparative sense, the remaining firm resources like coal and natural gas get a much smaller haircut on an ELCC basis.

But the picture on the far right is the one that's perhaps the most relevant for the questions around climate and clean energy. That is the question of an annual basis over the course of the entire year: How much of energy is being supplied by these various types of resources? And so, this is a transition that we see occurring.

Given this portfolio of resources. If you look today across the region, we're probably at 35% by 2026 carbon free energy. By the time this transition to this specific portfolio occurs by 2033, you'd have approximately 70% carbon free energy in the system that is coming largely from a mix of nuclear, solar, and wind resources.

Right now, PNM is a little bit ahead of that curve on the energy mix for our portfolio. We're about 50% carbon free right now and expect to be ahead of the curve for the overall region going forward,

Member of the Public: Water Shortage

We're a water shortage region. How has that come into planning?

Initial Response: E3

It affects the planning in a number of respects, some of which are not taken into account directly within our study, and some of which are, certainly, as water becomes more and more constrained within the region. And that may have impacts on economic growth within the region. That's something that you would expect to see show up within utilities' load forecasts--their expectations for future economic growth.

We've taken previous load forecast from utilities at face value, so we haven't made any assessment or judgment as to how water use within the region might impact those forecasts. But we think that is something that we would expect utilities within the region to be thinking about.

On the supply side, the risk of drought is something that we did try to think about and factor directly into this work. Essentially, within a model like this loss of load probability model, we have some representation of how much energy is available from the region's hydro resources. And the amount of energy that's available, you can imagine, is a function of what the underlying hydro conditions are.

What we tried to do, and this is based on input that we've gotten directly from the Western Area Power Administration and the Bureau of Reclamation, is characterize the relative risk of severity of drought in a probabilistic way, such that there's some probability in our model that you end up in a really critical hydro situation that reduces the value of the region's hydro resources. In some cases, you may be in a more normal condition on a relative basis, and you have a little bit more capability. So, on the supply side, that's how we would expect that to come into play.

PNM continued.

From PNM's perspective, looking at the resource plans that were in our 2020 IRP and the types of resources we're looking at now—and this is pretty true broadly across the West—the new resources that are coming on board are much lower water use resources than the resources that are being retired. So, when you think about coal plants have steam boilers being retired and replaced with solar storage, maybe aeroderivative, and natural gas turbines that run very infrequently and that don't require much water, the net water usage for electrical power generation is significantly decreasing, say, for any entity building a pumped hydro plant or something like that.

TECHNICAL SESSION #4: July 27, 2022

NM RETA: Generation Sources That Met Record Peak

Once the record peak is final, will PNM be breaking down the generation source contributions that were used to meet the peak: For example, what came from San Juan? What came from natural gas generation? What came from solar? What came from wind?

Initial Response: PNM

We can certainly take that [question] back. It's not something that we have done in the past. We can certainly take that back and see if it's something that we can go ahead and include in a presentation going forward. That does remind me there was a previous question about presenting historic peak information. We do have a filing we make every year--it's our Case 3137 filing. It shows a load and resource balance, including a forecast for peak each year. So, we will post a summary of that.

We would note that there are differences in the way resources are accounted for as well as the contributions of different resources over time, as folks have probably gathered from previous presentations on ELCC [Effective Load Carrying Capability] that resources will change as a function of both system conditions and the penetration level of given resources on the system, as well. In the last IRP we move from installed capacity accounting for thermal resources to force capacity accounting. So, you'll see some differences in the way the numbers are represented. Take that into account.

You can also go to the [Public Regulation] Commission's website to search for the Case 3137 and pull out those filings we make each year to take a look at what the loads and resources tables are showing.

PNM Update

2022 Summer Peak Resource Contribution

Resource Type	Percentage of Generation
Natural Gas	27%
Renewables	22%
Wind	9%
Solar	13%
Geothermal	<1%
Coal	20%
Nuclear	18%
Imports	13%

TECHNICAL SESSION #11: December 15, 2022

Member of the Public: Tax Changes with Loss of Fossil Fuels

As cost allocation will change, is some change in tax structure expected to make up for the government revenues that will be lost as we use less fossil fuels?

PNM Response

Setting aside things like gas taxes for vehicles and things like that, if you're talking about all electric fleet, that's a bit aside from what we would do here at PNM. The PNM customers at least pay a gross receipts tax on their electric bills, so that would be applicable to our total revenue requirements.

As long as we're recovering our overall revenues, if any individual customer reduces or changes their usage patterns to optimize their costs, that would change the gross receipts taxes to the State of New Mexico a little bit. That's something that needs to be kept in mind as to how the legislature is going to look at what their revenue needs are going to be relative to the overall gross revenues collected by all the different businesses throughout the State.

Grid Modernization

Kickoff Meeting: April 28, 2022

Member of the Public: Powerwalls

As we expand residential commercial batteries through powerwalls or charging automobiles, we need to be assured that those facilities have capabilities that maximize the utilities [available to the public], not the company. For instance, we could have greater reliability through some system that allowed PNM to utilize the capacity when it's not really needed by the resident, but there has to be some kind of relationship with manufacturers or some requirements that, if you have a powerwall, it has to have at least these kinds of capabilities. Is anything like that happening, and how do we make sure it's not an advertising gimmick for [electric] automobile manufacturers?

PNM Response

There's a lot happening in this area: How are we thinking about how the system will interact with customer owned storage or other devices? Or are there other ways that the utility can partner with customers to ensure that they are as involved as possible with the transition towards carbon free?

So, you might have seen some commercials out there—of a truck that can plug into the house and can light the house in the event there's a distribution outage. So, there are two-way chargers that are going to be available to allow an electric vehicle to charge or discharge back.

You can also have behind the meter storage. Some of the questions to consider:

If a customer is paying for behind the meter storage, they may want to use that to optimize the benefits from that against their utility bill, and that may not be the best thing for the system.

Or does PNM then open up programs—something we are looking at—where we could either incentivize a customer to sell us the ability to utilize, say, 50% of their battery for the benefit of the system.

Or could there be utility programs where the utility does something, to start doing more distributed energy resources that may or may not be utility owned, but we can then manage and figure out the proper incentive mechanisms to ensure that we can operate those for the benefit of the system -- and not necessarily focusing on tariff optimization.

We have a completely above the board approach as we are going into this transition. We are considering AMI [Advanced Metering Infrastructure] and grid modernization (grid mod) as well as distributed energy management resource systems. as well as distributed energy management resource systems.

Member of the Public: Powerwalls

I appreciate that [one car company] is doing that. How do we make it a requirement so it's not an advertising gimmick but something real that can benefit the country?

PNM Response

PNM has had discussions with big name automobile manufacturers about pilot programs in terms of dedicating a fleet of vehicles to using two-way chargers to look like a large battery from the utility's point of view. If we go back three or four years, the biggest hesitancy from the automobile manufacturers was on the warranties of the batteries; they're starting to get over those trepidations.

Member of the Public: Effect of Proposed Changes on Sub-populations

What sub-populations of the PNM customer base are going to be impacted and in what order? How do we keep that in balance, both for the system and as we have more distributed generation? How does that change the role of the grid and other factors?

PNM Response

If we're thinking about this from the reliability perspective, there are probably things that we can do with distributed resources. That would mean considering microgrids or things we could do to prop up specific areas of the distribution system to be a bit more resilient and reliable. There are things going on right now like that--maybe at the edge of a feeder or something similar.

We will do our best to cover this issue in this IRP process.

Regarding the IRP, we're looking at things from a bulk transmission level. So, we're not seeing any individual distribution feeders. We have to understand what the aggregate effect of all of the distribution and distributed energy resources are and incorporate those.

Member of the Public: Bidirectional System

If it turns out that sometime down the road that it becomes obvious that the system needs to be more bi-directional, will you be looking into the costs associated with that?

PNM Response

If you mean allowing enough feeder capacity and reverse flow to come from the distribution behind the meter side back onto the PNM system, that's certainly a problem we're facing right now. There are some feeders that are getting to the point where they can't support any additional behind the meter solar.

There are ways we can deal with these issues, and PNM's distribution planning department is working on the ability to add storage or other things to try to alleviate some of those constraints. All options [are] on the table, and the grid modernization and distribution planning groups are working on say, if they're exporting that much power, how do we then examine that from the bulk transmission level?

From an IRP perspective, we will be discussing the issue more, including at the upcoming Grid Modernization meeting.

Sandia National Laboratories: Retail Rate Design

The IRP process could benefit from a technical session discussing retail rate design. What kind of rate designs would be enabled by AMI?

PNM Response

We are allowed to talk about rate design in the IRP process, and we did in the 2020 IRP, with a load forecast scenario that looked at very aggressive time of use pricing rates and showed what the anticipated impact to our load forecast would be based off of that time of use rate shift that would make requiring AMI to implement that type of behavior likely.

Going a step further, 'How are we going to look at the rate designs for electric vehicles?' Considering perhaps a super off-peak rate during high solar production to influence when electric vehicles will be charged is certainly something that we should be considering.

One of PNM's requirements, going forward, starting next year, is to show that we are serving our customers with an averaged carbon intensity of 400 pounds per megawatt hour or less over the course of the year; that goes from 2023 through 2031, and then drops to 200 pounds or less in 2032.

And so, one of the key things that we learned in this last planning cycle is when you get to 2032, when you have that step down from 400 pounds to 200 pounds, it's really about decarbonizing the off-peak hours. And if you're not incentivizing electric vehicles to be charging when the sun is shining, you've got additional solar. It creates a much larger problem to try to decarbonize the off peak if you're adding load in the long peak.

Rate design topics presented on December 15..

Member of the Public: Effect of Individual Storage Systems

As you put more and more individual storage units into a gateway system that gets smarter and smarter, could you use artificial intelligence to program a group of gateways to manage the system on a real-time basis and not worry about we'll take from person A, B, or C? Artificial intelligence will do it fast.

PNM Response

We will need to see some greater advancements in the control systems for energy storage: the ability to make sense of all the simultaneous decisions that could be made. There are over a dozen different use cases for energy storage in terms of different values that they can provide. And trying to figure out which is the right one, in the moment, is something we doubt humans can do. We're going to have to make sure that we've got algorithms that can do it and in a very intelligent way.

Member of the Public: Extreme Weather Events

Can the system be more robust in an extreme weather event?

PNM Response

The specific concern raised about the 2020 IRP was that some thought that the load forecast by the time we got out to 2040 was wrong. We had a lot of different load forecast scenarios. Granted, the further out in time you go, the more uncertain forecasts are. We think we're using industry best standard practices for load forecasting, but we can have a conversation about it.

We are scheduling a technical session with PNM's load forecasting group to discuss all the parameters, and, if there's a different load forecast scenario that needs to be considered, we can have them generate one and run it through the portfolio model.

Another topic that was raised in 2020 was renewable resource cost development. Perhaps folks didn't understand exactly how we develop renewable resource cost assumptions. We can go through in detail what we did and if there are alternative methods. Something else might be more appropriate, so let's figure that out.

And the same thing would go for the other candidate: resource technologies. We recently issued two requests for information (RFIs). We did one very similar to what we did at the outset of the last planning cycle, where we were asking for new and emerging technologies to look at things that would help us to decarbonize the system. There are no limits on whether it has to be a utility or supply side resource or demand, right demand side resource, or distributed energy resource. We're hoping to see the whole kit and caboodle in terms of the amount of information that we receive.

We also recognize that there are some technologies that take a long time to develop. In the last planning cycle, there were two or three long duration storage projects that typically take five to 10 years or longer to be developed. And so, we put out a second RFI to try to get more specific information about not just general technologies, but also specific projects that may have long lead times. The RFIs are due June 15 and respondents' updates by September 15.

The deadlines for the RFIs correspond to when we want to bring the responses back to our stakeholders to discuss these different technologies and resources, and how we can incorporate them into our modeling protocols, making sure that we have the ability to run them as resources for load serving requirements in our model when we start doing the full scenario analyses in the September-October timeframe.

The long duration storage RFI and also hydrogen resource modeling were some issues that raised in the 2020 IRP comments, so we'll want to discuss those. We've been doing some additional testing and modeling -- R&D -- within our own groups. We can talk about that as well as general ways these things are modeled if there are other assumptions about them. For example, one question was about how much water does it take to make hydrogen and does PNM have access to that kind of water.

Distributed resource modeling is on our list for discussion as well. We want to make sure we talk about that as much as we can but, again, that one gets a little bit tricky because the IRP is at the bulk system

level, not at the individual feeder level. But we do have to make sure we can figure out how we account for all of those DRs when we are designing a least cost plan.

Regarding scenario tree development, I was explicitly thinking about the Four Corners Power Plant Thinking about the different scenarios and sensitivities that we're going to need to run, how are we going to model the existing resources? What were we doing with our existing resources? Is that the best use of them or the most appropriate way to consider the existing system?

Presentation: May 25, 2022

E3 (Energy + Environmental Economics)

"Resource Adequacy in the Desert Southwest"

CSolPower: Electrification of Vehicles

The IRP process should discuss the electrification of vehicles and how [residential battery storage might work beyond individual household use.]

PNM Response

We will absolutely incorporate this idea into PNM's grid mod plans--more customer participation, communications equipment, or real time, smart meters and smart chargers, for example—so that residents don't just return home from work or errands, plug in their cars, and start charging at the wrong time of the day.

Most people have smartphones now that charge slowly overnight but charge really quickly at other times. We can use these same types of functions for electric vehicles, where perhaps a commercial entity with a fleet of electric vehicles would have a charging infrastructure and use it as a battery, as needed, for the entire grid. We must figure out how to price that type of program and decide the kinds of incentives to put in place.

If you're trying to figure out how to decarbonize the entire economy, it might start with the electric sector. Once you get the electric sector emissions down pretty low, you've still got a lot of emissions coming from transportation and natural gas for heating homes, for example. And once you get emissions out of the electric sector, you've got to replace those other forms with electric cars and other such things.

We will discuss this issue at the upcoming Grid Modernization meeting.

Also, we will cover load assumptions regarding electric vehicle adoptions in the Load Forecast presentation..

Member of the Public: Moving Off the Grid

How do we anticipate moving to off grid? Are people putting their own batteries onto their own solar systems and how will they interact with the grid? How does that in the long term, or even the near term, impact what we're doing here?

Initial Response: E3

We definitely are seeing a trend within the industry towards customers who choose to put solar on their rooftops are also beginning to choose, in some cases, to pair or co-locate battery storage behind the meter. To some extent, when it comes to resource adequacy or reliability, that behind the meter storage might be seen as somewhat of a substitute for the grid scale storage, in the sense that its technical capabilities are aligned or more similar to what a grid scale battery would give you.

That may be technically true, but it may also be optimistic in the sense that it would rely on that customer to use their battery in such a way that's completely aligned with the utility's needs. And what we'll often see is that customers do choose to use their batteries in ways that are more consistent with the price signals they receive through their tariff or their rates.

So, in that sense, as the portion of storage that's behind the meter continues to grow, there's maybe a need, if we want to get as much value out of those storage resources as possible for society as a whole, to ensure that tariffs and rates are well aligned with utilities' needs and encourage the right types of behavior when it comes to how those resources are operated behind the meter.

PNM continued.

The way that we would need to look at the distributed resource additions is that they can take the place of some utility scale resources, so long as the utility is able to manage those resources through a distributed energy management system, or otherwise send out completely aligned price signals with the current state of the system. If you've got real time pricing, or advanced metering infrastructure, customers know exactly what's going on with a system's prices, as opposed to legacy block rates that don't necessarily align price at a specific moment in time with the way the system is being operated.

If you can align the way that the distributive energy resources would work in conjunction with the rest of the system, they can take the place of some of those utility scale resources that are part of our grid mod discussions.

You could see it in the form of micro grids, or in a number of different ways. But getting customers to participate and act in a way that's beneficial for the system, not just beneficial for themselves, is the key to ensuring that the distributed resources are really taking the place of some of the utility investment.

Perhaps it will be utility incentives, or utility programs that customers can take part in in order to participate that way. But there are a lot of mechanisms we could consider but we will have to align the customer incentive and customer behavior with the utility system's perspective to ensure whatever mechanism works.

Technical Session #1: June 8, 2022

Member of the Public: Electrification Beyond Cars by 2040

Will PNM consider scenarios for electrification of the economy beyond cars by 2040?

PNM Response

Yes. Different load forecast scenarios will be part of the July 6 presentation.

In the 2020 IRP, along with looking at increased penetration of electric vehicles, we also did some load forecast work on increased adoption of building electrification. In this IRP, we've also been doing some work in terms of modeling. We did hydrogen last year, and we did it in a simplified way, where we assumed a hydrogen economy.

An alternative is modeling electrolyzers [hydrogen generators] themselves, the loads that they would add, and, of course, producing hydrogen. You are going to have electric loads associated, though, so we are modeling those more explicitly.

We also want to do even more rapid transition towards building electrification, if we assume that everything has to be electrified by 2043, or 2042, which is going to be year 20 of this IRP.

We will be doing transportation electrification, at least three different scenarios or sensitivities, in terms of the load forecast, and how it would be affected by electric vehicle charging. We will also have the building electrification scenario or sensitivity. And if there are other things stakeholders want to consider, then, absolutely, we can figure out how to work them into the IRP.

Member of the Public: Distributed Generation

As we get distributed generation coming on in small pocket areas or micro grids, what happens when you have little pockets spread throughout the system? How do we get that to feed back into the system? How do we begin to understand that? What are some of the factors we should be looking for or where we should be looking for data when we may not have much of it in the PNM service area?

Initial Response: PNM

We will explore this topic under grid modernization, and PNM's distribution planning team will also present some of their ideas on distributed resource management at an upcoming meeting.

Some of this planning will also come down to how the interconnection processes. What makes the most sense? For example, if something is behind the meter, or you have a smart inverter that is never going to be exporting back onto the grid and is just covering the load that's behind the meter there, you don't have to go through a FERC work desk interconnection process, as you would if you were actually exporting back onto the grid.

So, depending on the penetration levels of those distributed resources, as well as how you might be able to integrate everything back up into a centralized, distributed energy management resource system, you

may not actually want a lot of counterflow back into the system. So that's another piece we encounter now; it's probably because of net metering rates.

So, the systems are oversized to dump power back onto the grid. But in the future, you might want to look at more as well: The resources behind the meter should be really just serving the load behind the meter.

These are important things to keep an eye on. How can we begin to formulate AMI ideas about how best to work together?

The distributed energy piece is going to be a big one, and we see distributed resources growing. There is no denying that. It makes sense to ensure that distributed resources are done in a way that maximizes the value to the system and that the system stays resilient and provides the value to the folks who are spending the money on it.

We are discussing this internally in PNM and are trying to figure out the best way forward. Some of this planning will be in a PNM grid modernization filing later this year.

Technical Session #3: July 6, 2022

WRA: Distributed Storage

Please say a little bit more about distributed storage. Did you mean on the utility side of the meter? Or did you mean customer-owned and controlled storage?

PNM Response

This is something that we'll dive into much more detail in a future meeting--probably along the lines of grid modernization (grid mod) and distributed resources. It's both. As we move the system forward, if we want to get to the fully decarbonized system, unleash the power of our customers, and make sure we're doing everything we can to move this forward, there's going to have to be incentives for behind the meter, customer-owned storage.

Having those incentives right and having those hooked into a distributed energy resource management system, so that the utility operators are actually the ones who can control that storage to some degree is important because the more we align the operation of behind the meter resources with the system requirements--and not individual customer requirements--the more those resources can offset the larger utility scale transmission side and resources.

We're also going to need to have utility-owned distributed source storage on our side of the meter at different places, depending on the location and the customers. There may be advantages to the utility owning and having it on its side of the meter versus on the customer side. It may be both. There is also going to have to be utility scale storage; you're going to have to have it in the load pocket; and you're going to have to have it out near resources.

We envision this as using storage as the way to manage the dispatch of the system to manage reliability and to manage the efficient use of the transmission and distribution system. There's going to be so much storage on there and so many different components of it, that it's all going to have to be worked into computer algorithms--using AI and other things to make sure that we're able to manage this all--in real time.

We don't think you want to count out any of those options. We need them all in order to make sure that we can manage the system reliably and cost effectively and move the decarbonization path forward. We can't eliminate any of our options right now.

NMPRC: Feeder Capacity for Solar

Does the solar implementation assume that there is adequate feeder capacity, smart meters, etc. to allow the proposed residential solar projects to be built?

PNM Response

Yes, if everything could be interconnected, efficiently, and if we can alleviate the constraints. Our PNM subject matter experts who developed the forecast will do a presentation on it.

If there are things that need to be done to the interconnection process that can be overcome, we will need smart meters--as more and more of distributed resources are added, we will have to have a view into the edge of the system right up into the customer points. With smart meters with AMI (Automated Metering Interface) we will be able to manage renewable production and customer usage by each individual meter.

In order to make sure that our operators are able to manage the system effectively, they can't be blind to what's going on behind the customer meter. They have to be able to see that, especially, if this adoption rate is what we see materialize, it would represent approximately 1250 megawatts.

Right now, we're a 2000-megawatt system, and if we have approximately half of the resources of the system behind the meter our operators will have to have visibility in real time to make sure they can operate the system.

Technical Session #7: October 17, 2022

Member of the Public: GHG

What is GHG?

PNM Response

That's greenhouse gas.

So, we're talking about how we are trying to empower customers to take more control over what their greenhouse gas footprint would be. And that could be from putting more rooftop solar or storage directly on their side of the meter, or it could be enabling additional reductions in their greenhouse gas footprint by allowing for more electric vehicle infrastructure and a number of other things-- just controlling their overall energy consumption in a way that's more beneficial for the system through getting additional real time information from the advanced metering infrastructure and other such things.

InterWest Energy Alliance: AMI Value

A recent study shows that 97% of AMI (Advanced Metering Infrastructure) value is failing to meet its promises and there's a cite to a Utility Dive article. Is PNM proposing anything here that is different than 78% of utility customers that already have AMI meters?

Initial Response: PNM

We will get back to you on that. We're not sure exactly how these other 78% of utility customers are doing AMI or things of that nature. We will say that AMI is going to give us more information and it’s the way we utilize that information that's going to be important.

For example, time of use rates or time of day rates are a tool in the toolkit. It's not a silver bullet that's going to magically cause customers to change their behavior and completely overhaul the entire system in a more efficient way. We know that, typically, electric usage is relatively inelastic. So, a lot of the efforts also must be done through education and other such things.

PNM Public policy/legal continued.

We're not early adopters. Obviously, nowadays, there are a lot of other states that have already done this, and we have the advantage of learning from some of what they've done. Our consultants have had years of experience, as well as experience working with DOE to develop some of their standards and their planning.

We at least have some ability to reflect on what has not been done well, and make sure that we're incorporating best practices, which we think we've done in our robust plan.

PNM continued.

We'll have a look at all of the things that are typed in the chat window [during this session] and will take a look at that article. We don't think we can compare and contrast PNM's plan going forward to what other utilities that have already put AMI out there have done or failed to do**.**

InterWest Energy Alliance: Regional Energy Needs

The grid mod statute includes a requirement to consider whether grid mod applications are, "designed to support connection of New Mexico electrical grid into regional energy markets and increased New Mexico capability to supply regional energy needs through export of clean and renewable electricity," [according to] MNSA 62-8-13B2. How will PNMs plan comply with this requirement?

Initial Response: PNM Public policy/legal

Our grid modernization application focuses on the distribution side, but we do recognize that that is one of the aspects that the Commission can consider. That's in the statute.

Our testimony in particular does address that piece of it: It discusses what our current efforts are with regard to regional transmission discussions. When we were discussing the merger, which is not part of this discussion, but we as a company did make a commitment to have discussions with our regional partners to try to join or have discussions about some kind of a regional transmission organization.

So that's still something that we have been keeping informed about. We have participated in some regional meetings in Colorado related to regional efforts.

So even though this particular project or plan doesn't include transmission upgrades--it is focused on distribution--the RTO (Regional Transmission Organization) discussion is still part of what our overall efforts are as a company. We have also addressed it in our testimony in the application.

PNM continued.

We are currently actively involved in a number of different efforts exploring various regional transmission, organization, market design, things of that nature. In particular, PNM is participating in what's known as WMEG (Western Market Exploratory Group). Nick Philips, head of IRP, is chairing the subcommittee on resource adequacy and generation investment. There are other committees on market design and things of that nature.

Most of those efforts are looking at how you would implement a regional transmission organization or a more centralized market structure in the West but with a focus on sometime in the 2030 decade. These things are not going to happen overnight. They're going to take time.

PNM is one of the smaller utilities out there. In fact, we're either the smallest big utility or the biggest small utility. And these types of organizational shifts in the West are going to have to be led by some of the larger organizations. PNM can't make it happen by itself.

There are a few different things to think about. One, there's the Western resource adequacy program or WRAP that's looking at trying to do some more concentrated efforts around resource adequacy planning among Western members. The effects of that could flow into a couple of different market-based designs. One is the enhanced day ahead market or EDM, done through the California ISO. That will be available to EDM participants to do day ahead market scheduling for energy - that's not capacity. There's also an SPP (Southwestern Power Pool) West being designed.

And again, all of these are pretty well in their infancy stages and they're going to take time to develop. And it's going to have to be a look at where each and every one of these potential entities in the West would want to go.

There are over 30 different members exploring the potential market structures through WMEG. But again, the timeline really is focused on what could be done to deliver a market potentially sometime in the 2030 decade.

Member of the Public: Size of the Grid

Will the current grid need to be enlarged--or will distributed energy resources be reduced--or at least keep it at its current size?

Initial Response: PNM

So, the overall size of the system that we would need in order to serve our customers reliably, just thinking about the amount of, let's call it, nameplate capacity that we'll have on our system to meet our renewable energy requirements, decarbonize the system, and keep the system operational from a reliability point of view, we're going to need to see somewhere in the neighborhood of maybe four to six times the amount of nameplate capacity of resources relative to our peak load.

Right now, we're a 2,000-ish megawatt system. We actually hit a new all-time retail peak back on July 19 of this year: 2,071 megawatts. We have just a little over 4,000 megawatts of total resources right now to serve our system reliably. That includes a reserve margin, of course. But as we go further down the decarbonization path, with renewable resources, you can't always expect 100% of their output, especially not when you need it.

A solar facility, as an example, might give you across the course of the year 32% of its nameplate rating in terms of annual energy production, or what's known as capacity factor-- wind resources are maybe a little bit higher than that, depending on where they're sited. But compare that to, say, historically a nuclear plant or a coal plant or something that you can just turn on and run at full output, virtually for all hours of the year, you're going to get a lot less energy out of some of these renewable resources. You're going to have to have a lot more of them in order to meet the renewable energy requirements. Then we're going to have to have a lot more other resources in order to balance the system in terms of storage or other flexible generation to make sure that we can dispatch the system in a reliable way.

Going forward, we're going to need to have something in the neighborhood of four to six times the amount of total nameplate megawatts on the system to meet our capacity and energy requirements.

Now, it's not to say it is all going to be utility scale or utility sited. The more that's done on the distributed level--reduce requirements or utility scale operations, so long as they're able to be dispatched by the utility or they can be integrated in the system in an efficient way.

And that gets down to what we discussed earlier in the presentation on the distributed energy resource management system.

We're also going to think about increasing the amount of transmission that's available potentially, in order to deliver those resources or siting storage in a way to make use of the existing transmission system more efficient and start thinking about potentially energy only deliveries. We do have enough transmission capacity to deliver resources to load under N-1contingency conditions right now and serve our system reliably. But that means you may have to think about the way you deliver resources a little bit differently. We don't need to deliver every single megawatt of renewables as they're produced if we can store them and deliver them at different points in time when we need them.

Now, that's just talking about kind of planning 101.

When we start getting more into the resiliency aspect of things, as we have talked a little bit at a previous presentation about a supply side resiliency study that PNM does, one of the big takeaways there was if we want to take for example, the 200 megawatts of Four Corners out of the portfolio, and we wanted to replace that with an all renewable storage portfolio, we could do that under traditional reliability planning, by using a combination of 100 megawatts of four-hour storage, 50 megawatts of two-hour storage, and about 100 megawatts of solar resources.

But when we looked at that under some extreme weather scenarios and looked at how the system would perform under outage analysis, if outages were to occur, what we saw was that short duration storage plus renewable portfolio performed much different than a firm dispatchable type portfolio.

And if we want to align the characteristics, not just on a frequency of outage bases, but also on a magnitude of outage basis, the durations of those storage devices would have to be increased from two- and four-hour to 14- and 16-hour storage. So, significant increases on the overall dispatch.

And you can think about that in terms of the overall megawatt hours of storage that we would need on the system to make sure that we're able to respond to outages in a certain way.

So, it's not to say that you have to just add duration, you can also add power electronics and increase the capacity, both the charging and discharging rate, so long as you're adding that amount of volume of stored energy. But we're going to have to add more and more resources to make sure that we can provide the same characteristics of our traditional system and just take the carbon out of it.

To get back my initial point, four to six times the amount of nameplate is probably the minimum. You might see it has to be more than that. And it's going to have to be done in concert with distributed energy resources, taking those into account, looking at how we deliver resources, both the distribution and the transmission level, and how we're going to intelligently site storage to maximize the efficiency of the system, both of the transmission and the distribution level integrated from customers through distributed energy resource management systems. And looking at the supply resiliency side of it as well.

PNM Distribution continued.

What we like to think about in our distribution team is the deployment of these technologies that's in grid mod, and really where we're going with the integration of more renewables into the system, it's all about data, and then it's managing energy flow in two directions.

And so, if we have the data, we're able to optimize the design. And when we can optimize the design, then that is really taking the resource to its optimum level, and then at that point, we will have to add additional, maybe it's transmission, maybe its distribution substation, just depends on how the growth is occurring. And really, what's driving a lot of the transformation is growth.

And the other piece of this--the name of the game--is location is critical. So, where those energy resources are located, where the customer is located for the new load - that drives the resources or the additions to the system that may be required or not required, depending on what we can, if we can site energy storage or site resources near load.

PNM continued.

And then how efficiently that load utilizes the system is important as well. So, we think about the additional transportation electrification load or additional building electrification load, all those things that go towards decarbonizing the full economy.

We want to incentivize those loads to appear on the system at times where they're not going to add to the stress of the system.

So, if we can have charging loads, for example, occur during the middle of the day when solar output is at maximum, and we might be either in a position where we're having to curtail, sell off system, or store that energy, and it can be utilized by electrification loads, that's not necessarily going to add additional resources to the system. It's using the existing resources more efficiently.

But if people are coming home and charging their electric vehicles at times where we're already trying to manage a net peak load that could require us to add additional resources in order to make sure we can serve that load reliably.

So, there's, how efficiently the loads are utilizing the system, how are we incentivizing customers to participate in the right ways? We want to make sure that we're allowing all of this to happen. This brings to mind the adage that the utility industry is 5% of GDP but it's the first 5%.

In order to do all those things going forward that we want to do to decarbonize the entire economy--transportation, electrification, more building electrification--taking carbon everywhere else out, we have to have a strong and reliable utility in order to deliver the carbon free energy that we're going to be producing going forward to our customers and allowing them to utilize that throughout the rest of the economy to further decarbonize other sectors.

Member of the Public: Storm Outages and the Grid

How will the proposed system ensure operations in situations when the grid or advanced system goes down, as in a storm situation?

Initial Response: PNM Distribution

Let's remember that today, if we have an outage, the way that our operations center knows of the outage is when customers call in; we don't have visibility to an individual customer. So maybe the first

advancement with AMI (Advance Metering Interface) is that we will have real time energy information and we'll know if we have outages at a customer level.

So then, if we look at the blue chevrons right in the middle of the screen (Slide 11), there's a long bar there that runs from year two to year six; it's a distribution automation. So, we have the automation, sectionalizing, and bulk control. And then right below that we have the ADMS Fault Location Isolation & Service Restoration, the FLISR.

Those two systems will actually work in concert.

What you'll see in our plan is now, on a distribution level, if there's a fault that occurs, we're going to sectionalize our feeder into smaller subsections so there are fewer customers that are out. That's the sectionalization.

And then the FLISR piece of it is, if the fault occurs, we sectionalize and isolate the fault, and we can restore from another feeder, from another source. That's the FLISR.

So, the outage rates will be much smaller; the fault, wherever it may occur, will be isolated and sectionalized. Our crews and our operations center will know exactly where that fault is so they're able to dispatch the crews to address it in a much shorter timeline. And they're able to go right to the fault rather than having to patrol the entire feeder looking for the fault or the event.

And then all the other customers will be restored until we fix and resolve the smaller section that's out. Then, once that's resolved, we're able to return those customers back to service.

Member of the Public continued.

I guess where my concern comes, is when there's an outage--we have so many--we become so dependent upon these communication systems operating. If the communication systems fail, then many things in the past that have been available on a manual basis then become unavailable to most any level.

So, I need to think about that a little more, but maybe all of you need to think about it, too.

PNM continued.

That's a really good point. So, as our systems become much more intelligent, we're much more dependent upon data. We always design backups into our system as well. So, we have backup control centers. We have backups if we lose communication. So, there should always be a backup and a contingency.

But very good point. Thank you for that.

Southwest Energy Efficiency Project: Dynamic Pricing and Load Management

Is PNM proposing to roll out dynamic pricing and load management programs as the AMI (Advanced Metering Interface) meters are deployed to start collecting information?

Initial Response: PNM

We certainly are going to start collecting information. Our pricing team has already been meeting with a number of stakeholders in advance of our upcoming rate application filing later this year.

Speaking of a time-of-day pilot program--not to be confused with time of use rates--it is a more succinct rate structure that will try to better align the costs incurred by the utility with the rates that people pay during different points throughout the day. And it is also differentiated by season. We'll be able to talk about that a bit more specifically at a future meeting, but we are going to be rolling out a pilot program for that. This upcoming rate filing and continuing to try to advance that throughout the rest of the rate structure is going forward as more and more AMI gets deployed throughout the system.

But AMI, of course, can't be deployed overnight.

On the load management programs, we currently do offer demand response programs through our energy efficiency plan. That's the peak saver program and the power saver program. And we'll be talking about those and potential other options that may be available in the future at a future meeting.

There are a number of pluses and minuses associated with the programs that are done through energy efficiency. In particular, we want to try to make them available to as many customers as possible and minimize the number of customers opting out of the programs after they've joined.

These are 100% voluntary programs. That tries to keep more customers engaged but, on the other hand, it also makes it so that customers can opt out. And we can't always count on all that capacity for reliability purposes. But we do try to make sure that we make those burdens as flexible as possible to keep more customers engaged.

The power saver program is for residential customers, it's typically for HVAC loads, and it's dispatched cycling through HVAC loads across the system so that not everybody has all their air conditioning turned off simultaneously for an extended period of time, but typically rotating through turning air conditioners off--maybe 30 minutes at a time--for a subset of the overall program population and cycling through those a for a four-hour window. Now those programs are currently set to be operable June through September from 8 a.m. to 8 p.m.

The same applies for the peak saver program, which is a large commercial and industrial program that allows those types of customers to participate. Again, it's a voluntary program.

Combined, we count on about 30 megawatts of peak reduction for those programs towards meeting our reliability requirements. We do have more than that enrolled in the program. Because of the voluntary nature and looking at actual program operations compared to just what the nominal contractual obligations were, there's a bit of a difference there. So, we only count about 30 megawatts towards our reliability requirements.

As far as whether there will be new programs being offered going forward, once AMI is installed, we're always mindful that we want to make new customer programs for as many different portions of the population as we can. As we look at that we know our energy efficiency team--there's an active RFP out right now-- is trying to look at different types of demand response programs, something that might be it would be a bit firmer.

We always take a look at what other alternatives are out there. But we do have to be careful that we're not going to harvest or cannibalize, say, from one program to feed another. We want to make sure that we're not double counting megawatts or double counting things and are trying to make sure that we're serving our customers reliably.

So, you'll need to take a look at what makes sense for these programs going forward--as we've looked at some of the time-of-day pricing rates--and try to align costs in those with where the costs are incurred in our system, looking at where the loss of load probability is on our system, and trying to think about where we want to focus: potentially alterations to the existing demand response program to potentially make new programs to fill in gaps.

The risks and our shift in our system are moving later in the day--in the summer towards the net peak periods, that 5 p.m. to 10 p.m. timeframe, especially in the summer. And in the winter, we see kind of a dual peaking, where we'll start to see a little bit of risk in the morning hours as well as in the net peak hours in the afternoon.

So, as we get more and more information from AMI programs, as we start to see better into what our customers are doing, we will try to offer additional programs. But right now, we do have the two programs we are offering through the energy efficiency programs as well as an active RFP looking at potential new programs or increasing loads on the existing programs, depending on what those prices kind of look like and where we think we could get customers to enroll.

PNM Public policy/legal continued.

On Slide 11, you can see that second chevron under the green one that's basically under Customer Empowerment, which is advanced metering infrastructure. That's really the meters portion that we're talking about. It's going to be about a three-to-three-and-a-half-year deployment. And it's on a rolling basis. So, the meters themselves will have to be physically switched out from the old analog meters, or even in some cases, digital meters to the advanced meters, the smart meters.

And that will occur over time with 530,000 customers in an area--the size of our service territory is pretty big. So, it will take some time to deploy that to all customers.

But in addition to that, at the same time, we have the other areas in blue {on this Slide} which are the distribution upgrades, and then the supporting services in gray that are occurring at the same time.

So, the time everybody is fully transitioned to the new meters would be roughly around the end of year four of this plan, beginning after the Commission makes that decision.

Technical Session #8: November 2, 2022

Member of the Public: Decentralization of Demand

Where in the futures and sensitivities models do you factor the possibility of decentralization impacting demand for PNM services?

Initial Response: PNM

Do you mean decentralization of resources or decentralization of load? Could you clarify?

Member of the Public continued.

It just seems that looking far into the future, where the possibility is of people to kind of fork off, requiring PNM or backing up at home with their own batteries, all that kind of thing.

It may be too early, but I just keep wanting to see that somewhere rattling around in our thinking because customers could peel off in different ways. And that could impact the company in many ways. So, it's probably demand.

PNM continued.

Thanks for clarifying.

The way that this is being considered is through our demand forecasts. The IRP, again, looks at just PNM's retail customers. If a customer were to become completely self-sufficient, and no longer be a part of the PNM's retail system, they would not be included in the load forecast. That's not an obligation we would have to serve.

If the customers are incorporating their own resources behind the meter through additional adoption of behind the meter photovoltaic (PV) rooftop solar, essentially adding their own batteries behind the meter, those are things that we are incorporating through the load forecast.

So, we have a specific component in the load forecast that assesses a forecast of behind the meters: PV adoption. And there's going to be four or maybe five different behind the meter PV forecasts. One of them will be trying to back out all existing PV on the behind the meter PV on the system. One will be assuming there's no new incremental behind the meter PV, Then, there's going to be three different incremental behind the meter PV forecasts.

And so, each of these forecasts can be used as modifications to the overall retail load forecast and would reduce the amount of system requirements that would have to be added and, in turn, reduce the amount of retail sales to support those customers. That would be accounted for--with additional behind the meter storage additions.

Again, that would end up depending on how [those modifications] are operated. If they are operated just on behalf of any individual customer for their own benefit, that would manifest through a change in the load shape in one way.

On the other hand, if we were to look at the establishment, once we have AMI (Advanced Metering Infrastructure), of perhaps a distributed energy resource management system, we can start to model the behind the meter resources as something that has full visibility--not just a load modifier, but a dispatchable combination of resources that PNM could operate or dispatch, through an aggregated system for the benefit of the entire system. Thus, that would reduce the need for additional resources on the system.

Those are the ways we're thinking about it for this integrated resource planning cycle, and we'll have to continue to think about it going forward. Additionally, there's going to be independent forecasts for different building electrification as well as transportation electrification forecasts. And then a time of use, or time of day rate pricing sensitivity that will say, "Well, if enough customers joined this time-of-day pricing program and modify their behavior, how might that change the overall requirements of the system?"

So, that's the way we're looking at, at least from the supply planning point of view. And we would always keep in mind as well, when we're establishing what the needs of the system are, and we determine that so much solar might be needed, or so much storage might be needed, even if it's coming in at the utility scale, that it doesn't mean it's something that has to be done by the utility. It could always have a part for the customer to enable them to be part of the transition, so long as the resources are dispatched for the benefit of the system, and not dispatched for the benefit of any specific customer.

We know that this has been an ongoing question for years. And we hope that [this response] helps to think about the way we're looking at it this go around, from the integrated resources planning point. The key has to be about just what are we doing for our retail customers? And then how can we take lots of small, distributed resources, and think about how they could be aggregated up to the system level. Because when we're looking at the IRP, it ss always looking at the bulk transmission system; we're not modeling down to the distribution levels.

Member of the Public continued.

Thank you.

I keep raising this because I do see things as being pretty far, some of it's pretty far, out in the future. I'm not expecting immediate answers of any sort. I just want to understand how to think about it. And you're helping me a lot.

Member of the Public: Resistance to Behind the Meter

Are you expecting any resistance to PNM's interest in getting information from behind the meter?

Initial Response: PNM

In 2016, we filed a case for the adoption of Advanced Metering Infrastructure (AMI), and there was a lot of resistance. That case was denied by the Commission, and there were a number of groups and individuals that filed protests. That seems to have changed a little bit.

The Commission, as a part of our grid modernization filing, required us to file our AMI component. If they approve it and they require AMI to be the de facto standard meters of the system, that will be deployed, and it's met with some resistance, we're not sure necessarily what the company would do for individuals who may not want that type of meter.

But we certainly see that going forward. AMI--advanced communications--will be a significant component and part of the infrastructure of the system. We can't decarbonize completely; we can't do

all the things on the distributed level--things that we need to do in order to decarbonize--without having that visibility into the edge of the system.

PNM Update

Our Grid Mod filing identifies the opt-out options and fees proposed by PNM – a customer will pay a one-time fee at opt-out, and then a recurring monthly fee for meter maintenance and manual reading. If a customer opts out prior to deployment, they will keep their existing meter; if a customer opts out after deployment, the new meter will be replaced with the same type they had before AMI deployment.

Grid Mod FAQs are posted on PNM's website here.

PNM is also voluntarily adopting the U.S. Department of Energy's Data Guard Energy Data Privacy Program Voluntary Code of Conduct. (https://www.smartgrid.gov/data_guard.html).

IRP Report

Kick Off Meeting: April 28, 2022

Member of the Public: Load Served and Connected Load

Please distinguish between load served and connected load and be consistent in the IRP.

PNM Response

We will ensure that a scenario that removes BTM-DG [Behind the Meter Distributed Generation] is included in the IRP.

Customers are free to do what they want and what they do behind their meters makes it hard to know what those loads are. We don't have intelligent meters, and we can't know exactly what the fully connected load is.

The load the utilities serve is what is seen at the meters by the utility. For those individuals or commercial entities that have BTM rooftop sources, serve part of their load.

What is the total connected load before being offset behind the meter generation versus what is the load served by the utility?

Presentation: May 25, 2022

E3 (Energy + Environmental Economics)
"Resource Adequacy in the Desert Southwest"

Member of the Public: Adequacy of Best Practices With Increasing Electrification

It's entirely possible that you could add up the best practices and they would not meet the adequacy that we might see as we try to electrify so many things. How did the study deal with that?

Initial Response: E3

We built this study around a specific load forecast that was developed based on the utilities' own assumptions as to the future of transportation, electrification, and such. Our work here represents an evaluation of, given a certain load forecast, the resources that the utilities have planned and have in the ground today that are sufficient to meet that load forecast to a sufficient standard.

That means there is a lot of pressure on the utilities in their load forecasting to make sure that they're keeping up with the trends that we're seeing within the industry with respect to electrification, both transportation and buildings, and that the load forecasts reflect the best future information we have as to the size of those growing segments. As the question alludes, if those dynamics aren't captured in a forward-looking evaluation of how large loads could grow, there may not be sufficient resources developed in the plant to keep pace with those changes.

PNM continued.

We would want to ensure that E3 agrees that part of resource adequacy planning is to ensure that this resource adequacy standard has sufficient room to cover uncertainty around that load forecast and that always carries enough reserves to cover that uncertainty with the load forecast and a number of other variables.

E3 continued.

Agreed.

Member of the Public: Water Shortage

We're a water shortage region. How has that come into planning?

Initial Response: E3

It affects the planning in a number of respects, some of which are not taken into account directly within our study, and some of which are, certainly, as water becomes more and more constrained within the region. And that may have impacts on economic growth within the region. That's something that you would expect to see show up within utilities' load forecasts--their expectations for future economic growth.

We've taken previous load forecast from utilities at face value, so we haven't made any assessment or judgment as to how water use within the region might impact those forecasts. But we think that is something that we would expect utilities within the region to be thinking about.

On the supply side, the risk of drought is something that we did try to think about and factor directly into this work. Essentially, within a model like this loss of load probability model, we have some representation of how much energy is available from the region's hydro resources. And the amount of energy that's available, you can imagine, is a function of what the underlying hydro conditions are.

What we tried to do, and this is based on input that we've gotten directly from the Western Area Power Administration and the Bureau of Reclamation, is characterize the relative risk of severity of drought in a probabilistic way, such that there's some probability in our model that you end up in a really critical hydro situation that reduces the value of the region's hydro resources. In some cases, you may be in a more normal condition on a relative basis, and you have a little bit more capability. So, on the supply side, that's how we would expect that to come into play.

PNM continued.

From PNM's perspective, looking at the resource plans that were in our 2020 IRP and the types of resources we're looking at now—and this is pretty true broadly across the West—the new resources that are coming on board are much lower water use resources than the resources that are being retired. So, when you think about coal plants have steam boilers being retired and replaced with solar storage, maybe aeroderivative, and natural gas turbines that run very infrequently and that don't require much water, the net water usage for electrical power generation is significantly decreasing, say, for any entity building a pumped hydro plant or something like that.

Office of the New Mexico Attorney General: Expected Availability of Existing Legacy Resources

[Regarding] the expected availability of existing legacy resources--the existing coal and gas plants--there's a lot of attention around the declining ELCC's for renewables and how they fall off as penetration increases. Was there consideration about how the availability of existing resources decreases as they age or was that outside the scope [of the study]?

E3 Response

On the risks associated with existing or legacy resources, a model like this relies on assumptions around the risks of outages for all types of resources, existing resources included. And those outage risks are usually based on historical experience. In this study, we've used assumptions that are consistent with utilities' plans for the outage risks of various resources. In general, what we see with those outage rates is that for a lot of the oldest plants on the system, and in particular, some of the coal plants, those outage rates are higher than you might see with a new facility. And so that is factored into this type of analysis.

And we do, in fact, in this study, apply the same ELCC [Effective Load Carrying Capacity] construct that we use for wind, solar, and storage to those existing resources when accounting for their capacity contributions. So, every one of those resources--whether nuclear, coal, or natural gas--gets its own haircut on its effective capacity based on assumptions around its outage rate.

PNM will discuss outage rate assumptions for its modelling in a future session.

Member of the Public: Storage of Water

What kind of changes could be made in the storage of water? There are many cultures that store water underground, pipe water underground, or have open systems where evaporation is a major issue. Is that something that tangentially we need to address or get put into the conversation?

PNM Response

I think there are two different pieces to that, if we're thinking about being able to add water-based resources or about the hydrological resources included in the studies that have reservoirs. Is there a way to take those two closed systems as opposed to open systems to reduce the evaporation?

So, those are things that are being looked at in terms of a few pumped hydro projects that we are aware of. And there are different ways they think about either reducing or eliminating evaporative offtake from the system as a whole: Are you trying to say now that every single water reservoir should be for the entire economy or for water usage for homes or for anything other than power generation? That's a much broader discussion.

If we're going to try to get the entire economy to go a certain way, we've got to stop thinking about individual sectors and start thinking about the cross play between sectors. But that's probably a broader discussion than we have time for in these integrated resource planning forums.

Granted, if we're going to make the best use of our water resources, especially as things are becoming more constrained with more population growth in the West, existing or new hydrological resources in the form of pumped storage is one of the most well-known types of long duration storage you can add to a system; it could really play a role. But if you don't have the water for it, then what's the use? So, we've got to figure out a way to make everything work for us in an efficient and environmentally friendly way.

TECHNICAL SESSION #1: June 8, 2022

CSOL Power: Storage

I just wanted to make sure that you're going to go over the storage requirements that you were looking for. [I'm seeing] 5-hour with 500 megawatts, and I would like to know how often that's expected. [Perhaps it was related to an RFI.]

PNM Response

We do have two RFIs out right now, neither of them is specific to a duration aspect. One of the RFIs is seeking longer duration storage. And that can be anything from maybe five hours—some consider that long; it is longer than four (4) hours, but it could be eight (8) hours, 12 hours, 24 hours, a week, or even longer. We're very open ended in that RFI, and there's no prescribed capacity amount, either.

We're trying to get an idea of what is out there, especially those types of projects like pumped hydro or other things that have very long lead times for the development of those types of resources. Or maybe they're getting to the stage of being commercially viable, but they're still in pilots; we want to understand them and then get a better idea of how the commercialization of those types of resources would go.

The other RFI is more about emerging technologies, and very similar to the RFI that we issued prior to the 2020 IRP to look at those new and emerging technologies that are less project specific, but more technology specific, that we can start to consider over the planning horizon.

The IRP, of course, is about resources and storage capacity durations. Do we need to stop thinking about storage in the duration, but more about the total amount of stored energy that it could offer up? Then, you've also got the capacity side of the equation. Say, we've got 100 megawatts for a battery. Well, that 100 megawatts can be discharged at 50 megawatts, over eight (8) hours.

So, there are different ways you can utilize these storage technologies and make them look a little bit different. But there are going to be times when you might want to have that greater rate of discharge or charging. In winter, there's a shorter window for solar production, so, if we need to charge our storage devices, we might need to have a higher rate of charging capacity, even though the total volume of stored energy may or may not change.

The IRP is going to address how we start thinking about the resources we need to reliably serve our customers in a cost-effective way. I don't think there's a prescribed volume of duration of storage or capacity of storage that we've identified yet. We will be identifying that through this IRP process.

TECHNICAL SESSION #3: July 6, 2022

InterWest Energy Alliance: Increase in Hot Days Per Decade

It would be helpful to repeat this discussion in writing somewhere--the amount of increase per decade and the fact there are fewer cold days, more than hot days. Will there be a detailed report written?

PNM Response

We can certainly take that feedback and try to organize it into a write-up in the IRP itself. It shouldn't be too tough to do.

Typically, the more detailed discussion of the weather data and the load forecast development is in the Buildings Appendix C of the 2020 IRP.

Load & Energy Efficiency Forecasting

Kickoff Meeting: April 28, 2022

The Public: Effect of Proposed Changes on Sub-populations

What sub-populations of the PNM customer base are going to be impacted and in what order? How do we keep that in balance, both for the system and as we have more distributed generation? How does that change the role of the grid and other factors?

See the discussion in Grid Modernization (Grid Mod).

CCAE: Effect of Partner Systems' Renewable or Battery Storage

As partner systems in southwestern states move to renewable or battery storage sources of energy, how may that affect the sales of energy to PNM … or as regional utilities or regional load serving entities transition their systems towards more renewables and energy limited resources, will that impact PNM's ability to purchase energy on the wholesale market?

Initial Response: PNM

We believe this will impact PNM, and we are going to be taking a look at that much more closely.

We've been seeing a decrease in liquidity of the markets over the last few years and expect to see that continued decrease going forward. If all of the utilities in the desert southwest start having systems that are mainly solar and storage-based with a little bit of dispatchable natural gas for reliability, depending on the timeframes, the systems will become much more correlated in terms of when their risks are going to manifest.

If energy storage is the primary resource used for reliability, especially if it's shorter duration, there could get into situations where other utilities may not want to sell energy out of their stored resources because they would be unable to replenish that energy and use it for themselves later.

So, we do see a pretty big risk that we need to examine going forward related to what the energy markets are going to look like and how those dynamics will evolve as more and more systems go to your heavy deep decarbonization requirements.

Presentation: May 25, 2022

E3 (Energy + Environmental Economics)
"Resource Adequacy in the Desert Southwest"

CSolPower: Electrification of Vehicles

Will the electrification of vehicles be included in this IRP process?

Initial Response: PNM

We will be discussing this in October in the Grid Mod presentation.

Office of the New Mexico Attorney General: Load Forecast

The study took the load forecasts at face value rather than evaluating them, and then mentioned 2% load growth. How much of the future need is driven by this expectation around high load growth? I certainly understand electrification and EV load. But some of the load growth, generally, was for population growth and industrial load. And there have been patterns of historically over projecting load growth that doesn't materialize.

Initial Response: E3

On your first question, we didn't go through an exercise of trying to disentangle exactly how much the various factors of load growth versus resource retirements drive the need for capacity within the region. But it's hard to say it's not a combination of both and that both are really significant contributors.

We found that in 2021, the system is already right on the cusp of being at the acceptable level of reliability if you were to use a one day and 10-year standard. At that point, any resource retirements or any load growth beyond that point drive a need for new resources.

Now, in terms of scale, the study points out that by the time we're out in 2033, we're looking at somewhere on the order of 5 to 6000 megawatts of conventional capacity that's expected to retire. So, at the very least, you can imagine that that would be some sort of a bookend or approximation of a portion of the need that might be set by, determined by, or associated with resource retirements.

Member Of The Public: Demand Response

Is demand response, for lack of better words, curtailment of the load at the demand level? Are those distributed resources or those that are actually generating? The curtailment of load is not considered in the one in 10 or two in 10, right?

Initial Response: E3

That's demand response programs contemplated by utilities; essentially load that can be curtailed under specific conditions, typically when the system is tight on capacity. Demand response calls are not counted as loss of load events.

Technical Session #2: June 22, 2022, Presentation

AEG

Energy Efficiency Study

Brubaker & Associates: Miscellaneous End Uses

Is the Miscellaneous category just everything that doesn't fit into the other categories?

Initial Response: AEG

Yes, it is a kind of the catch-all for all the things that don't have a place in the other end uses.

Sandia National Laboratories: Conversion Rate of Evaporative to AC

Do you assume in your baseline load forecast this conversion rate? Over time, is what actually happens that difference could be due to energy efficiency incentives or incentives to not convert to AAC? Can part of it be forecast error? Does all of that get counted as energy efficiency?

Initial Response: AEG

Every forecast has error. This is a projection, so it could be over or underestimating the conversion rate. The actual energy efficiencies that occur could be in error, either be too much or too little energy efficiency once we actually get there.

That transformation happens as people are really moving away from evaporative cooling. It could go in either direction. It just depends on which way the actual adoption happens, because we could overshoot it, or we could undershoot it in our forecast.

And with all the codes and standards, there are so many things that are going to come into play in the future that change those adoption rates. There's electrification and things like heat pumps happening in the in the HVAC space. Lots of little wrinkles.

There will be another session on energy efficiency, as well as a customer program and a session on rate design.

Sandia National Laboratories: Conversion of Evaporative Cooling to AC

Is there a trend happening around the conversion of evaporative cooling to air conditioning? Do you assume in your baseline load projections about what that conversion rate might be?

Initial Response: AEG

The short answer is yes. We are collecting information on that kind of conversion from the past. We've done primary research, and we are looking at the saturation of different types of cooling within the residential sector. So, we do have some history to help us make that assumption.

We are looking at a lot of different sources to understand how saturations change over time, and then we will build that into the model. The potential for energy efficiency is changing, as you're seeing more and more HVAC, regular air conditioning coming into PNM territory.

We are also going to rely on national sources and integrate with Itron. They are also making assumptions, using a statistically adjusted end use modeling approach that actually uses indices of cooling and heating.

There will be another session on energy efficiency, as well as a customer program and a session on rate design.

Sandia National laboratories: Demand Side Management

Demand side management is not being considered as part of energy efficiency, correct? Are you asking about demand response -- that is some sort of customer response based on some sort of price signal or program?

Initial Response: AEG

That's correct. Demand response in the traditional sense, pricing or smart thermostats that are being controlled through signals during peak periods that are targeting only demand, is not part of what we're doing in the energy efficiency potential study.

We did that kind of study in 2019 for PNM. There is a lot of overlap because things like smart appliances, or smart thermostats, or things that can be energy efficient can also be used for demand response.

We actually do estimate peak impacts for the equipment that's installed but we are not talking about the programmatic context in which those pieces of equipment can be controlled in this study.

Initial Response: PNM

Consider this scenario: A smart appliance could have a thermostat control, with an energy efficiency component allowing it to be part of a demand response program where you could turn off power to it given a signal coming from our demand response. What if there are new rate designs with real time pricing, with time of use rates or other things that could also influence customer behavior and shift the way customers are utilizing energy creating differences in the load patterns?

That's actually a sensitivity that we've done throughout the load forecasting work we are doing. There are lots of different things going into this and trying to figure out where they fit in is as important as what the impacts are going to be.

There will be another session on energy efficiency, as well as a customer program and a session on rate design.

Sandia National Laboratories: Hourly Estimates of Savings

Will the hourly estimates of how much energy savings is going to happen based on each of the bundles include, for example, smart thermostats and other demand response programs?

Initial Response: AEG

Yes and no.

It will include a smart thermostat. For example, it is done by measure, and then by end use. We take a measure and map it to the end use. For a smart thermostat, we would be mapping that to a cooling end use. We take the total energy savings assumed to occur over a year and then map that to an end use load shape.

We have calibrated load shapes that are unitized, and they match PNM's system load shapes based on the sector. So, they all add up so that when we get a peak, it matches their peak.

We take the total annual consumption and multiply it by unitized load shape, and then get an estimate of the consumption that's being reduced or the savings in every hour. It matches the cooling load shape.

We don't make any assumptions about changing that cooling load shape based on a program.

So, yes, we would use smart thermostats but no, we're not making any assumptions about how those maps or smart thermostats would change the actual load shape or the timing of the load based on signals that are being sent.

Initial Response: PNM

We would model demand response separately. Say, a smart thermostat program is a demand response program that we would model. Absent the calling of that program, there's still some energy efficiency savings from that appliance, but clients could also allow them to participate.

If the model selects a demand response program, when it goes through the production cost dispatch, and gets to a point where the demand response program is called, you then see within the model that demand reduction in the production cost, and that would be on top of the already reduced low chamber associated with the energy efficiency measures.

AEG continued.

It's a little tricky because they're two separate pieces. And even though some programs aren't really integrated, we're still in a world where we're modeling them separately.

PNM continued.

Everything is changing and changing rapidly. The models are trying to catch up.

There will be another session on energy efficiency, as well as a customer program and a session on rate design.

NV5: Modeling Electric Vehicles

How do electric vehicles fit into the modeling?

Initial Response: AEG

We are not modeling electric vehicles in the energy efficiency potential study. That is something we are doing more and more often as part of an electrification layering in an electrification forecast. It could be the beneficial electrification of appliances, or it could be EVs, but it does require a forecast of EVs to be to be layered in.

It's not really energy efficiency. It's more load building or electrification. It's not part of the scope here, but definitely something that we're thinking a lot about and seeing and doing in other places in in the country.

Initial Response: PNM

PNM has a transportation electrification pilot program, approved by our commission, that's going to be implemented over the coming years.

In the 2020 IRP, we had three separate transportation electrification scenarios that we modeled in our load forecast: a low, a mid, and a high that corresponded to different electric vehicle adoption rates. We had building electrification sensitivities as well. We had something over 80 different scenarios that we had run in sensitivities. We were testing, inter alia, the effects of changes in building electrification,

transportation electrification, adoption rates, changes to behind the meter, and solar adoption rates. These scenarios will get worked into this IRP's load forecast, which Itron will be discussing.

On the August 25, 2020, meeting slides, as well as in Appendix C of the 2020 IRP, we showed the breakdown of the load forecast that shows all of the different scenarios. For the load forecasts that we did, it'll show the transportation application. The building electrification will show the time of use sensitivity where we implemented more dynamic pricing signals and behind the meter solar PV adoption rates.

The August 25, 2020, presentation has a complete breakdown of the energy efficiency bundling. It shows not just the single year AEG used in its example but also a number of other pieces if you want to get an idea of what we are looking at for those and how they were working with the modeling. There are detailed write ups in that presentation about which bundles were selected, which ones were not selected, and virtually all scenarios; anything under $50 per megawatt hour was always selected. And then, depending on which scenario we're talking about, sometimes more expensive bundles were selected.

We are starting with the 2020 framework and trying to figure out where we can make incremental updates improvements and incorporate more information to make sure we're tailoring the IRP to what's important to our stakeholders.

CSolPower: Rooftop solar

Does rooftop solar count toward energy efficiency?

Initial Response: PNM

No. Per the Efficient Use of Energy Act, energy efficiency is defined as "measures, including energy conservation measures, or program that target conservation behavior, equipment, or devices to result in a decrease in consumption of electricity and natural gas without reducing the amount or quality of energy services." Since rooftop PV does not result in a decrease in consumption of electricity, it does not qualify as energy efficiency.

Technical Session #3: July 6, 2022

InterWest Energy Alliance: Impact on Night and Early Morning

Do you plan to do a comparison of the impact on the night and early morning hours? I would assume that demands at that time are much lower.

Initial Response: PNM

The demands are much lower, but it doesn't alleviate the demand that's needed right after sunset. You can't just consider a very short window; you need to think about the overall system dynamics: The utility has to have enough resources under its control to meet its net peak, including reserves. But then, at some point, it's not just about that net peak and the capacity associated with that. It also becomes the amount of stored energy and the amount of energy that you need to be able to carry forward overnight into the hours of the morning to be able to sustain meeting your loads.

We are going to present another reliability analysis, looking at what the risk hours are and showing what that is as it changes over the time frame of the study--2023 through 2042.

When we presented the (preliminary) ELCC [Effective Load Carrying Capacity] analysis, we talked about doing an ELCC analysis not just at a static point in time, but at a couple of different points in time throughout our forecast horizon, showing, that as the risk hours change, the effective load carrying capability of a given resource to meet those risk hours will change.

So, the amount of resources we're going to have to add over time is going to increase because the solar, the wind, and the storage are going to be adding less and less ELCC as their levels of penetration increase throughout the period of decarbonization.

Furthermore, you're going to have to deal with not just that net peak, but also the flattening of the net load as it wraps around into the early morning hours.

InterWest Energy Alliance: Peak Need

Is your key need, especially during summer peak, going to be capacity or energy in the 6-9pm window, so what happens when you thicken that self-generation slice at the top (Slide: “Hourly Load on Peak Day”) that just pushes your peak into the evening hours when the sun is going down or down? Is that right--partially-- so that this is just a snapshot and doesn't represent the full system dynamic?

Initial Response: PNM

Yes. And whether it's behind the meter solar or utility solar or utility scale solar, the more of it that we add, the more it's going to depress consumption that is not served by solar in the middle of the day. But the requirements that we have to serve when the sun starts to set are going to remain at those higher

levels. We're going to have to have resources to cover that, depending on what else is added to the system, because you can't think about it as just solar, as you start to add more storage.

In the 2020 IRP Appendix M, there are some heat maps of the loss of load risk hours: As you go further down the decarbonization path, as you add more solar and then add more storage, the storage has the tendency to flatten out that peak, but you can only operate for a limited duration.

The solar will push the capacity needs into the early evening period. And then, as you add more storage, it's going to further shift that risk later into the evening overnight, eventually into the early hours of the morning.

So, you can't just think about it as this really short window in the near term. If we only had solar, it's going to be this near-term short window, but as we go further and further down the road, you're going to start to see that loss of load risk. And you can see this even in the presentation that E3 did on its Southwest study: The overall loss of load risk for the southwestern region by the time you get to 2030-2033, if all the utility IRPs are followed, you start to see that loss of load risk start to creep into overnight and early mornings because of the duration and limitations on energy storage.

InterWest Energy Alliance: Heat Wave Analysis

The heat wave analysis that we're talking about here will likely have some input into the broader analysis that you've just summarized. If that's the case, if that's, if that's true, then I think that some of the assumptions that we've been talking about your today need to really be explained clearly so that we all understand what the cascade of assumptions is.

Initial Response: PNM

[Perhaps we can continue this discussion offline to clarify how you're thinking about this presentation's use of weather variables in the development of the PNM retail load forecast.] This does not concern neighbors, or what our availability to purchase power from them is.

New Mexico State University: Heat Waves

We've heard that the average temperature in New York or for PJM (PJM Interconnection LLC) was going up .7, and we don't really know what the trend is for New Mexico. I'd like to see a scenario that does take into account increased heat waves, the increased occurrence of heat waves in the summer, because that's what's going to stress your system. So, can we look at the trends we know about in New Mexico, project out increases in heat waves, and make a scenario for that?

See Reliability, Resiliency & Resource Adequacy.

Member of the Public: Elasticity: Behind the Meter (BTM) Solar, Community Solar, Electricity Rates

Is there any elasticity between behind the meter solar and community solar and electricity rates? If so, is that a significant factor?

Initial Response: PNM

We'll have to have one of our rate design folks address this as well.

Initial Response: Itron

It's pretty complicated, right? Behind the meter and community solar is behind the substation anyway. We're not saying it doesn't necessarily change how much energy people are using, but it changes how much the utilities deliver. And, so, as it reduces the amount that utilities deliver, it reduces the amount of revenue they recover--if it's a volume based charge, not so much if it's a demand charge.

That means for residential, where you still have sort of a volume base charge, you're recovering less of your fixed costs, because you're delivering less energy, and, therefore, you're going to have to raise the prices to recover the revenue to cover those fixed costs.

So yes, there's definitely a relationship there and we are sure the rate people are working on that to find ways to make the system work financially.

PNM continued.

We'll have our rate group talk about that a bit as well. I would suspect that if there was a change in the way net metering rate works for residential, for example, you would see a reduction in the amount of folks that are trying to put behind the meter solar residentially. Because of the size of the credit paid to those customers would change.

We do think you will have to look at that if you want to properly incentivize behind the meter storage or distributed storage. Right now, our block rate is 8am-8pm. That period is too long, and the net energy metering rates potentially too high, to incentivize someone to add storage as well.

InterWest Energy Alliance: Commercial Industrial Behind the Meter (BTM)

Is there much or any behind the meter by commercial industrial customers? And how does that affect your analysis? (“Comparison 2022 vs 2020” [Non Residential and Residential Capacity Forecast slide] Slide presented was preliminary. Final numbers will be updated and posted in a future presentation.)

Initial Response: Itron

If you look down below, probably about right now, a quarter, maybe 30%, of the generation is nonresidential.

There's quite a bit in the water customers--water utilities that generate some of their own power. There's some in small commercial and general power categories. And then some of the really big customers actually have their own solar farms, but those are not behind the meter: Their solar farms are located near the transmission system somewhere and are putting the energy directly into the transmission system.

So, the really big non-residential solar generation often is not behind the meter, but there are entities like hospitals and some schools with parking lots covered with solar.

NM RETA: Residential Behind the Meter (BTM)

What factors contributed to the forecast and increased residential behind the meter capacity?

Initial Response: PNM

We'll have one of our internal subject matter experts come in and talk about some of the specific drivers behind that. We'll make sure to keep that on the agenda for a Load Forecasting meeting in November.

NM RETA: Solar Generation

Why does the minimum and maximum difference each year increase significantly? ("BTM Solar Capacity and Generation Data" Slide presented was preliminary. Final numbers will be updated and posted in a future presentation.)

Initial Response: Itron

That's a monthly cycle throughout the year.

If you put in twice as much generation, everything is twice as big. And so, the minimum is twice as big, the maximum is twice as big, and the range is twice as big. If you have twice as much solar, it's going to double the maximum generation; it's also going to double the minimum generation.

So, the gain is twice as big during the year, going from winter to summer. The winter generation is low because the days are short. The summer, the generation is high because the days are long. The biggest generation is usually in April or May, so that might show up in the June bills. As it gets hotter and hotter, the generation becomes less efficient--more light, but less efficient.

New Mexico State University: Rate of Climate Change

The question here is climate change impacts the U.S. at different rates, depending upon the region. What is the trend? What is the trend in the Southwest versus New York, versus PJM (PJM Interconnection LLC)?

Initial Response: Itron

I've seen some national lab studies, but I don't know right off the top of my head.

Initial Response: PNM

We can try to pull together some of that trend information but our focus in this IRP is about PNM's service territories. We're making our focus our weather and our load forecasts. PJM is outside the context of PNM's resource plan.

InterWest Energy Alliance: Increase in Hot Days Per Decade

It would be helpful to repeat this discussion in writing somewhere--the amount of increase per decade and the fact there are fewer cold days, more than hot days. Will there be a detailed report written?

See IRP Report.

InterWest Energy Alliance: Billed Sales Data

Why use 2015 to 2018? Why not use more recent billed sales data? (Slide 15)

Initial Response: Itron

That's not a bad idea. It's certainly something that we could take a look at to see if anything's changed significantly relative to 2015-2018.

This is just doing the weights. Those weights are something that could be updated. We will look at whether we're going to do that or not.

PNM asked question.

Could you provide a little bit of additional context in terms of how the weights, or the weather variables are done? You're coming up with a weighted average weather variable that represents the PNM system, so what this would be really getting to is, has the load growth in the system proportionally changed such that the weighted variable for weather would then change because of that?

Itron continued.

If you look at the weights, like Albuquerque, on the cooling as 77.8% weight, that was based on that 2015-2018 billing data. So, it might be a little different--bigger, smaller, probably a little bit bigger.

Brubaker & Associates: Load Forecast

I know this is preliminary. This is obviously a very big change, particularly on the residential.
What are the big drivers of this change? (“Comparison 2022 vs 2020” [Non Residential and Residential Capacity Forecast slide])

Initial Response: Itron

This change is driven mainly by the high level of activity in the last couple of years. As a result, the new solar capacity values (red line) start diverging from the old values (blue line) before the forecast begins. The higher level of historical additions put the forecast on a different and higher path.

We’re not sure of what all the logic is that goes into that in terms of government, attitudes towards solar, and government money and so forth. So, there are a lot of things that go into it, we’re sure.

Brubaker & Associates: Components of Forecast

What are the components? Are you using government forecasts? (“Comparison 2022 vs 2020” [Non Residential and Residential Capacity Forecast slide] Slide presented was preliminary. Final numbers will be updated and posted in a future presentation.)

Initial Response: PNM

That forecast, at least the near-term piece, was developed by PNM’s internal customer programs and customer behind the meter internal department. We can have them answer the question; we've already got a meeting set up.

In 2020 or 2021, we might have underestimated the amount of rooftop additions that year by 50%, so there's just a very, very strong uptick in the amount of customers who are trying to add behind the meter solar—there’s a lot of folks in the queue.

This was raised at our kickoff meeting—there’s some reworking the interconnection manual that will hopefully make it easier for folks to interconnect. All of those things are going into the change in the forecast from the behind the meter perspective.

Brubaker & Associates continued.

So, then I guess, what you're saying is that Itron received an input for the capacity growth that came from PNM?

PNM continued.

Yes.

Brubaker & Associates continued.

It would be great considering how much change is going in this versus 2020, We'll cover that in a future session. We have a further explanation of when there was shortfall. Let's understand how the projection over the time was developed.

PNM continued.

We can add that to our list.

In a future meeting September/October, one of our representatives from our customer account groups--who's really in charge of doing the behind the meter forecasting and oversees a lot of the customer requests and their connections--can talk about the uptake that they've been seeing, and the sheer demand for interconnection of behind the meter assets.

PNM: 50/50 Weather Forecast

Has anybody started using a 50/50 weather forecast for their work? Are they starting to look at 75/25? Or 90/10? Is anybody starting to ask for anything other than a 50/50 weather scenario to look how should we be planning as we start to recognize more and more what's going on with the changing climate?

Initial Response: Itron

The most interesting work is done by PJM, the transmission system operator up in the Northeast. They take each 30 years, but they take each of the last 30 years, of actual hourly weather data, and run it through. They've got an immense service territory. It could be cool in Chicago and boiling in Virginia, so coincidence is a real issue for them in terms of their overall system load.

Their way to deal with that is just to take the actual year of historical weather data for all the stations, and run them through the models, a model of what's going to happen next year, or in 10 years--run 1995 through, run 1996 through, run 1997 through--and when those patterns go through, you've got a different load forecast for that future year. You can post process those forecasts. They were doing that with daily models of zone peaks, and now they're looking at moving to doing hourly modeling.

So, that's the most detailed approach to understand the range of outcomes that you can get today, or in 10 years, with those various weather patterns.

That doesn't deal with the trend issue but the range that you can get today. Given that, just looking at the past history, that range includes anywhere a trend could take us in terms of the middle point. The middle point is moving slowly; the range around that is big at any point in time.

Understand that range is the key. The one scenario that Itron would do is going extreme--Let's find the most extreme weather and do an extreme weather run, an extreme year.

We're pretty focused on a summer peak for PNM, at least now, but an extreme year would be a year with a cold winter and a hot summer. Or maybe it's part of two years that accomplishes that.

Brubaker & Associates: Hourly Weather Data

Is the hourly weather data, both the temperature data and the global horizontal irradiation, assuming that's all in sync on an hourly basis?

Initial Response: Itron

Yes. The actual observations are from NOAA. They usually make them about 10 minutes before the hour. And so, the number that you're getting for an hour, say, from noon to one clock, might come about 1250. So, it's highly synced in that sense.

The challenge is doing the forecast to keep that synchronization in place, so we do pick one weather pattern for all the forecast years, and just map the hottest day, the second hottest day, third hottest day, fourth hottest day, to that consistent pattern through time?

The global horizontal radiation data that goes with the hottest day is from what that looks like on the typical hottest days each month.

We've gone to painful efforts to keep that analysis going. It's not easy but it's something you want to do.

Technical Session #4: July 27, 2022

Member of the Public: Distributed Generation

How would increased distributed generation, especially if it has some backup storage of its own, be factored into the modeling?

Initial Response: PNM

This question relates to the load forecast discussion we're considering. From the IRP perspective, we don't model the distribution system; we're modeling the bulk electric system. If there are distributed energy resources--let's just use behind the meter PV, for example--we do have an explicit behind the meter PV forecast that is developed in the process of developing our load forecast.

One of the things that we're thinking about doing that we don't have right now is, if we were to say, install a distributed energy resource management system, as well as have AMI [Advanced Metering Infrastructure], and the necessary grid edge technologies, which would give us visibility into the edges of the system. For example, right now, we can't see, specifically in real time, what individual customers

have in terms of behind the meter generation, what's being consumed by their loads, and what's being delivered back to the grid. That's because we don't have AMI and other technologies on the system.

If we can get those systems in place, then we can have a better representation of your customer sign up and a better control of, say, behind the meter storage resources. One of the things that we'd be looking at is: What's the total volume or total penetration level of behind the meter PV that's on the system, and then, what's the total amount of behind the meter storage on the system that would be potentially coupled with some or all of that behind the meter PV?

If we had a DERM (distributed energy resource management) system that gave us control over that, rather than just having the net effects of those behind the meter resources reflected in our than net load, we might move those to being modeled as dispatchable resources, where, based on the system conditions, we would see the charging the system, charging and discharging those batteries, potentially accepting or turning down the export settings on inverters, depending on what system conditions best optimize the use of that behind the meter storage.

But, if that would be done, we would be taking an aggregate of all of those individual resources and aggregating them up to a bulk representation of those distributed resources. This gets into the same thing that the modeling presentation is alluding to in terms of the detail of the model performance: We don't have the computational power to do a combined, complete representation of the distribution system and each of those resources on a 20-year hourly basis to do overall system capacity expansion.

So, we need to work towards that. We're going to have to push our vendors in terms of the way they're developing these models. We're going to have to continue to keep an eye on computational power--what new forms of computing might be out there.

But in terms of the way we would have to look at distributed resources, we'll have to look at how we can aggregate those up to the bulk level, and what devices we have on the system that would enable us to have better visibility, control, and dispatch of those resources if we do aggregate them up to the bulk level.

Technical Session #8: November 2, 2022

Member of the Public: Decentralization of Demand

Where in the futures and sensitivities models do you factor in the possibility of decentralization impacting on demand for PNM services?

Initial Response: PNM

Do you mean decentralization of resources or decentralization of load? Could you clarify?

Member of the Public continued.

It just seems that looking far into the future, where the possibility is of people to kind of fork off, requiring PNM or backing up at home with their own batteries, all that kind of thing.

It may be too early, but I just keep wanting to see that somewhere rattling around in our thinking because customers could peel off in different ways. And that could impact the company in many ways. I don't know, it's probably demand.

PNM continued.

Thanks for clarifying.

The way that this is being considered is through our demand forecasts. The IRP, again, looks at just PNM's retail customers. If a customer were to become completely self-sufficient, and no longer be a part of the PNM's retail system, they would not be included in the load forecast. That's not an obligation we would have to serve.

If the customers are incorporating their own resources behind the meter through additional adoption of behind the meter photovoltaic (PV) rooftop solar, essentially adding their own batteries behind the meter, those are things that we are incorporating through the load forecast.

So, we have a specific component in the load forecast that assesses a forecast of behind the meters: PV adoption. And there's going to be four or maybe five different behind the meter PV forecasts. One of them will be trying to back out all existing PV on the behind the meter PV on the system. One will be

assuming there's no new incremental behind the meter PV, Then, there's going to be three different incremental behind the meter PV forecasts.

And so, each of these forecasts can be used as modifications to the overall retail load forecast and would reduce the amount of system requirements that would have to be added and, in turn, reduce the amount of retail sales to support those customers. That would be accounted for--with additional behind the meter storage additions.

Again, that would end up depending on how [those modifications] are operated. If they are operated just on behalf of any individual customer for their own benefit, that would manifest through a change in the load shape in one way.

On the other hand, if we were to look at the establishment, once we have AMI (Advanced Metering Infrastructure), of perhaps a distributed energy resource management system, we can start to model the behind the meter resources as something that has full visibility--not just a load modifier, but a dispatchable combination of resources that PNM could operate or dispatch, through an aggregated system for the benefit of the entire system. Thus, that would reduce the need for additional resources on the system.

Those are the ways we're thinking about it for this integrated resource planning cycle, and we'll have to continue to think about it going forward. Additionally, there's going to be independent forecasts for different building electrification as well as transportation electrification forecasts. And then a time of use, or time of day rate pricing sensitivity that will say, "Well, if enough customers joined this time of day pricing program and modify their behavior, how might that change the overall requirements of the system?"

So, that's the way we're looking at, at least from the supply planning point of view. And we would always keep in mind as well, when we're establishing what the needs of the system are, and we determine that so much solar might be needed, or so much storage might be needed, even if it's coming in at the utility scale, that it doesn't mean it's something that has to be done by the utility. It could always have a part for the customer to enable them to be part of the transition, so long as the resources are dispatched for the benefit of the system, and not dispatched for the benefit of any specific customer.

We know that this has been an ongoing question for years. And we hope that [this response] helps to think about the way we're looking at it this go around, from the integrated resources planning point. The key has to be about just what are we doing for our retail customers? And then how can we take lots of

small, distributed resources, and think about how they could be aggregated up to the system level. Because when we're looking at the IRP, it is always looking at the bulk transmission system; we're not modeling down to the distribution levels.

Member of the Public continued.

Thank you.

I keep raising this because I do see things as being pretty far, some of it's pretty far, out in the future. I'm not expecting immediate answers of any sort. I just want to understand how to think about it. And you're helping me a lot.

Technical Session #10: January 17, 2023

NM RETA: EVs

Would electric vehicles [EVs] be a part of "Miscellaneous" [Slide 14]?

Initial Response: PNM

I believe that electric vehicles are not included in the energy efficiency portion … We take care of that in a separate piece of the load forecast.

AEG continued.

Yes, it's included in miscellaneous end use in terms of where that's showing up on the electricity profile.

PNM continued.

And then the savings piece, if we wanted to think about that, would be about changes to the chargers or how those pieces would work.

But in terms of the overall load component of EVs, that's a separate load component on a different part of the load forecast.

AEG continued.

There is some small amount of energy efficiency opportunity from putting in ENERGY STAR level 2 chargers, which I think is included in our analysis. But, yes, we're not providing a forecast of electric vehicle adoption to PNM.

InterWest Energy Alliance: IRA Incentives

Does this [Slide 14] include IRA incentives, such as for heat pumps?

Initial Response: AEG

No, we have not explicitly adjusted for any potential impacts of the IRA [Inflation Reduction Act].

I think that's a question we're getting on all of our studies. And it's great question. I think it's a little uncertain what impact those [incentives] are going to have on customer adoption. So, I think that's just something we're going to have to track in these studies to see what impact those actually have.

It's a little different in PNM's territory, also, because we are looking from the Utility Cost Test perspective. So, we're not in a jurisdiction where we were looking at the total resource cost test perspective--that might change things a little bit if it's really just bringing down the cost of the measure. But it's just unclear whether PNM would actually be able to reduce its incentives to still get the same level of energy efficiency potential or the extent to which those IRA incentives, whatever format they come through, are going to affect the baseline forecast.

PNM continued.

From PNM's perspective, right now we're talking about potential savings of some baseline that could be achieved through energy efficiency programs. The IRA incentives would also need to then be accounted for on the load side through some incremental increase in overall adoption rates of switching from, say, natural gas heating to electric heating, heat pumps, things of that nature.

And we did talk about that last time. On the load forecast side, we do have some higher building electrification sensitivities. To what extent those will be adopted by customers in the PNM service territory is unknown. We'll have to just wait and see how that develops over time and incorporate data over time.

We are going to run at least one sensitivity case on our load forecast that includes a higher building electrification scenario. It is also important to consider, should that [increase in load] occur [on our system], what potential savings could be realized on the EE side through more efficient heat pumps or other things that could lead to differences in what the load forecast would be relative to potential savings due to the types of measures that AEG is talking about here.

NM RETA: Units of Measurement

On Slides 21 and 23, are the units in gigawatt hours as on Slide 22? What are the units there?

Initial Response: PNM

Are you referring to the tables that talk about the achievable potential in 2025 and 2030?

NM RETA continued.

Yes, exactly.

AEG continued.

Yes, good question. Apologies for not labeling those. I think those are megawatt hours.

PNM continued.

Yes, these are megawatt hours, relative to a particular year, and then cumulatively, like on Slide 22, where you show gigawatt hours, you needed to convert from megawatt hours to gigawatt hours in order to capture the cumulative effect over time of those megawatt hour savings.

AEG continued.

So, these values are cumulative in this. Like on this table that shows that's shown here [Slide 23]. These are cumulative megawatt hours. It's just when we showed it at the system level; values were very large, so we converted them to gigawatt hours.

Sandia National Laboratories: Evaluation of EE Programs

I'm curious to know what kind of measurement, verification, and evaluation [MV&E] PNM has done on past energy efficiency programs, and if it has any plans for MV&E going forward?

Initial Response: PNM

We do. We are required to do a M&V (measurement and verification) report each year. Those reports are filed each year and posted on our website as well as filed with the New Mexico Public Regulatory Commission.

PNM Energy Efficiency continued.

Back in 2004, the state passed the Efficient Use of Energy Act, requiring utilities to implement energy efficiency programs on the premise that it's more cost effective to incentivize customers to use less energy than it is to acquire more supply side resources.

So, to prove that premise, at the end of each year, we have an independent measurement and verification contractor look at our energy efficiency programs, at what we spent on them, and at the

measure life; do a net present value based on the life of those measures; and compare the value of those benefits to the year one cost of implementing those programs.

So, we do [M&V] every year. That is a public document; you can find it on pnm.com/regulatory: Scroll all the way to the bottom and you can see those reports. Only the most recent two years are posted, but if you have any historical context or interest, let us know and we'll get them to you.

Sandia National Laboratories continued.

While you were talking, I did some Googling. I think I'm looking at the 2021 report. Apologies if this is a question that would be answered if I read the whole report. Does any of the measurement and verification involve randomized control trials? I don't see any discussion of the methodology in the table of contents, so that's why I'm asking.

PNM Energy Efficiency continued.

No, they'll do regression analysis. They'll look at historical use of a specific customer and compare it to what they're doing now. But nothing randomized. We'll look at customer measures specifically and then they will do statistical analysis or just, say, based on this subset of customers, they will apply that to the whole segment if it's a large measure, like lighting.

Sandia National Laboratories continued.

I would strongly urge PNM to consider adopting what I'll call more rigorous methods for [MV&E] on energy efficiency because there are lots of case studies of energy efficiency not quite turning out how you might imagine it would from the sort of methods you're describing.

PNM Energy Efficiency continued.

Right, making a note.

Sandia National Laboratories continued.

But yes, that's going to depend on what the PRC will allow you to do, like withholding energy efficiency eligibility from half the customer base may not fly.

PNM Energy Efficiency continued.

I think that maybe a similar thing we do is in our behavior programs, where we send, just in its most simplistic form, letters to customers, or emails or texts, informing them of their customer use.

And so, our behavior programs have a control group and a treatment group. The treatment group there may be 350,000 and the control group is 50,000. So, you compare the use of those two segments, based on the information they're getting from the customers who've never got information.

Sandia National Laboratories continued.

Makes sense.

Another dimension you can randomize is the generosity of the incentive to see to what extent the utility needs to incentivize some energy efficiency measure to get a customer response, and that would then potentially change the utility resource cost estimates of these different bundles.

PNM Energy Efficiency continued.

Yes, we do a sensitivity analysis, which is basically that, and if you look at the [lighting report], they go into detail on how they perform the sensitivity of our incentive on the lighting measures. And so that's similar to what you're saying but we also have to weigh in the cost effectiveness.

So, we're trying to maximize the incentive as much as possible. Our utility cost test is 1.0. So, yes, if all our [UCT figures] were two and a half or something, then we know that we could increase the incentive and bring that closer to one to increase participation.

Modeling

KICKOFF MEETING: April 28, 2022

The Public: Hydrogen

Do you look at the various "flavors" of hydrogen and the various implications of their creation in this IRP process?

PNM Response

We can certainly talk about the different flavors of hydrogen. Everything is on the table.

If we were going to do some type of hydrogen project, it would have to be green hydrogen: something that's being produced through renewable energy resources, electrolysis of water, and then, put back through a turbine.

There are a lot of use cases for hydrogen but generating power from it is probably one of the least efficient use cases. So, hydrogen is not going to be the only solution. When you look at storage, both in the load pocket and at the meter, hydrogen might do a little bit. You're going to have to look at compressed air storage, maybe pumped hydro.

PRESENTATION: May 25, 2022

E3 (Energy + Environmental Economics)

“Resource Adequacy in the Desert Southwest”

RETA: Energy Storage Projects Stalled by Supply Chain Problems

In the last few PNM IRPs, there have been a number of energy storage projects that have been projected to happen--some estimated to be completed by this time. How many of those are hung up by

supply chain problems that have been getting in the way of the solar? Do you know about the progress of those various solar storage projects?

PNM Response

We are making regular compliance filings and a couple of different dockets related to the status of those projects. Specific information related to those projects is case number 20-00128. It's listed in the April 28, 2022, Kickoff Meeting presentation, which is on the PNM website. We are also making compliance filings related to the four projects that are replacing the San Juan coal plant. Other compliance filings are in docket 21-00215 related to some delays we are having.

These are for some of the resources that were supposed to come on in 2023, related to the Palo Verde lease return and associated resource procurements to replace and expand the capacity needed to serve our system in that timeframe.

Currently, none of the San Juan solar hybrid projects are slated to make their original expected online dates, which were supposed to be June 1, 2022.

PNM has entered into a few different market purchase contracts, and we've gotten permission to run the San Juan Coal Plant Unit Four through the end of the summer 2022 to ensure we are resource efficient for the summer, provided it is no different than we've been in years past.

Two of the projects we're expecting to be on by the end of this year, or very early next year, equal total 350 megawatts of solar and 170 megawatts of our energy storage. For the other two projects, it's unclear if they'll be able to make the summer peak of 2023: They're not going to be on until sometime further down the road, likely in 2024.

Between 2024 and some of the delays for resources in 2023, we're going through a similar exercise to the one we did for 2020. Canvassing the market, we recently issued a couple RFPs for delivery in 2023 and 2024 to see what's out there and ensure that we're going to have sufficient resources, subject to those previous approved resources, which are now delayed.

There are different reasons for what is causing the delays, some of which you can read about in the compliance filings. Part of the cause was that we didn't get timely approvals to bring those resources on.

Part is due to the supply chain issues. Yet another part is related to developers who could not deliver on their promises and are transferring ownership of those projects over to different owners.

The supply chain delays are predominantly related to solar. The [U.S.] Department of Commerce is investigating solar dumping, which has made a lot of developers unwilling to commit to prices and making it much harder to get the panels in place in time.

Looking at energy storage, lithium prices are going through the roof right now, which is tied to the automotive industry. A large spike in the price for energy storage is expected in the near term.

Solar and batteries are paired projects. You've got to have the solar combined with the batteries in order to get the tax credits. If you can't get the solar, the developers aren't willing to bring the batteries on and forego the tax incentives that were making those projects potentially economic.

We see a number of drivers and we're going through a number of different exercises to make sure that we're going to have sufficient resources to serve our customers. We feel pretty good about this summer, but we still have some work to do for next summer. We're going to be continually reporting to the [Public Regulation] Commission on our actions.

TECHNICAL SESSION #1: June 8, 2022

CSOL Power: Scenario Form

Will the proposed scenario form allow for different scenarios? And what kind of variables can we throw in there?

PNM Response

We are going to do our best to give you a variety of things to choose and then make some delineations. That said, the ELCC values are not going to be something that can be readily changed.

If the question is about resources—if you wanted to, say, require X amount of solar by such and such a year, that's something that we could work with. Further, if you wanted to, say, exclude nuclear from consideration from any future resources, that's also something that could be done.

There are some limitations, but we can work with what the stakeholders want to try to do, as long as it's descriptive enough.

The scenario form will also be discussed in a future meeting. See IRP meeting schedule.

Sandia National Laboratories: Varying Uncertainty

Let's say you're using 100 samples for your simulation. So, for each sample, how are you varying the uncertainty? Are you varying the profiles? Are you considering the extreme scenarios for renewables?

PNM Response

Yes. We're using a weather construct, modeling 40 years of possible weather, from 1980 to the present. For each one of those years of weather, we do a simulation with random forced outages. The construct is something like 40 weather years times many random Monte Carlo draws, giving us thousands and thousands of years, effectively, that we're simulating.

Sandia National Laboratories: Solar and Wind Profiles

How are you modeling the solar modeling and wind profiles for all the scenarios?

PNM Response

We don't try to forecast necessarily what the solar or wind will be. Rather, we use a weather year concept: For the past 40 years of weather, we model what would happen to the PNM system, in terms of things like load and solar irradiance and wind productions. For each weather year, we model if that

weather were to happen, again, what in particular, would it look like across the year? That's how we're capturing uncertainty.

CSOL Power: Carbon Free Before 2040

Can PNM consider if we are asked to go carbon-free before 2040, or 2030, or 2033?

PNM Response

That would be something along the lines of a specific scenario request: Can we set up a model to look at having an earlier carbon free requirement before 2040? That's absolutely fair game for a scenario request.

We would need to make sure we document scenario questions formally. For example, once the form is on the website, fill it out. It'll probably have something like: Here's a load forecast we want you to use, and here's the commodity forecast exemption. Essentially saying, “What are the general pieces?” Is it going to be the same as our base case, and you just want an earlier carbon-free date? And there may be other things to tweak.

This way, we've got a record of your request; we know exactly what you're asking, and we can get that moving.

Once the scenario form is up, and some of the other input parameters are set, that will help to inform the way stakeholders want to specify requests for analysis.

We will discuss this in more detail during the scenario meeting.

TECHNICAL SESSION #2: June 22, 2022

The Public: Geothermal Heat

Is there any potential for geothermal or some kind of heat from the ground coming into this mix? Are we looking up to 20 years out?

PNM Response

There is potential for geothermal. We'll look in the deck of candidate resources that we'll be modeling. There has not been that much advancement. The only geothermal operation that we have within our current portfolio has actually had trouble maintaining their output schedule relative to what they would typically forecast.

There are some new advances in geothermal, though. We're keeping an eye on them and discussing the candidate resources on geothermal technologies. It would be great if some of them prove useful because geothermal is more dispatchable than traditional renewables.

Unfortunately, geothermal has not proven to be cost effective or able to be developed in a way that can provide the output relative to what we would need.

Member of the Public: Performance of One-week Models

Can you provide the results of the one-week analysis? Would they be pretty quick to perform on the portfolios that come out of capacity expansion?

Initial Response: PNM

We presented the one-week analysis because the models were set up to analyze those kinds of one week weather events--extreme weather events--and then we layered on additional things beyond just the base extreme weather event. But the models were run for a full year in order to make sure that we're giving the Monte Carlo One forced outages and anything that is based on a full year of sampling. So, we did run them for a full year.

Our thought would be, "Yes, it makes sense to look at maybe two or three selected years for the most cost-effective portfolio, to run them through that same type of stress test framework." We want to get

your thoughts on that. Is it just reporting how those performed or do we want to take the next step of altering the portfolios to try to see what it takes, and then report on the cost that it would take to get it to where the resiliency metrics are the same for the fully decarbonized system as they would have been for the more traditional system? So, there are some additional questions there that we would like to get some feedback on, too.

Member of the Public continued.

Can you evaluate using a storage technology with a low outage rate, for example, pumped hydro, instead of the emerging chemical battery technology, which the report shows to have reliability problems, fires, and over temperature?

PNM continued.

We can put in any type of storage. The idea that we're going to have to figure out is what is the size of the reservoir for that storage.

Whether you're talking about pumped storage, or chemical storage, whatever the total amount of stored energy is, and then the charge and discharge rates, essentially, for the power electronics or for the turbines, if you're talking about pumped hydro, we can model all of that. And one of the input parameters on any of the storage technologies, or any generator, is going to be its forced outage rate. Now, for some of the newer technologies, you've got questions about whether the outage assumptions might be a little bit optimistic, and we know that there have been fires and other things that have occurred with recent battery storage installations where pumped hydro seems to be a bit more available or said to be plagued with some of those problems. And so, we can take a look at that.

One of the key things we wanted to understand is whether you're talking about pumped hydro or battery storage, if you start to have a shift in what your main sources of dispatchable capacity are, and then, depending on something that happens, what happens if you lose that capacity for an extended period of time, especially during one of these cold weather or hot weather events?

There are two pumped hydro projects currently being evaluated in New Mexico, going through the licensing process. Both of them are pretty far away from PNM load centers, and both of them would be rather large projects--600 to 1500 megawatts. So, to tie all of your capacity up in those big resources, in a failure event, even if it's just for a couple of days that occur at the wrong point in time, it can potentially lead to a serious decrease in ability to serve load.

So, we wouldn't want to look at the resiliency standpoint and just say, "Well, what's the forced outage rate?" A lot of it also depends on, "Well, what happens if you have these forced outages, and they occur at the wrong time?" Your outage rate assumes, say, 1% of the year; that's still 87.6 hours. And so, if that 87.6 hours occurs all at one spot at the wrong time, you can really get yourself into some trouble. And so, how do you want to then design the system to make sure that, if that outage occurs at the wrong time, you still have sufficient generating capacity or storage capacity to adequately serve your customers.

TECHNICAL SESSION #3: July 6, 2022

New Mexico State University: Heat Waves

We've heard that the average temperature in New York (or for PJM Interconnection LLC) was going up .7, and we don't really know what the trend is for New Mexico. I'd like to see a scenario that does take into account increased heat waves, the increased occurrence of heat waves in the summer, because that's what's going to stress your system. So, can we look at the trends we know about in New Mexico, project out increases in heat waves, and make a scenario for that?

PNM Response

We understand the question as asking if we could somehow work into the forecast an increase in the frequency and the number of heat waves in a given year. That's something we've talked about a bit internally, including some ways to do it.

The question is more appropriately covered in our reliability, stochastic modeling, and not necessarily something that we would build into a base load forecast. But once we have a properly calibrated load weather relationship model, we could, say, go to 2021, where we saw a couple of heat waves that were pretty geographically widespread, use that as kind of a base weather system, run that through the load weather model, and come up with a load forecast where we are using a period of time as opposed to using normal weather or something to that effect.

So, as we do the 2040 hourly forecasts, we're running a daily weather pattern through and that can be anything that we want it to be right now. It has a typical hottest day in each month, typical second hottest day, and down to the typical coldest day. So, it represents fairly the range of weather that we've seen based on those 20 years of history, and the hottest days. So, we've got 20 hottest days; you average them and that's our hottest day.

(Take the hottest day from each of the 20 years, freeze the 20 years, and average them.)

That's what's driving our peak forecast right now. And the day before and the day before it--those things matter in the modeling. So, the pattern matters as well. We can put whatever pattern we want and see what the implication is.

That is captured more in our stochastic reliability modeling. And in terms of the way you know a couple of increased frequency of events affect the system, even if you're putting in a different pattern, it's still normal weather, and it's still within the same operating temperature ranges.

It probably would not have that big of a difference on the general portfolio, depending on the duration of some of those events. Maybe you start to see a bit of an increase adoption of more firm dispatchable resources or longer duration storage. But overall, the frequency of events is that it's not going to change the capacity builds that much.

And then there are parameters in the model that we can look at and anticipate the impact of an additional degree to the day, the day before, and the day after. If we go through those three parameters, there's some number like 20 megawatts per degree. We'd have to look at the slopes to know what those are.

We welcome specific requests; for example, an ask to look at three extreme weather events per year throughout the period, with an increase of one degree per year. We want specific requests that we can put into a scenario development form to make sure that we're understanding the ask correctly.

We are planning a scenario building session on October 11, 2022, but the schedule may change.

Brubaker & Associates: Import Limit

Are you still planning a technical session for stakeholders in the fall to discuss the import limit?

PNM Response

Yes. We will do a session about the import limit and also one on external modelling.

If there are concerns about the way we're representing the external systems to PNM, they should be raised. By the time we get to October, the ELCC [Effective Load Carrying Capacity] work is going to be complete; the planning, reserve margin, and calibrations are going to be closed. There will still be time to change those a bit but that session in the fall is going to be more about any information that would make us believe that we ought to change the level of imports that we're putting into the model.

If there are things structurally about the model in terms of the representation of the neighbors and other things, we need to be dealing with them now. We can take a closer look, recognizing there may be some interaction with the import limitation, when we're doing the external systems where the import limit was trying to capture some things that were not being modeled as detailed as when some stakeholders are now proposing.

That overlay of the market availability constraint is because you can't perfectly represent everything, and especially those imperfect deficiencies in the market. It's not like you're bidding everything into a common centralized market, and everything's being dispatched centrally.

So, we're trying to better capture those imperfections and then discuss them. Is it going to get us to the point where we're 100% comfortable that we are capturing everything? Probably not, but we think it's going to be an improvement.

Member of the Public: Wind Generation

We can concede a lot about solar. But does wind generation also factor in here? Specifically, how much does weather impact the wind generation capacity for us and where does that come in?

PNM Response

There's not any behind the meter wind generation that we are aware of, or at least not anything readily available to customers in significant quantity to put wind generation behind their meter to use as some type of behind the meter production that offsets consumption at their own meter.

We certainly need to be aware of wind and we'll be modeling wind as a transmission level resource. We are not as familiar with any real way to do distributed wind or behind the meter wind. There's also no specific forecast associated with behind the meter wind additions.

Regarding weather, the impact is big. We can dive into seasonality and other things on wind production a bit more in detail and show some plots. But generally speaking, the heaviest wind production for New Mexico is in the spring, fall, and winter, basically from around Father's Day through the end of the summer when the wind output drastically drops.

Furthermore, there's a much greater wind production overnight and early in the morning; wind production tends to fall off during the middle of the day into the early evening when our consumption is the highest. That comes through in the ELCC [Effective Load Carrying Capacity] analysis when we're looking at developing effective load carrying capability for different resource types. We see that effective load carrying capability for wind relative to when the risk hours are. We see large capacity factors for wind, meaning the ratio of total energy produced throughout the year to its theoretical maximum. We have a pretty high-capacity factor for New Mexico wind relative to a lot of other wind resources across the country.

The major issue is that wind tends to blow when it's not as much needed. You're still left with that gap in the summer, and especially in the early afternoons and evenings in the summer when our demands are the highest. Then, wind is just not contributing as much to meeting those demands, even though it's providing a pretty good energy resource over the course of the year.

Also, other things happen. Typically, with weather, when we get those really, really hot days, accompanied by high pressure heat domes, which typically coincide with very little wind. On those really stressful, high temperature days, you tend to see very, very low wind production.

When you get really, really cold days, there are times when wind resources have to be completely feathered. You're not dispatching if ice builds up on the wind turbines or other things occur that take them outside of their operating conditions. We saw that in Texas a bit during the cold weather event in 2021. And to some extent, we saw some curtailments of wind resources in our system because they got outside of the operating conditions for which they were engineered.

Member of the Public: Fossil Resources

What kind of fossil resources are needed for the transition to a non-carbon state of affairs?

PNM Response

We need to keep all options on the table.

In particular, some of those natural gas resources that are only used in case of emergency, 2-3% of the hours of the year, and renewables are things that enable the transition. As we're moving down this path of decarbonization, we don't need to add combined cycles. At least PNM doesn't need to add a combined cycle or anything that is going to be producing lots of kilowatt hours over the year.

Having those resources that can ramp up quickly and provide energy when needed, under extreme circumstances, and then ramp back down, provides a safety net and a backup to the system as we're going through this transmission transition. These are things we need to keep on the table and in the public eye because people don't really understand them.

Sometimes, there's a misconception about a kilowatt hour versus balancing the system in real time--understanding what the inertia and other system stability requirements are. We will get to where we can do it without fossil fired resources. This is supposed to be a transition. We don't want to take too big of a first step that can end up leading to some type of reliability event that we could have prevented.

Member of the Public: Impact of Sales Dropoff

With the sales drop off, how does that impact on PNM for generation? And what is the impact on PNM's business model?

PNM Response

Generally, there needs to be enough resources under PNM's control to ensure that we can reliably operate the system. With all of that solar coming in, especially behind the meter, we get back the idea of having to have a lot of distributed storage and things that PNM can control in real time to operate the system reliability.

Ultimately, if you're going to have that much behind the meter solar generation, it would seem that you can't have it all with a total aggregate retail rate and net metering credit because there's not going to be enough left on the system. You'd have basically less than half the system paying for all the cost and then having to pay other people for that production when the real value of that energy is not the total retail rate.

Seeing that we have to recognize the ways we have to align the pricing structures in the payments for that distributed energy, what is it really worth to make this all work correctly?

This is a large area that's probably beyond the scope of the IRP per se. There will be grid modernization--the grid of the future. These discussions will happen at the policy level with decision makers. As you move towards this new system, fundamentally, pricing cost allocation, the way the utility interacts with its customers and handles all those distributed resources. needs to be reexamined and viewed in a different light because it's not yesterday's utility system where the utility is generating power.

Centralized plants and sending energy one way down to the transmission distribution network is going to mean a much more communicative grid and a much more bidirectional grid. In order to ensure that you're really comprehending how that's all going to work and how it's got to be paid for requires a reexamination of the way we view the different components and how we price those out.

Member of the Public: Recharging Batteries

How do you factor recharging batteries into this model?

PNM Response

We will dive into this more when we do our modeling.

When you add a battery to the system, when it's charging, it's adding load to the system; when it's discharging, its serving load. We're capturing that dynamic as well the losses that come with everything.

Depending on the chemistry, or the type of energy storage, that loss is greater or less. If you're talking about lithium ion, typically, you've got an 87% round trip efficiency, if you want to fully charge your battery from a full discharge state, Let's just say it's a 100 megawatt 4-hour battery, so 400 megawatt hours. Put in 400 megawatt hours to hold 400 megawatt hours. You've got to put in 400 megawatt hours grossed up by another 15% to cover that loss.

And then once you put in all that energy--and it takes time to put it in because there's a charging rate if you have a 100-megawatt lithium-ion battery--you cannot charge more than 100 megawatts in a given hour. It's going to take over four hours to charge up that battery and that's going to be load on your system when it's charging, in order to be able to discharge for four hours later. You could discharge it over four hours, or over eight hours, but you're limited to that single volume of 400 megawatt hours in this example.

Looking at other chemistries--pumped hydro, for example, is typically 80% round trip efficient. Some of the other things we saw in the RFI from last year were that when you look at compressed air storage or flow batteries, you start getting down into 70%, 60%, and 50%. They all have different charging rates.

So, all of this is built into the modeling in terms of when we're picking the resources that go into the portfolio. The model fully sees and fully takes into account the charging rates, the discharging rates, the amount of energy, the contribution, the competing capacities--all of it. At the point when you're really, really down to that deep decarbonization, the ability to charge your batteries becomes completely limiting, especially when you have renewable droughts or other weather events that don't allow you to simultaneously fully charge your storage devices while meeting your load at the same time.

We are taking into account these different characteristics of the different technology types as we move forward. We've said in a couple of stakeholder meetings now that it's easy to think about storage--short duration and long duration storage are terms tossed around quite a bit--but eventually we need to consider the total volume of energy storage that we need and the charging rate we need to be able to store that volume of energy under certain conditions when we get into the winter with a predominantly a solar system producing much less energy because of shorter daylight hours.

If you need to charge up all of your storage in a shorter amount of time from solar, if it's a shorter daylight hour, you have to have a much higher charging rate than you might need in the summer. There are a lot of dynamics that go into this but each type of storage--batteries, pumped hydro. or other chemistries--has different characteristics. It is a matter of trying to figure out what types you need, where to locate them, and how to maximize that for efficient use of the system.

InterWest Energy Alliance: Getting to Zero Carbon

I understand that the answer to this question may be different in the near term versus the long term because I've heard PNM say many times now that we know where we're going--to a zero-carbon system. How to get there between now and then? Can you address when the need pushes into the late evening, early morning hours? What do you see as the options, resource wise, to fill that gap?

Bottom line: Are you aiming to fill that need, at least in the near term, with a firm resource like gas? Or do you see some kind of battery storage capacity being able to fill that need? (E3 Study Key Finding #4, Slide 32)

PNM Response

The whole purpose of the IRP is to determine the mixture of resources, both near term and long term, which will best fulfill the needs of the system at the lowest reasonable cost while meeting all of our environmental constraints.

Certainly, as we start to shift that peak or that risk out of overnight and into the early hours of the morning, a natural gas resource can meet that requirement. Storage can also meet it, if you have enough--and it's not just enough capacity of storage, but enough stored energy to last you all the way throughout the overnight when you've got to have enough resources on your system to charge while serving your other loads.

Adding enough storage will become a question of economics. When we get to 2040 and have to be 100% carbon free, it will be predominantly storage unless there is some type of hydrogen--new green hydrogen--or non-methane emitting renewable fuel that you can put through existing turbines.

Otherwise, you're going to have a lot more storage--whether it's pumped storage or lithium or flow or any other technology that's out there--but you're going to have to have enough capability of megawatt hours stored, plus some reserves to ensure you can serve those overnight loads. You might need to be able to do it for two or three days in a row.

If you want to be resilient to protect from a renewable drought, then you're going to have to have enough power electronics charging capability to charge quickly enough during periods of overproduction, to charge all of that storage up to have it ready to go, as opposed to flipping on a gas generator.

So, it can be done both ways. We're going to examine both ways. And we're going to report on the pros and cons of both throughout this IRP process.

NMPRC: Bid Information

Will there be a way for developers to know which locations will be the highest adjustments? This seems to indicate transmitted adjustments were made after bids are submitted to PNM. Will developers have access to the information later, that is to say their final project cost as calculated and adjusted by PNM?

PNM Response

If we're doing a full-blown RFP that's one thing. We need to make the distinction that an RFI and the integrated resource planning process are different from an RFP.

If we're conducting an RFP, which would lead to the actual procurement of new resources, when a developer submits a bid, they have to submit as part of that bid what their transmission costs are. That can be done by a transmission analysis performed by them or by some third party. There are a lot of engineering firms that can do that. That information would then be reviewed by PNM. If they don't submit transmission costs, or the transmission costs they submit seem unrealistic, they will be replaced by transmission costs and upgrade costs that are developed by PNM's transmission department for purposes of valuation of that RFP for the RFI.

Your question is if there's enough information in the RFI to have specific locations where we can come up with what that transmission component might be. As these offers are coming through the RFI, they'll be modeled in the IRP; we'll have to make some assumptions about where those resources might be located.

If they're all predominantly storage resources, unless we know for a fact they're going to be up in the Four Corners area, we'll apply some transmission adjustments to those. But they'll all be pretty consistent across the resources because, again, this is a pretty generic analysis.

This is not an RFP evaluation; it's an analysis where we'll be looking for the general trends. And if we start to see from these general trends that a storage technology that has, for example, a week's worth of storage duration seems to be economic--we then might be in the 2028–2033-time frame--we might put that in the action plan, and RFP will then seek to get very specific project information, including transmission costs that we would evaluate before we propose a procurement.

To the extent that developers are going to know what the transmission adjustments in the IRP are-- in the 2020 IRP transmission assumptions were in Section 7, showing the potential candidate resource transmission lines and what those costs were--that information is available, at least looking back at the 2020 IRP.

We can certainly be a bit more specific about it as we're developing the assumptions this time, but the developers have already submitted their responses to our RFI. They can massage those a little bit between now and September. Ultimately, we're going to be taking a look at that information and making our own adjustments to it to make sure that it's representative of what the additional costs would be for transmission.

It's going to be very generic. We don't have interconnection points. We don't have full load flow and other transmission studies that you would do through the RFP process.

TECHNICAL SESSION #4: July 27, 2022

Sandia National Laboratories: Generic Resources

Please give an example of what might be considered generic resource options.

PNM Response

So, what we mean by generic resource options is, there's a difference between generic resources and very specific resources that we would receive in a request for proposals.

So, by generic resources, all we're saying is that whether it's solar or storage, or wind or natural gas, turbines, or whatever other technology you want to think about, any of the resources that we're putting into the IRP, are not going to be specific resources from an RFP that would have, say, a spot in the transmission queue, and have a very specific location where they would be interconnecting, and then have a specific cost associated with that resource that's based on a bid offered into an RFP.

It would be a generic representation of that particular technology type that would have a representative cost to it. It would have an idea of the operating characteristics, but it's just not something that's specifically out there in our transmission queue. It would have an idea of the operating characteristics, generic siting costs, and construction expenses and an expectation of what property taxes, permitting, and interconnection would be.

Form Energy: Temporal Granularity

Can you talk a little bit about the temporal granularity using the capacity expansion component of the modeling**?**

PNM Response

Yes, the temporal component is hourly. Now, the question would be, comparing, when we're doing the capacity expansion piece versus dropping down into a full production cost simulation, what is the number of hours that's represented within the model.

What we've been doing for the capacity expansion is using a representation that is a typical on peak day, and a typical off-peak day for each month of the year--hourly, That presentation of those days and the full chronological constraints would be enforced for U.S. units that have, say, a minimum uptime or minimum downtime, things of that nature.

For longer duration storage projects, we can, based on preliminary modeling, put in net inflow and outflow that would go from month to month or season to season, to try to ensure that we're capturing in the capital optimization, the representation of seasonal storage, and not just the daily or hourly charge and discharge cycles, but also the seasonal aspects of it.

We can also do scenario-based analysis.

So, we want to make sure that we say, “Well, did we quite capture this one correctly?”

If we think about long duration storage, we can say, “Well, let's force in this one resource and allow the rest of the system, say, if we've got long duration storage in there, to add additional renewable resources in order to charge that storage during the shoulder months." So, by forcing in the long duration storage--or requiring that it be part of our optimal solution and then allowing the system during the capacity optimization to optimally build the other resources around that long duration storage--will add more renewables potentially.

And then we'll go into the more detailed production costing. We are going to talk about some things we've been researching and how we're actually changing the way we'll need to look at the production cost simulations, especially in the light of long duration seasonal type storage.

So, the temporal granularity is exactly the same--it's always hourly. The question is, "How many days do you put into the capacity expansion versus doing the full calendar representation when we're doing the more detailed production costing for a given portfolio, and then insert them? It's actually five minutes.

InterWest Energy Alliance: Software for Modeling

Some consumer advocates acknowledge that this is a heavy lift for software programs. And yet, we know that huge computers exist in the world. Could you simply resolve that and do this really complicated multivariable modeling by investing a lot more money in your software? I realize that there are real constraints to the money you want to spend but if you spent more, what could you do? What's really possible out there?

PNM Response

This is not a software issue but a hardware issue. The simple answer would be you could throw more and more and more horsepower at it (the problem), but it doesn't necessarily mean that you're going to get to a better solution all that much quicker. The algorithms that are used underneath of (the current

software(s)) are highly parallelizable; however, if you were to try to put all of this into memory at once, the problem is scale--when you're talking about just a binary integer problem, binary mixed integer problem, the problem size and complexity scales with two to the N, where N is the number of binary variables, if we have 20 years representation in there, and we have even just our system size and say you've got 300 different resource candidates, and some of them are thermal units like on the existing system.

Refer to September 24, 2020, IRP presentation when we were talking about problem size that's got 150 zeros after it in terms of the number of different choices that are out there. And you could parallelize this over hundreds of different computing nodes, but it doesn't necessarily mean you're going to get to the answer quicker or a more optimal solution. As for cloud computing, there's a misconception out there that with cloud computing, that we can just go out there and throw everything into these problems at once, solve it, and get the perfect solution. That's just not the case.

The computing technology that will allow us to make very significant progress to solving these types of problems much, much quicker is quantum computing, where you can represent variables not in a binary state where current digital computing works and you've just got processors that use "bits" that represent all values in terms of ones and zeros, where quantum computing is not limited by binary states and represents values using complex quantum mechanics.

That type of computing infrastructure will allow you to solve these problems much, much quicker. There's just not that much out there, that type of computing. It's still very early in its infancy and being worked on. The computers require significant engineering infrastructure to house the computer to ensure nothing interferes with the quantum states of the processors and commercially available computers as well as the reprograming of software to run on quantum architecture are still nowhere near ready for commercial deployment.

Sandia National Laboratories: Zonal or Copper Sheet Model

Are these results using the zonal model, or are you assuming a copper sheet model? Adding the nodal model and assessing/comparing computational tradeoffs with commitment constraints may be interesting to evaluate.

PNM Response

These results are using a zonal model. We're not using a copper sheet model.

Yes, it'll be interesting to move forward and see what the nodal model does. What we can say is that with the nodal model right now, if we wanted to run a full representation of the entire western interconnect, enforcing full commitment of the resources, just for production costs, it does not include capacity expansion.

A single year run takes a little over 24 hours to solve. So, you could extrapolate on that and say to do 20 years we're going to need more time. And yes, we can parallelize some of that. Maybe year one doesn't clearly need to lead to initial conditions for year two.

But then if you wanted to throw the capacity expansion on top of that, that's a really, really big problem because you'd have to come up with some representation of the transmission system. Then, on the DC load flow side to put into the capacity expansion, force all those constraints, may be something that is just computationally intractable.

We'll be doing some testing on that going forward. It may take a year and a half to develop some simplifications and come up with a more constrained zonal model based on information you glean from the nodal model.

There might be some other things you have to do but, currently, the way things are typically done is you're not doing a nodal capacity expansion merely due to the computational intractability.

Sandia National Laboratories: Energy Efficiency Bundles

Based on Slide 15, it seems pretty safe to assume that those lower cost energy efficiency bundles are going to be selected by the capacity expansion plan. So, I don't see the harm in free solving the model and saying, if the energy efficiency bundle costs less than $35, less than $25 a megawatt hour, just force it in and don't spend the computational power to figure out what should be obvious.

PNM Response

That's certainly another approach, We could force everything that's $35 or less, or $50 and less**,** and still have the $50 bundle as a choice variable. Or, instead of just doing $50, do 50, to 60, to 70, to 100 and divvy that up.

But the one thing we see here (Slide 14) is, as we go out in time, the very small tranches were actually the highest cost tranches. So, we need to make a note to go back and double check and make sure that the color scale on this slide is correct.

But, as we're moving up in time, generally what we saw is the amount of available energy got smaller.

CSOL Power: Thermal Storage

What is it going to take for you to include thermal storage?

PNM Response

We are not taking any options off the table.

We did have some thermal storage offered in an RFI last year. The concepts were not fully developed enough for modeling, unfortunately. We're still going through the RFI this time. If there's enough detailed information for us to put that into our Integrated Resource Plan, we certainly will.

We are not discounting or precluding any types of storage. Using existing or new technologies, we have to make sure we have enough detailed information to model accurately, or as best as possible.

CSOL Power: Renewable Energy Drought

When you assume the renewable energy drought, did you assume less need?

PNM Response

The answer to that is no. We were taking the renewable production that was typically used in our, reducing the renewable production, but keeping the load at the same level as before.

That might not be a 100% correct assumption, but part of it is due to the expected proliferation of behind the meter generation such that when we have a reduction, say, in solar, we're going to see higher loads due to the reduction in the behind the meter solar that's reducing what's seen at the meter typically.

InterWest Energy Alliance: Pumped Storage

How feasible is pumped storage in the desert Southwest and New Mexico? How much water is consumed through evaporation? What are the assumptions about water availability during summer peaks? With monsoon failure?

Initial Response: PNM

So, there are two projects that we're aware of that were offered into the RFI last time. The information associated with evaporative losses was presented in the disclosure of the RFI and the public advisory process last year. There is a pretty reasonable amount of evaporative losses.

There are two projects that are currently going through the Berg licensure process that we're aware of in the desert Southwest here, in terms of the water availability during summer peaks. That really gets down to your question about the evaporative losses. It would be a one-time fill of how many acre feet. We can go back and check the presentation from around January 2020.

So, once you've got the water filled in the water rights, I believe one or both of these projects might have been on tribal lands, and the water would be coming through the water rights and supportive of coming from those tribes that would be in support of these projects. And then there would be evaporative losses, but beyond the evaporative losses, it's more of a closed loop system. It's not within the river networks.

With monsoon failure, again, these are one time fill and then you've got the evaporative losses to account for each year.

We will be having a presentation in the future on the RFI responses for this year.

The pumped hydro assumptions were covered in the 2020 presentation and the 2020 IRP. There was information as well within the IRP write up, We need to go back and double check if the evaporative losses were fully documented in the IRP.

PNM Update

The evaporation rate and pumped hydro assumptions for RFI response in the 2020 IRP were not disclosed. PNM has researched the evaporation rates associated with pumped hydro systems and can provide the following information:

Pumped hydro systems can be open or closed loop: An open loop system is connected to a flowing water feature (like a river), while a closed loop system is not (the same body of water is moved back and forth between reservoirs). Evaporative losses from the reservoirs will depend on a multitude of factors, including the climate and area in which a project is sited, the size of the reservoirs, and whether or not those reservoirs are covered. Coverage of one or both reservoirs can substantially reduce evaporation.

PNM issued an RFI for Resources Available for Future Generation in March 2022 and received two responses from pumped hydro storage developers. Both responses described a closed loop system with an initial reservoir fill of approximately 5,000-acre feet, with expected refill due to evaporation of about 500-acre feet per year (~10% of initial fill) if both reservoirs were left uncovered. However, both proposed projects included a plan for coverage of at least one reservoir to control evaporation. Other water discharge was estimated to be negligible.

NM RETA: ETA Ramp

What is the renewable contribution to total generation assumed in 2035? When this scenario is run, where are you at in your ETA ramp?

PNM Response

The ETA between 2030 and 2039 requires us to have 50% of our retail sales coming from RPS [Renewable Portfolio Standard] eligible resources. From 2032 to 2039 there are also requirements that we are serving our system with an average carbon intensity of 200 pounds per megawatt hour or less. So, those two items would be reflected in these simulations.

This is not something that we need to dive into in too much detail at this point--or what the total amount of renewables are. This is more a proof of concept on improving the long duration storage modeling.

The best answer to some of these questions can be found by reviewing the scenarios in Appendix J in the 2020 IRP, where you could get an answer, based on the scenario and sensitivity, regarding what the total amount of renewables on the system were versus other resources.

New Mexico State University: Parameters of PHS Analysis

Could you be specific about what parameters from this PHS (pumped hydro storage) analysis would feed back into Encompass capacity expansion models?

PNM Response

What we're talking about is one of the parameters within Encompass called net inflow and net outflow in the capacity expansion model.

When we're looking at the amount of energy in excess of what was dispelled from the reservoir in a given month, what are we expecting the net increase in the reservoir level to be from month to month, or the net decrease in the reservoir from month to month, would be an input for the capacity expansion model to make sure that there was a representation.

The capacity expansion is looking at a representative on peak day and off-peak day for each month. And then, based on the number of days in each month, it is scaling up the operational characteristics from that representative on peak and off-peak day to come up with a representation of what the total costs and total operating parameters were, based on that simplifying assumption, even though it is doing an hourly piece and ensuring that the chronology is maintained.

Now, one of the ways that Encompass maintains the chronology for resources within the capacity expansion model is that it will say that the last hour of a month must be equal to the first hour of a month. And that gives it a kind of cyclical chronology. And you're not saying. "Okay, well, I could go from, say, August 17 to September 11 and then back to August." Rather, you're always doing a loop back of, say, August before moving to September.

Because of that, you have to give it an idea, then, of what you would expect--the net position relative to that starting and ending monthly or that it would be increasing or decreasing to allow for these seasonal shifts, or month to month shifts of energy.

So, we can run a simulation that gives us an idea of a full year memory--the entire problem is going into computer memory at once, giving it perfect foresight of all of the conditions as it's solving that problem simultaneously for each of the variables.

We take that information and then feedback from it to better represent the resource and the capacity expansion. That will then allow the model to give a better idea of which additional, renewable, or other resources are needed or not needed, given the longer-term storage resource.

NM RETA: Cost of Storage Technologies

Are the capital costs of the specific storage technologies a viable parameter in the modeling? Or is the storage cost model a generic unit cost?

PNM Response

The cost by technology may vary dramatically.

There will be a cost tied to each technology type when we're looking at generic resources. So, there would be a capital cost variable operating cost, fixed operations, maintenance cost, and safer pumped storage--which would differ from lithium-ion storage, which would differ from combustion turbines, which would differ from any number of other things.

Each individual generic technology type is represented with its own individual cost, operating parameters, and efficiency cycles.

Sandia National Laboratories: Minimum Duration for LDES

What is the minimum duration requirement that was built into the assumptions for LDES [Long Duration Energy Storage] technologies?

PNM Response

There is no minimum duration requirement per se. We are doing this as a proof of concept. This particular proof of concept is looking at a rather large, but known, potential pumped storage hydro project that was a 1500 megawatt under 1000 gigawatt hours, so maybe almost 70 hours of duration.

There are other technologies out there that we're aware of that are 100, 150, or more hours of duration--lithium, you can just stack more cells on--and so, we're not looking at this and saying there's a minimum duration requirement to qualify as long duration storage. What we are looking at is: What are the different technologies out there, and how do they, given their efficiencies and other things, start working within the context of our system?

We've said this in different stakeholder meetings, and we think that really what we need to do at some point is disaggregate the idea of duration. You need to have an idea of what the total volume of energy storage and megawatt hours are going to be on your system. Then, you should have an idea of the most constrained periods, which are going to be--if you're looking at charging from solar--mostly in the winter, when you've got the shortest daylight hours.

And what is the charging rate? If we will need to fill storage, we need to have that volume of storage necessary to meet hourly, daily, weekly, and seasonal demands going forward. So, there's no prescriptive duration per se that denotes long duration versus short duration versus medium duration.

We're going to need all of those on our system and we're looking at the modeling techniques that will best allow us to compare the tradeoffs of costs and benefits associated with those different technologies.

Member of the Public: Evaporation Reduction

Following up on the question about water availability, broadly, how much activity is being seen on promoting evaporation reductions of systems that have been used in other parts of the world, such as the ancient canal system from the Middle East, and also in Peru, where aqua like structures run underground? This is just clearly an issue beyond the IRP, but I'm putting it on the record here.

PNM Response

We're going to be focusing on the water associated with the pumped hydro, as well as the utilization of water by the other parts of the system within other generation technologies. We agree that if we want to have a fully sustainable society, we're going to have to start looking at closed loop systems, including underground systems for water delivery.

That doesn't necessarily mean we're going to limit everything. Trying to fix leaking underground pipes when they're buried is pretty difficult. So, there's a lot of work that needs to be done overall to move to a truly sustainable society. Right now, we're obviously focusing on the electric system here in New Mexico.

CSOL Power: Hydrogen Generation

Considering that to even consider hydrogen--the power generation industry is energy intensive--is dangerous and takes away from an easily decarbonized electric grid. How do you justify this analysis?

PNM Response

We are considering all options at this point. The industry is looking at hydrogen, considering the modeling techniques to make sure that we are looking at this in the most rigorous way. Most utilities out there, if we look at them, are keeping hydrogen on the table as a mechanism for energy storage and it could be part of a decarbonized system.

We believe we are in line with the industry view that this should be considered as part of an IRP analysis.

Sandia National Laboratories: Payback and Generation Plots

Looking at the payback and generation plots (Slide 28), I was just curious about the terminology payback first generation. It sounds like difficult math: If you're getting more than you're putting in.

PNM Response

The payback is the term that's being used for the amount of energy being put into the system to be converted and stored.

So, the round trip on the hydrogen that we've got here is roughly 28% round trip efficiency. We've got to put in, say, three and a half megawatts from the grid to get one megawatt back to the grid, after being converted, the hydrogen, stored, and then put back through a turbine.

The turbines were roughly 10,000 to 10,500 heat rates, so the turbine itself was about 500, or 33% efficient. Hydrogen has about 1/3 the heat content of gas, and there's the power needed to run the electrolyzer [hydrogen generator]. So, this system here is about a 28% round trip efficiency.

If you compare that to pumped hydro or lithium, those are in the 80, 85, 87% range. And then other storage technologies fall in between.

The 28% may be a bit rosy. We're trying to use some data from manufacturers that are working on developing and selling each of these components; we're relying on some of that data. We don't have an actual hydrogen system on our system, or hydrogen production system on our system that we can actually pull live data from.

The payback is charging energy that includes all of those pieces, to get to the point where it can, then, come back to the grid.

InterWest Energy Alliance: Import Assumptions

What did the results look like with higher medium import assumptions rather than low import assumptions (Slide 30)?

PNM Response

Those results are in the 2020 IRP at the end of Appendix M.

The other things we have been talking about are those import assumptions, especially out into the 2035–2040-time frame. We do not expect that there's going to be near the surplus of energy in the market, especially during non-solar producing hours.

If we consider the transformations of most of the systems in the West, you're building in assumptions that we can rely on our neighbors to charge our storage devices, or that they would potentially sell us energy out of their storage devices to help us meet our net peak loads. We think this would be an incorrect assumption, until we can move forward in time and see what's really going on.

As a utility, we know that if we only have four hours' worth of storage, and we're not sure whether we're going to need it in a few hours, we're not going to sell that to somebody. Right now, and going forward, the predominant source of energy, as we saw from the regional resource adequacy study performed by E3, is going to be solar and storage additions.

So, the idea that we're going to have a lot of available imports to charge our storage devices, especially during off peak, is just something we don't think we can support.

CSOL Power: Percentage of Hydrogen to Natural Gas

What is the proposed percentage of hydrogen to natural gas for the combustion turbines?

PNM Response

We're showing a proof of concept on the 100% hydrogen utilization in a year far down the road, towards the end of 2030. These are once we get to a carbon free system.

Blending presents its own unique characteristics: There is work to be done in terms of modification of plant equipment, pipelines--all the things that would need to be accommodated for hydrogen blending. Also, volumetrically, hydrogen contains 1/3 of the heat content of natural gas. So, even if you were to do a 50/50 blend, volumetric-wise that doesn't represent a reduction of carbon by 50%.

So, in light of pathways to 100% carbon free, blending doesn't really get you there. Blending might reduce a little bit of carbon, but you'd have to volumetrically add in 80 or 90%-- volumetrically blend 80 to 90%, hydrogen relative to 10 or 20% gas just to do 50% reduction in the carbon emissions from that type of setup.

From the modeling we've done, all of the graphs are from 100% hydrogen.

CSOL Power: Technology Readiness Burning Hydrogen

What's the readiness technology level for burning hydrogen?

PNM Response

There are facilities in operation today that can do this. PNM does not have any on its system currently, but there are certainly turbines out there that can burn 100% hydrogen. There are some that will need additional work to get them up to burning 100% hydrogen, depending on which turbine technology and company you are looking at. There is certainly already the ability to electrolyze water into hydrogen and store it.

So, the technologies exist. It's really a matter of which turbine you want to use, what the costs are, and where we see those going.

Brubaker & Associates on behalf of NM Area: Energy Efficiency Bundles

For the most expensive energy efficiency bundle, maybe it would make sense to model that and multiple bundles if the EE products are different**.**

PNM Response

For some additional information on the EE (energy efficiency) bundles and how they're developed, AEG will return to discuss that when their study is complete. But you can see some of the information in the August 25 presentation in the 2020 IRP.

Each bundle comprised a number of different measures. For each year, the characteristics of each measure are used to determine what the weighted average life and weighted average price of that bundle is. Certainly, one of the ideas that we've mentioned earlier was that perhaps it makes more sense to break apart that $50 bundle and do a few different price tranches—50 to 60, 60 to 80, and so on—and then, for each deal, determining which price points you wish to measure and what the overall shape of each bundle would be, given the measures that are in that bundle and those price points.

We can consider all of these ideas with AEG and provide them direction on the ways we want to do the different tranches of the bundles.

NMPRC: Source of Hydrogen for RPS

Can PNM like to comment on whether the source of hydrogen matters for meeting RPS [Renewable Portfolio Standard] requirements--whether the current RPS requirements or lifecycle are purely at the point of degeneration, or how and if that is a part of the overall IRP analysis, especially in the longer timeframe?

PNM Response

Hydrogen is not a renewable energy resource under the Renewable Energy Act, so hydrogen in and of itself, whether it was produced by renewables or produced through some other process like steam methane reformation, would not count towards meeting the RPS.

Any hydrogen production of generation would have to be a part of the 20%. If we're looking at 2040 and beyond, it would have part of the 20% of generation that could be attributable non carbon emitting resources, but not necessarily renewable resources. Depending on the resources that are used to produce hydrogen, whether they are renewable resources, or whether you do it through steam, methane reclamation, or some other process, additional renewable resources on the system could count towards the RPS and increase the percentage of RPS that we're meeting.

That being said, the Energy Transition Act requirements relate to retail sales. And it's not necessarily that the loads from electrolyzers would necessarily be retail sales. That could be considered station service or other things.

So, there are a lot of little nuances that would go into this issue and how the regulator's would view each of those pieces. But the RPS is a percentage of retail sales. And it is related, not to life cycle, but specifically to the amount of energy we are required to deliver to the retail end use customers.

Whether additional regulations or laws come through in the future that talk about full supply chain emissions and other things remains to be seen. In the Integrated Resource Plan requirements, we have to meet our renewable portfolio standards that are relative to generation production by renewable eligible resources under the Renewable Energy Act, and that ratio of the production to retail sales--whether it's 20%, 40%, 50%, or 80%, corresponding steps from 2020, 2025, 2030, and 2040.

Grid Strategies on behalf of InterWest Energy Alliance: Generator Minimums

Does ignoring generator minimums by using partial instead of full commitment for the capacity expansion miss some of the value storage provides by charging during periods when generators are at a minimum?

Initial Response: PNM

If we go back up and look at these plots (Slide 13), what we actually see is that there's greater storage utilization in the partial than in the full commitment. We attributed that to the fact that, in this situation, you could commit at lower than the actual minimum load.

So, when we think about this, there's a binary variable that represents whether or not a unit is committed. Under the full commitment, that binary variable in a given hour would represent a zero or a one but in a partial commitment, It could represent, say, a point for the 40%. That 40% would then be applied to the minimum loading of, say a CT [Current Transformer], if it's minimum loading, say it's 100 megawatt CT, and its minimum loading is typically 40 megawatts.

Now, rather than doing that, if you do the partial commitment, it's 40% of 40, or 16 megawatts. So, then we can have our thermal unit committed at a lower level, which allows for greater storage utilization. If we still need to commit that thermal unit under full commitment, but it's committed at a higher minimum load because the percentage is no longer applied--it's either a zero or a one--you actually end up seeing a little bit lower utilization of storage.

PNM continued.

We've done some testing on the capacity expansion and partial commitment. And for the most part, we're seeing the same resources, the same expansion plan, and in both scenarios, we're seeing the same resources being added on both sides.

So, from at least the capacity expansion side, we don't think we're missing, anything,

InterWest Energy Alliance continued.

I can see how it can go both ways. It does look like in that slide that it reaches a little bit lower dispatch in the earlier years in the partial commitment, but then it does do better in the last year.

We're basically going to be curtailing renewables because you've got your pure thermal generation running at its minimum. And the storage can provide value by charging and absorbing what would have been renewable curtailment, if the minimums are lower, removed entirely, then that benefit is less appreciated.

But we can see also how that can be offset by what you were talking about, that effectively, the partials give you lower minimums on the thermals.

PNM continued.

The thing to take away is that, in our testing, whether we're running a partial or full commitment on the capacity expansion itself, it is just computationally intractable. But that is not the case when we do some limited tests. And were we to do, say, a full commitment on a shorter time period, or reducing the system builds, it ends up being the same whether we're doing partial or no or full commitment.

That gets into the same idea we had here (Slide 12): having a three-step process where we're starting with a simplified solution.

When we have our more simplified representation and settings, and when we have to put more and more years of data and choices into the model, then, as we move forward and move down, we've got the expansion locked. But we need to make sure we're getting the right representation of long duration storage. Then, we can move down further and do a full commitment.

So, by the time we get to the end, and the overall system metrics that we're reporting, we've gone through various levels of details and got down to a full commitment.

We are getting pretty comfortable with the way this is working. There's no computationally perfect solution at this point. But all the tests that we're doing right now at least are showing that this process is working very well. And by the time we get to the end, we do have the full representation of all the commitment decision variables when we're running the production costs**.**

Sandia National Laboratories: H2O Recovery

Is anyone recovering the H2O after hydrogen combustion at utility scales?

Initial Response: PNM

That's something we can definitely look into and see if we can find any information. There are some closed loop test systems out there. If anybody's doing that at utility scale up, it's just in test systems at this point.

PNM Update

We haven't been able to find specific discussion regarding projects that implement a water recovery system after hydrogen combustion. We expect as time progresses, more information will become available.

For more information concerning current pilot projects, Clean Energy Group produces a list of hydrogen pilot projects across the US which can be found using this link: https://www.cleanegroup.org/ceg-projects/hydrogen/projects-in-the-us/

NMPRC: Battery Storage

Slide 31 shows that if you had, say, a 100 megawatt 4-hour battery storage system, you could dispatch it for 50 megawatts for 8 hours. Would that have any effect on the life of the batteries themselves, or are there any concerns along those lines?

PNM Response

Discharging at a lower rate would not have much effect on the batteries. Typically, the factors, at least with lithium, that most affect the overall life of the batteries are if you go through deep discharges, multiple cycles per day, actually keeping energy stored in for too long.

A lot of the vendors are telling us that over the course of a year you want to have a 40 to 50% average state of charge. So, discharging it over a longer window would actually reduce the number of cycles you would have in a given day or over a given year. It may actually limit the degradation as opposed to add to it.

NM RETA: Impact of SCOTUS Decision re EPA

Has the recent decision in the Supreme Court of the United States regarding EPA air quality program and implementation affecting requirements for PNM CO2, as used for IRP purposes?

PNM Response

We're still looking through that, but I believe the answer is no. The requirements under the [state] Energy Transition Act appear to be more binding. So, we can follow up with you on that. But right now, we don't see the need to change the way we're doing carbon emission modeling related to that decision with the New Mexico Energy Transition Act, NMSA 1978, Sections 62-18-1 to -23, requirements are still going to be the binding requirements.

Public Advisory Group Day: August 17, 2022

InterWest Energy Alliance: Regional Sharing

Understanding that we can't necessarily rely on [regional sources] 100%, it raises the question: What is the reasonable degree to what to which we can, If not rely on that, then use that as a possible or likely source? And how do you measure that?

I agree an RTO [Regional Transmission Organization] would help that, But until you look at it for PNM, from PNM's perspective, you're not going to know the answer, you're not going to be able to even put some color around how you might address that.

So, I guess what I'm seeking is not just a kind of dead end closed door, but what can you do to more fully elaborate or understand the opportunity and its likelihood and its cost? Those are all things we need to take into account.

Initial Response: PNM

You're right. Due to the fact that there were disruptions and defaulting and delaying renewable and energy storage contracts that were supposed to be coming on, we have had to take some short-term

actions. Some of those short-term actions have resulted in some contracts with hydro flows that would come down through CAISO and over to PNM. That is not always going to be there. Those were very short-term deals. Absent having a full RTO that has a centralized dispatch and [can] ensure that we can count on some of those resources, I wouldn't want to incorporate that into my long-term planning process.

I want to make sure that I have the necessary resources under my control long term to serve my retail customers. And that's a key distinction. By rule, the IRP focuses on the least cost way to serve retail customers only. There are other loads, other resources, in the BA [Balancing Authority], and then there are things that happen outside the BA that can be taken into account in a broader perspective. But in terms of what has to be done for the IRP, that is retail only.

I want to make sure that I've got the resources under control. Now, what can we do more broadly with PNM and taking a look at some of these things? We do have participation in two different market working groups: one that's looking at the enhanced day ahead market through CAISO, and another that's looking at potentially a western SPP [Southwest Power Pool] market. We've got members here at PNM looking at those. I'm actually participating in a western market exploratory group and helping to look at the resource adequacy design of any market that may come to fruition.

But likely, even if you had 100% go today by some of the larger entities in the West, you're probably not going to have a full-blown RTO that's operational until 2030, or past that. And then to think about from then, if they start doing regional transmission planning, how to use how quickly is that planning gets done, how quickly do the lines get filled? That's even more time. And we've got to decarbonize by 2040 by our own commitments and no later than 2045.

So, the idea that an RTO or that transmission can be the silver bullet, I'm just skeptical of that. We're going to have to look at a lot of other solutions.

Just as an example right now, if we wanted to increase some of the power-flow capability just within the PNM system, say, coming down from the San Juan Four Corners area into Albuquerque--the northern line is one of the lines that we've looked at before. We see that coming up again and again in certain transmission related studies, and that was talked about in our last IRP as well. But you're looking at a long, long lead time, predominantly because of the permitting, right away, and other things to get that going.

So, if you're thinking that we could get transmission built very, very quickly, that's just not the practical case, unfortunately. I would love to have more transmission.

But we are thinking about some of these lines and the number of entities that can weigh in on whether we should move forward on these, both the state and the FERC process. You've got state land, federal land, tribal, and all of those things. It's likely that a line could take 10 plus years for us to get done, and that's if it were to get moving today and it doesn't get disrupted.

So, we're fully supportive of the idea of expanding the transmission network; we're fully supportive and exploring those ideas around regional participation and transmission organizations. But it's not something that can happen overnight, and there just has to be realistic expectations on how and when those might come to fruition, and then how those can flow through into the broader planning process. And none of that alleviates our needs and our requirements to decarbonize quickly over the next 18 years.

InterWest Energy Alliance continued.

Thank you, That's helpful. But one thought I'd leave you with is--I don't want to batter this--but the longer you delay, the later you're going to get it. So, I understand you're really focused on the next 10 to 20 years, but the IRP is supposed to be longer term as well. So, just leaving you with a thought that if this is not a priority to start working on, or really thinking about planning for now, the later you're going to get it. So, if it's an important element for you, and I think it should be, it deserves some attention now.

1:37:28

PNM continued.

And again, we've got folks here in the company working on that.

Specifically. The IRP has to look at a 20-year planning cycle, and it's for retail only. So, I appreciate your perspective.

Transmission is on the radar here at PNM and, again, we've got a lot of work going into that from different parts of the organization, myself included. In terms of how that type of RTO and transmission analysis can work into the retail planning process is different from a broader BA planning process, is different from a western interconnection type of a framework.

So, there are lots of different things we're looking at. And just because I'm saying here that there's going to be some timeframes involved that may preclude the early onset, that doesn't mean we aren't putting the efforts into it here; we're fully supportive of those things.

Transmission itself does take time and trying to get an organization built up that could then do transmission and the advent of a full-blown RTO, PNM is not the only entity that can drive that. Your work through a number of different states and with your organization and pushing some of the larger utilities is going to be one of the most important things that can happen to try to get a western RTO off the ground.

Talking with the other folks out there--like NV Energy, PacificCorp, and APS [Arizona Public Service] and SRP [Salt River Project]--it's some of those really large utilities compared to PNM that are going to be the key members that have to come across in order to get a full-blown RTO going.

Grid Strategies LLC continued.

I did have a quick point. I wanted to build on the session [InterWest Energy Alliance] brought up.

I think transmission really is a big part of the solution here--and obviously your full RTO or resource adequacy construct will help but the physical reality is that transmission alone will give you a lot of benefit for geographic diversity that addresses a lot of the risks you see in a range of severe weather events.

Going back to the ERCOT [Electric Reliability Council of Texas] example, I pointed out earlier that I think a big part of the reason why you see these issues with ERCOT and not parts of the eastern western interconnect is that ERCOT is basically an island with a gigawatt tied to its neighbors.

Whereas I feel like the experience of MISO [Midcontinent Independent System Operator?], for example, during winter storm Uri, they were importing 13 gigawatts, from their neighbors, from PJM, from the southeast, from Canada. ERCOT was bringing about 800 megawatts, so 15 times more into MISO, and with that diversity you'll be able to access--it is diversity in a few different things, it's diversity and load.

So, obviously, any severe weather event is not going to be that large, but they're not going to be equally severe across a huge footprint. That's just the nature of weather: It's not going to be the same everywhere. And so, you get a lot of diversity, even going one or two states over. Yes, it may be hot, there may be cold there, but it's not going to be as extreme as where you are.

So, on the load side, there's benefit.

For the same reasons, there are benefits on the conventional generator outage side. Again, the generators really only see these issues when you get to these extreme events. And if it's a little less extreme in Arizona, or California, or wherever, you're getting a lot of value out of that. They're less likely to have the same level outages that you are.

And then renewables, obviously, are, very critically on the wind side, very much driven by this. There are very large differences in wind patterns from one state to the next, even 100 miles away. Solar is a little more correlated, but you do have some monsoon events and other things like that [when] there is a pretty strong diversity benefit in solar.

And so, my point is, I think transmission gives you that benefit, with or without the RA construct, because, if there are supplies elsewhere--other regions in the Southwest are less affected by whatever severe [conditions than you are]--they're going to have less high demand or more supply. And you can likely have transmission ties will make it more likely that you can import that and meet your load with that.

Statistically, the correlation on all these factors is going to be less than perfect. And so, if you get a little bit of benefit. For example, the 2020 west heatwave was a pretty dramatic, unusual event in terms of geographic breadth. I've looked at that, and there was still 10% diversity.

Across the north--I've looked at the Northwest I haven't looked at the Southwest--across the Northwest, including California, during that event there was a 10% diversity and load, when you bring in renewables, that adds a few more percentage points to that. And that's really tremendously valuable. And yes, you can better realize that value, if you have a resource adequacy construct, or full RTO that basically allows you to reduce your planning reserve margin and your actual capacity expenditure.

But reality is this is a physical phenomenon. And If the transmission is there, you can capture a lot of that benefit. Not all of it without the RTO. But a lot of it.

I really would encourage looking increasingly in this direction, and particularly with decarbonization goals, transmission is absolutely essential because of that geographic diversity of the wind and solar.

I think it'll be extremely costly to try to meet these very aggressive decarbonization goals without seriously looking at major increases in transfer capacity between your different parts of the region, and then even potentially, between [WAC?] and the Western Interconnect and [NERCOT?] in the east.

Anyway, that's getting a little farther afield. But I think transmission is important.

I will note also, there's a lot going on at FERC related to this. There's the transmission planning and cost allocation--comments are going in today. And then next week, nine days from now, there's--most relevant to this--a proposed rulemaking on accounting for severe weather in the NERC TPL 001 standard, and potentially pretty much exactly what we're talking about right now: this issue of accounting for severe weather when you're doing transmission planning and contingency analysis, and building the transmission system, having enough transport capacity to protect you against events like this.

Yes, it's an ongoing issue. And yes, certainly you're right. This transmission takes a long time to build. Nobody's going to dispute that. But I totally agree with [InterWest energy Alliance] that that's all the more reason to get moving, now. We need these transmission lines in the very near future, particularly given New Mexico's decarbonization goals.

So, I think there are a lot of reasons to be moving quickly now to start the process and get the ball rolling, because we're going to need that.

Member of the Public: Heavy Power Users Near Wind Farms

What if any activity are you seeing of heavy power users locating near wind farms and low population areas to take advantage?

Response: PNM

Here in New Mexico, we're not seeing large power users necessarily putting facilities located next to wind farms. In fact, we actually see so much wind relative to the load in the eastern part of the state causing disturbances on the transmission system that are going to have to be addressed going forward.

So, for us specifically, we're not seeing too much of that.

Prior to coming to PNM, in some of the work that I did before I came here, there were a lot of large, heavy industry users who might site near heavy places where there's a lot of wind production, and low locational marginal prices that they could get on a real time pricing tariff so that they can reduce costs for their data centers or other type of large, heavy and mainly data centers. Probably nowadays it's the Bitcoin miners.

We are seeing a lot of requests in the Texas service territory from PNM's sister company TNMP in terms of increases in bit mining and data center loads. I'm not sure that those are being sited near wind farms or anything specifically. There were a lot of folks who, back in the mid 2015 timeframe, were looking to site data centers and other heavy industry energy users near wind farms to try to take advantage of the depressed locational marginal prices [LMP] that were caused by large injections of wind energy.

So, those wind energy developers would offer their wind energy into markets at negative $25/30, negative $30 prices because they could still make money given the production tax credits that were authorized through the federal government. And that would cause localized depressions of energy prices, and if users could site right near that, in order to get on a real time pricing tariff--unfortunately, New Mexico doesn't have a real time pricing tariff.

But if it's, say, in Iowa or other places, they could get on those tariffs. They could then sometimes even get paid to take power because locational marginal prices would be negative. And that would be a business decision for them to site their data centers or other things close to wind energy production facilities.

New Mexico State University: Increased Storage Assets

Is the increased cost associated with adding storage assets to cover more tail events in a report you have published?

Initial Response: PNM

We talked about [this at] our May 24 [2022] and June 5 [2022] meetings: some resiliency work that we've done in combination with Astrape and E3. And that's what I've been referencing a little bit on the increased storage assets.

We didn't do an economic analysis as a part of that report; we just looked at the amount of increased megawatt hours or storage duration that would have to be added in order to kind of normalize for expected unserved energy events.

I think that what you could do pretty easily is go to some pretty generic public data, or we can try to get some for you. I think NREL in their ATB, their Annual Technology Baseline, break out, for example, on lithium batteries, the power component versus the energy component.

I think in 2025, the expectation is a little bit under $300 per kilowatt. and $300 per kilowatt hour on those pieces. And so, if you're talking about [how] we need to move from two- and four-hour storage to 14 hour and 16-hour storage, you're talking about adding 14 hours per kilowatt of duration. And so, at $300 per kilowatt hour, that math is pretty substantial if you're just increasing that component relative to, say, a firm dispatchable natural gas generation resource.

E3 continued.

I've definitely appreciated listening to this whole discussion. And I think a lot of the points that [the presenter] made in his presentation I think are well taken here and definitely prudent for PNM to be considering. I think a lot of this discussion cuts to the heart of basically the challenge that the industry is grappling with right now, which is how exactly to build in extreme weather fuel supply related events into reliability planning.

I think there's, from my perspective, maybe two kinds of challenges.

One is that it's certainly useful to kind of look around the country and recognize the challenges that others have seen and kind of actually observed in operations. But, at the same time, a lot of the risks that exist here are so highly system specific and dependent upon the exact nature of your system, that this is a challenge that's really difficult to generalize from one system to another, unlike some of the other more traditional reliability challenges. So that's maybe one comment on that.

And the other is one that's already been recognized, I think, by a lot of the presenters or comments today, which is just the nature that these events are so difficult to characterize in terms of their probability, that even though a lot of areas are looking into what would be the outcome if we were to experience an event like this. I haven't actually seen anybody who's been able to kind of build the sort of fuel supply related issue directly, and in a rigorous way, into a probabilistic framework for resource adequacy, like is implied by the one day in 10-year sort of study.

So that's not to say there is no worthy sort of effort here or goal of trying to bring this more fully into the resource planning paradigm. But I do think it is kind of a challenge that a lot of the industry is grappling with, and that I haven't seen a really elegant or robust solution to, in any of the places that we've done work.

PNM continued.

I want to comment on this a little bit as well.

In terms of the way the neighboring systems to us are today versus the trajectory that the entire West is on in terms of decarbonization, the idea that, we can purchase power in the winter to help offset some of this fuel supply risk is mitigated currently, because of the surplus capacity in the non-summer months by some of our neighbors, and we're not in in terms of the way we're looking at our reliability modeling, limiting any type of imports or other market assistance in those winter months because we just don't see that in our data as well.

But as we move forward and we're recognizing we're modifying some of the neighbor modeling going forward--as RPS requirements increase and what in particular the work with E3's resource adequacy assessment for the desert southwest showed--a lot of the IRPs by our neighbors and those folks in Arizona and others--by the time we get to 2030/2033 when more traditional generators are retired and a lot of replacements tend to look at predominantly gas, solar, a lot of solar, and a lot of storage, there may not be that ability to purchase power to mitigate some efforts in winter. That could increase winter LOLE risk not just for PNM, but more broadly around the West.

We take everybody's comments to heart. This is an issue that we're going to have to be keeping focused on, figuring out the best way to include this in our planning, and making changes to our system going forward.

And it's really from what we're seeing right now more likely a phenomenon that we need to be ready for and addressing specifically come the 2030 to 2035 time-frame when a lot of the neighboring entities really have their hard upticks in renewable and energy storage requirements.

E3 continued.

I'll actually note that several years ago, I think it was back in 2018 or so, WECC commissioned a study looking at gas electric vulnerabilities in the West. That was a study that we were involved in. [But it was led by Wood Mackenzie and Argonne National Laboratory, who are the owners and run the [NP fast model?] that [the presenter] alluded to in his presentation. We're also involved in that.

[The presenter has] highlighted the vulnerability that I think those folks in working with NERC had previously identified in Arizona. And the west study certainly looked at that as well: Basically, what are the implications of region wide fuel disruptions in the southwest region on the ability of the region as a whole to maintain reliability. And I think it was pretty interesting. And maybe we can point folks to that work after this workshop.

But one of the conclusions that that work came to is that if you look at the southwest region as a whole--Arizona and New Mexico--and if you think of them as an island, and if you were to take out one of the big pipelines serving the region--for whatever reason--freeze off or pipeline outage--there would be a pretty severe risk of that leading to reliability events.

However, given the nature of the interconnections between the southwest and California, and the northwest--basically the entirety of the Western Interconnection--and the fact that much of that region would be in a surplus condition in the winter, when those events might strike, it looked like there was potential to actually avoid a loss of load event, or a reliability event within the region, if other regions basically could share some of their surplus capacity with the Southwest during that type of an event.

And I think that type of dynamic is actually, even though the circumstances weren't identical, exactly kind of what played out for PNM during the 2021 winter storm Uri in terms of being able to find some market purchases from outside of the region to help prop up the system.

WRA: Source of Gas Generation Data

What are the sources of your gas generation outage data [Slide 11]?

Grid Strategies LLC Response

Most of that stuff came from GADS [Generating Availability Data System.] I didn't do these analyses. So, I'm not claiming to know the exact methodologies we're using in any of these. GADS is the data set from NERC, the common one that's used for a lot of these studies because it's the historical data set.

For future scenarios, the PJM New England studies, for example, they used historical performance during the [2014 2015?], polar vortex or other events like that, and kind of extrapolate that forward and said, "Okay, this is the test event that we're going to use to kind of define this and go from there."

I am, again, just trying to bring some ideas here. I'm not claiming I have all the answers of how to do this. But I do think the big takeaway for me is that we need to do something critically on the quantitative side, I think, to account for these very real risks. If we don't, we run the risk of flying blind.

Technical Session #8: November 2, 2022

Member of the Public: Permian Gas Flow

In the past, we've seen some basis differences between the New Mexico and Texas sides of the Permian, partly due to a lack of gas processing capacity in New Mexico and less pipeline takeaway capacity here. That trapped gas in New Mexico can help lower price for New Mexico utilities. Has that changed?

Initial Response: Siemens

We do consider that. So, part of the model that we have looks at demand and supply. So, if supply is decreasing, we reflect that. And if demand is increasing, or decreasing, that's reflected as well. So, we look at how much gas is flowing on each pipeline to determine what the base is or the price is at those hubs.

A lot of that Permian gas not only obviously goes to serve the LNG export market, but it also goes to Mexico and some of that gas actually flows across to Arizona and California as well.

So, there is gas. That Permian gas is going out west more. In terms of prices, because you have a shorter leg, and the fact that you have a Permian price or Waha price that's below Henry Hub, that's why you would see lower prices in New Mexico. Does that answer your question?

Member of the Public continued.

Yes, that that was what I was driving at. Part of the New Mexico gas used to have to travel into Waha, and then to get west. So, it sounds like all that's taken into account.

Siemens continued.

One more comment.

The upper band there [on Slide 19] for CO2, we look at that as a P95 type case.

Another way we also look at it is in terms of if the political system or government was very keen on achieving this as an environment where everybody agrees, you get some action. And then, in that case, you could say, “Okay, well, we agree that climate change is a big problem, we're all going to do whatever needs to happen to solve that.” And if everybody kind of works together, then this is what that black line could look like.

But in reality, we know people don't necessarily play that well in the sandbox. And then you get those other scenarios.

InterWest Energy Alliance: Volatility in Gas Forecast

How has volatility been incorporated into gas forecasts after winter storm Uri? Is there a method to back cast this methodology to test its accuracy?

Initial Response: Siemens

When we do volatility, we do volatility in three increments.

For the first three years, we go back and look at the volatility that's happened over the shorter term. And then, as we move past the medium term, we use a five or 10 year. And then, when we go longer term, we use 15-year prices to come up with those volatilities. So that's what's reflected in our analysis.

We don't necessarily say, “Okay, well, something happened last year, so, let's reflect that going forward for every year.” We're still more conservative from that standpoint, in terms of how we model.

PNM continued.

So maybe that'll drive another question, at least on our end. When you're talking about the statistical envelopes, let's say, your P10, P50, P90 values, and you're coming up with some baseline and then getting an envelope around that statistically, you're having to put in some volatility parameter--whether it's a mean reverting GBM, or whatever, statistical stochastic process you're going to fit around that.

And you're [likely] going to use some historical data to parameterize that stochastic process.

And so, you are likely capturing the increased volatility from gas prices that corresponded with the hurricane Uri event when determining that volatility parameter that you would use to determine your envelope. Is that right?

Siemens continued.

Yes, exactly. We are using historical. It's just that the historical we're looking at is, for the shorter term, sort of what happened in the near term.

And then, longer term is based on more typical 15-year type volatility.

So, we are looking at historical volatility. And I believe, I'm not the quant [quantitative analyst], but we look at daily volatility over those time periods to come up with the three areas of the forecast.

PNM continued.

And typically, at least with stochastic models, it's not like a deterministic process where you're going to go back and try to ensure a back cast; this is closely to a single point estimate as they call that in the statistical terminology. But you would want to ensure that you're within your stochastic process outcomes, that you're talking about a 90% confidence interval, and that what you might have seen historically fits within that.

So, maybe the better question, or could we address, is if we were looking at the envelopes that are generated is a Uri type event and the volatility associated with that potentially going to fit within that envelope, or is that such an extreme case, that's more of a one-in- 100-year type of event that would be outside the typical confidence bands.

Siemens continued.

I would think if you have a one-in-100-year [event], it would probably be outside of the confidence bands. However, some component of that would be reflected in it. So, we don't look at that year and say, "Okay, well, every year is going to be like that. Let's see what that looks like."

You mentioned stochastically, when we do the stochastic analysis, we effectively have a band that goes from P5 to P95. And that's again developed statistically, like you said, but I would say, "No, an event like Uri could be outside the 95th percentile."

But keep in mind, this is a P90 on the gas side that we have. So, if we were to do a P95, it might capture that.

PNM continued.

Right, and then when you're simulating out those stochastic processes, whether you're doing 100 or 1000, or whatever simulations, and typically, in a random walk style analysis or something similar, there's always the probability that that Uri style event could manifest through that random process.

But the probability of that is going to be very, very low. So, the question would be, maybe, "How many iterations or how many forecasts would you have to simulate before you see something like Uri?" And Uri was a pretty extreme event. So, I'm assuming we would think we would have to generate a very large number of random walks in order to see that type of event manifest.

But you're again, just trying to address the question here.

InterWest Energy Alliance continued.

But I guess my question is really, how [do we do] weather modeling [if]--I think there is an understanding--extreme weather events are becoming more common and not going to remain the same? So, I think looking at the historical likelihood is probably not the way to accurately capture the next 20 years of these events if--and I think the agreement is on the weather modeling side--these historical events are going to become more often and potentially more than a one-in-100-year event.

PNM continued.

When we're talking about weather, we would tend to agree with you. And so, in terms of the weather that goes into our renewable production profiles and our demand forecast, that is a little bit different. We would leave it up to Siemens to talk about how that may go into the gas forecast.

But specifically talking about the gas forecast, we, through the Energy Transition Act, can't add any heavy carbon emitting resources. We're not looking to add coal plants or combined cycle facilities, something that's going to have significant carbon emissions due to the RPS requirements, the carbon free requirements, and the carbon intensity requirements that we have to meet.

So, really, the natural gas price forecast, for all intents and purposes, is really going to drive the utilization of our existing gas fleet. And that's already in the ground and not really subject to future looks at until we start thinking about when we're going to get out of those plants. Any type of new natural gas additions would be very low-capacity factor, peaking plants that would be used solely for reliability purposes, break glass in case of emergency.

So, we don't think that trying to get extreme weather analysis into the gas forecast is necessarily the best use of resources, given the framework that we're looking into here. And when doing planning, we're always starting with a weather normalized load forecast, and then we're trying to get production profiles renewable that are associated with those. And then we'll start to look at changes and things.

So, you'll remember that the resiliency report that we did, and talked about in our second and third meetings, kind of drew out some key differences between different portfolio types and how we might address the resiliency needs of the system--it will be generating, and we'll be talking in our next meeting about the load forecasts that we'll be using, along with weather normalized load forecasts that will be used for planning and different scenarios. We're also going to be looking at some P90 value forecasts and how that might change the overall planning requirements.

So, we would say that the discussion on weather is more targeted, we would think, to the renewable production profiles and the demand forecast, not necessarily the gas forecast here.

InterWest Energy Alliance: Hydrogen Capable Turbines

Are the capital costs for the CT (Combustion Turbine) [reflective of a] 100% hydrogen capable turbine?

Initial Response: Siemens

These turbines are probably not. Most of your utility scale turbines are the larger ones, and they're generally speaking, depending on exact model 30% [hydrogen] capable today with little to no change.

There are some models that are 100% capable: They tend to be the smaller machines, think more like 50, 60, 70 megawatts, units that used to be more in oil and gas service running compressors in the field. We're used to using sort of weird gas combinations and things like that. These can be upgraded for nominal cost over time if needed. That's actually an interesting option to think about in later years--to keep assets sort of functioning and useful as hydrogen becomes available.

PNM continued.

That's exactly how we looked at it in our last IRP, and we were planning in this IRP that there's no requirement that we have to burn 100% hydrogen today; we just have to meet our RPS, our carbon emission intensity requirements, and eventually the 100% carbon free requirements.

To the extent a natural gas, aero derivative, or combustion turbine could be brought on the system for capacity purposes, run a few percent of the hours in the year to maintain reliability. and then, over time,

be converted to 100% hydrogen capable when we need to be 100% carbon free and adding on a conversion cost at that point, that is how we handled it in the last IRP.

As indicated, the conversion costs, especially when you think about going forward in time, are going to be pretty minimal. There's not that much that really needs to be done to the turbine, It's just the fuel injectors, the first set of blades, some things that are not a complete overhaul.

Siemens continued.

That's correct. The bigger challenge may be just the hydrogen getting the same amount of energy. Hydrogen is sort of roughly three times the volume of natural gas. So, there may be some piping changes. But the turbine itself is not too bad. Control systems are a real nominal upgrade.

It really depends on how far you're going to go. You can phase it over time, go from 30%, to 50%, to 70%, to 100%, kind of stage your cost. if you will.

PNM continued.

Right. And as indicated, volumetrically, you need almost three times the amount of hydrogen, the relative natural gas due to the lower heat content. And so, even if you're doing heavy duty blending, until you do 100% hydrogen, you're probably not getting much past 50% carbon reduction even without an 80% blend.

Siemens continued.

So, you can get some advantage for a certain price, and each project can be sort of considered on its own merits.

PNM continued.

We are keeping all options on the table. We don't think that hydrogen is a silver bullet. There's a lot of different things that are going to go into decarbonizing the system, but certainly something like

hydrogen that can provide long term storage can provide reliability functions. A little bit of inertia and spinning masses and other such things has a lot of benefits to it. And there may be other benefits outside of just the power electric generation sector for hydrogen, such as the transportation sector, heating sectors, things like that.

Siemens continued.

That's right. And the IRA (Inflation Reduction Act) provides a lot of support for hydrogen and some of the other decarbonizing technologies.

PNM continued.

Right. And that's not built into these forecasts, as you've indicated. These are all pretty [much] IRA, capital assumptions.

rPlus: Battery Costs

Do the battery costs include total system cost, and do they include augmentation?

Siemens Response

These are total system costs. These do not include augmentation. If augmentation is appropriate for a given client arrangement, if you want to keep the capacity at a certain level, then we build that in when we do the modeling. So, we'll phase out a certain portion of the capacity and add it back in at the price and at the time appropriate.

rPlus: Timeframe for Project Operation

How long a timeframe for project operation economic life will you use?

PNM Response

That's really resource dependent. It depends on what type of technology and what type of resource we're talking about. For something like energy storage, it's probably the battery energy storage --lithium ion--that's going to be in the 15-to-20-year life[span] and the same thing for solar, but maybe solar will be 30 years. We have to take a look at what we're getting from some of the technology manufacturers. Same thing for wind. When we think about natural gas, combustion turbines [are] probably going to be a little bit shorter of an economic life to reflect being carbon free by 2040.

In the last IRP, we assumed we would depreciate any new natural gas resources by 2040. But then in 2040, they would incur a new capital cost to convert them for full hydrogen operations; that would start a new depreciable life.

For some of the other things that we're seeing in our RFIs, the longer lead time and larger plants like pumped hydro, using something more like 40 or 50 years is probably not inappropriate. And then for some of the other technologies that are a little bit more nascent, we'll have to do some research and determine what we think is appropriate for an economic or technological life that we'll be using.

All that will be published in our Integrated Resource Plan appendices--maybe Appendix I. We have to double check that, but one of the one of the appendices requires us to publish all the different candidate technologies we're looking at and the different economic life, technical life, operating characteristics, capital costs, things of that nature.

Member of the Public: Decentralization of Demand

Where in the futures and sensitivities models do you factor the possibility of decentralization impacting on demand for PNM services?

Initial Response: PNM

Do you mean decentralization of resources or decentralization of load? Could you clarify?

Member of the Public continued.

It just seems that looking far into the future, where the possibility is of people to kind of fork off, requiring PNM or backing up at home with their own batteries, all that kind of thing.

It may be too early, but I just keep wanting to see that somewhere rattling around in our thinking because customers could peel off in different ways. And that could impact the company in many ways. So, I don't know, it's probably demand.

PNM continued.

Thanks for clarifying.

The way that this is being considered is through our demand forecasts. The IRP, again, looks at just PNM's retail customers. If a customer were to become completely self-sufficient, and no longer be a part of the PNM's retail system, they would not be included in the load forecast. That's not an obligation we would have to serve.

If the customers are incorporating their own resources behind the meter through additional adoption of behind the meter photovoltaic (PV) rooftop solar, essentially adding their own batteries behind the meter, those are things that we are incorporating through the load forecast.

So, we have a specific component in the load forecast that assesses a forecast of behind the meter PV adoption. And there's going to be four or maybe five different behind the meter PV forecasts. One of them will be trying to back out all existing PV on the behind the meter PV on the system. One will be assuming there's no new incremental behind the meter PV. Then, there's going to be three different incremental behind the meter PV forecasts.

And so, each of these forecasts can be used as modifications to the overall retail load forecast and would reduce the amount of system requirements that would have to be added and, in turn, reduce the amount of retail sales to support those customers. That would be accounted for--with additional behind the meter storage additions.

Again, that would end up depending on how [those modifications] are operated. If they are operated just on behalf of any individual customer for their own benefit, that would manifest through a change in the load shape in one way.

On the other hand, if we were to look at the establishment, once we have AMI (Advanced Metering Infrastructure), of perhaps a distributed energy resource management system, we can start to model the behind the meter resources as something that has full visibility--not just a load modifier, but a dispatchable combination of resources that PNM could operate or dispatch, through an aggregated system for the benefit of the entire system. Thus, that would reduce the need for additional resources on the system.

Those are the ways we're thinking about it for this integrated resource planning cycle, and we'll have to continue to think about it going forward. Additionally, there's going to be independent forecasts for different building electrification as well as transportation electrification forecasts. And then a time of use, or time of day rate pricing sensitivity that will say, "Well, if enough customers joined this time-of-day pricing program and modify their behavior, how might that change the overall requirements of the system?"

So, that's the way we're looking at, at least from the supply planning point of view. And we would always keep in mind as well, when we're establishing what the needs of the system are, and we determine that so much solar might be needed, or so much storage might be needed, even if it's coming in at the utility scale, that it doesn't mean it's something that has to be done by the utility. It could always have a part for the customer to enable them to be part of the transition, so long as the resources are dispatched for the benefit of the system, and not dispatched for the benefit of any specific customer.

We know that this has been an ongoing question for years. And we hope that [this response] helps to think about the way we're looking at it this go around, from the integrated resources planning point. The key has to be about just what are we doing for our retail customers? And then how can we take lots of small, distributed resources, and think about how they could be aggregated up to the system level. Because when we're looking at the IRP, it’s always looking at the bulk transmission system; we're not modeling down to the distribution levels.

Member of the Public continued.

Thank you.

I keep raising this because I do see things as being pretty far, some of it's pretty far, out in the future. I'm not expecting immediate answers of any sort. I just want to understand how to think about it. And you're helping me a lot.

Technical Session #9: December 15, 2022

PNM: Higher Non-Solar Hours

So, the on-peak non-solar hours, the reason that's higher, that's mainly due to the fact that those would be your morning ramp and your afternoon ramp prior entering the evening hours? Is that right?

Initial Response: Siemens

Correct. So, your load is still high, but your solar generation is not quite there so it's your kind of 8 a.m.--I think on peak solar is 8 a.m. to 5 p.m.--and your 6pm to 7pm time period is included in those on peak non-solar hours.

PNM continued.

My other question is, are you using the standard block--like, 6 by 16, 6 days a week--as the on peak definition and then the subset of the on peak solar is at 8 a.m. to 5 p.m.?

Siemens continued.

Right. We just broke out the solar hours.

InterWest Energy Alliance: Storage

This curve to me does not show any penetration of storage (referring to Slide 14). Is that correct?

Initial Response: Siemens

It doesn't necessarily reflect it very well in this curve, but there is storage built into these prices.

PNM continued.

Each of the portfolios uses an optimized capacity expansion in order to come up with the overall penetrations of solar wind storage, everything across the WECC in order to meet the total WEBB capacity and energy requirements. The prices from the dispatch, or what's shown here, are based on those optimized portfolios.

Siemens continued.

These two graphs are the same. They represent the same exact thing, just at a different pricing hub. So, any storage that was built within the capacity expansion for the overall West region is reflected in these price curves. And so, storage may have alleviated it.

I couldn't tell you exactly what this graph would look like if storage was not included,

But even despite the fact that there is storage, you do still see kind of a pretty intense duck curve.

Sandia National Laboratories: Pricing at Palo Verde

Does the Palo Verde on Slide 14 refer to the pricing at the Palo Verde hub,

or the price and the Palo Verde power plant?

PNM Response

It's the hub price. Spot price trading to occur at the Palo Verde hub to reflect going forward.

InterWest Energy Alliance: Cost Assumptions

My question goes back to your slide [Slide 11] on your market drivers and capital costs in particular. You mentioned a number of factors that you looked at on those cost assumptions and one of them was

some preliminary assumptions on the IRA [Inflation Reduction Act]. I'm wondering if you can give us some more clarity or detail on what your assumptions were on the IRA. I understand the rules have not come out. It's early days for everyone but I'm wondering how you took that into account.

Initial Response: Siemens

So, these particular lines, or outlook, these graphs don't reflect the IRA. We have a couple [charts] here, and these are preliminary. These were developed shortly after the IRA was passed in August [2022], so there are probably some minor changes that have gone forward into this.

But as of this outlook we have a solar ITC at 30% through 2032, dropping to 26% in 2033 and then 22% in 2034 and then down to 0 after 2034.

After that, there is no ITC for solar, hybrid solar, hybrid solar plus storage, and standalone storage.

And then we have a 15-dollar wind PTC going through 2033, as well as a $15 PTC for SMRs until 2032, and a $35 PTC for CCS units through 2033.

PNM continued.

Just to clarify. Those assumptions were worked into the capacity expansion when you [Siemens] developed the power prices, but what's shown on the screen here does not have those assumptions worked in. And we are working with Siemens right now to put together the specific updates.

That will reflect that before we actually get into the overall hierarchy modelling. These curves were developed, and the scope of work was developed initially before the IRA was ever passed. So, that's why these are presented right now without the IRA impacts.

Member of the Public: Slide on Pricing

I'm not quite following all that pricing that was just presented [in response to that question from InterWest Energy Alliance on cost assumptions--regarding Slide 11]. Could we get a slide or something to show that in the future?

PNM Response

Yes, we can revisit all of the IRA assumptions.

What Siemens just spoke to was the provisions of the tax credits that are listed in the Inflation Reduction Act that was passed back in August [2022]. And then they were just saying, specifically, what each of the individual tax credits were that could apply to the different technologies.

InterWest Energy Alliance: IRA Tax Credits and Price Curves

I understand the curves here [Slide 11] don't reflect or include these PTC assumptions, but do you have a sense at this point how much [the IRA (Inflation Reduction Act) tax credits] will affect these price curves?

Initial Response: PNM

Of course, there will be an effect. I think the most important question is: "What will the relative economics be between the different technologies when [the IRA tax credits] are applied to all of the price curves, and what attributes are provided by the different technologies in terms of meeting the overall demand and energy requirements while maintaining reliability of the entire system?"

We heard Siemens say that in their capacity expansions, which didn't model all of the IRA tax credits, they saw predominantly solar, storage, and aero derivative or other combustion gas turbines being added in order to meet the flexible ramping requirements of the system.

InterWest Energy Alliance continued.

I guess my question still is do you have a sense of the extent [the IRA tax credits are] going to change your analysis here, or what you're showing in these graphs? Is it going to be a significant effect, or do you think it's just tweaking without really changing the trend here at all?

PNM continued.

These curves here are just talking about the overall cost, not the revenue requirements.

Revenue requirements would take the tax credits into account and again it's really the relative economics between the resources that are going to determine what the overall portfolio is. So, we don't know that we're prepared to speculate on any individual technology curve here--how it may or may not be impacted by the tax credits.

Again, what Siemens says, and what we would expect to see likely in our analysis as well, is you're going to see a proliferation of renewable resources, energy storage resources, and likely some combustion turbines in order to help with those flexible ramping requirements until you get to a point where you can't have any carbon emissions.

Sandia National Laboratories: Methodology for Hub Pricing Forecast

Could you elaborate on the methodology used to obtain the hub pricing forecast? You mentioned that you did a capacity expansion model on the Western interconnect. Did you then run a nodal production cost model for each year, or the forecast obtained from the capacity expansion planning model?

Initial Response: PNM

It's running a zonal pipe and bubble format across the entire WECC but doing an 8760 for each year.

Siemens continued.

Yes, that is exactly it. So, we do run our capacity expansion to get the overall WECC build out. And then from there we incorporate that into the WECC; we run a zonal 8760 with the various price hubs. There are different bubbles, and we just get it from that zonal output.

PNM continued.

And that's very similar to what we're doing in-house behind the scenes here as well.

We've brought in the full Encompass national database as well as the nodal version of Encompass.

We're still getting the nodal version of Encompass calibrated, but you wouldn't expect to run that for every year; you might do a few years of nodal analysis.

But for the internal price generation that we're doing, it's a very similar method to what Siemens has done here--taking their international gas price forecast and other market drivers, running them through a capacity expansion, and then a zonal production cost within Encompass as well.

So. here, what we're seeing is the results of the Siemens analysis from the bottom up.

Member of the Public: Hub Prices and IRA Credits

Will the hub prices change as the IRA [Inflation Reduction Act] credits are included?

Initial Response: Siemens

Our preliminary view of the IRA tax benefits are included within these hub prices. The PTCs and the ITCs that were incorporated while creating the build out were incorporated into this particular model and baked into these particular prices [on slide 14].

PNM continued.

So, these prices would already have embedded within them the effects of the IRA.

[Speculating], this would be more reflective, still, of overall a bilateral trading, or maybe even a quasi-day ahead market.

But maybe [if Siemens would] comment on the dispatch, it's not a bidding logic, though, that you would see in an overall organized market structure.

You would probably think that the prices, especially in the solar hours, if solar resources are taking PTCs and offering them into a market, like the wind resources in MISO or SPP, at high negative prices, could actually put a much further depression on prices in an overall organized market structure.

Siemens continued.

Right, and there is a bidding availability within Aurora, so you can [model bids] at those negative prices. [For modeling purposes], it usually isn't necessary to bid those negative [prices], since solar hours already have such low cost--[solar is] going to generate that free energy, because it's got a PTC.

But [IRA tax credits are] largely used within the capacity expansion model, and the selection and the economic benefits of being selected within the capacity expansion and the overall choices for the capacity expansion, not so much for the dispatch costs necessarily, although it does; it is included within the dispatch costs as well.

Sandia National Laboratories: Carbon Price Forecast

I have a question about the carbon price forecast. Could we flip back to [Slide 10]?

The reference case forecast reflects a carbon policy starting 2025 ... On the federal price, do you foresee any possibility that the incoming Congress will pass this, a federal CO2 price, or what exactly is the story that would explain a federal price going into effect in 2025?

Initial Response: Siemens

I personally cannot quite comment on this one in detail.

Carbon and the gas prices were viewed in a little more detail by someone else. I'm more than happy to jot that down.

PNM continued.

We can take that back.

Overall, the thought process that we've seen with carbon price development is we've been anticipating federal action for a long time. And there really hasn't been any for purposes of getting a baseline target here. We don't view this as being unreasonable. It may be offset by a year or two, but we do anticipate that in the future there is going to be some type of federal action; it's just a matter of when it starts.

Overall, the carbon price forecast really isn't going to be a predominant driver in the overall selection of resources, mainly due to public policies requiring specific RPS requirements or carbon emission reductions.

Whereas in the past, you might have needed that carbon tax in order to incentivize different actions, at this point, given all the public policy agenda items that are out there for various entities in the WECC, it's those things that are going to be driving the portfolio changes, and any potential carbon action on the tax side is less of a driver.

Sandia National Laboratories continued.

Yes, that makes sense. I would tend to agree that the capacity selection will be driven by RPS and tax credits, but I imagine the carbon price assumption may affect the production cost modeling in terms of clearing prices for power; if the marginal unit is a combustion turbine, the power price will be different, depending on whether or not that resource is subject to a carbon tax.

PNM continued.

Certainly, and we would imagine that if we look at some of the hourly data, that we see

greater effects of the carbon prices on market prices for the nonsolar hours in the near term. But as the underlying portfolio changes over time, as you move further out in time, there's less and less impact of any CO2 price on the overall hourly market prices.

PNE USA: Copies of Siemens' Slides

I was just wondering if we could obtain copies of Siemens' slides.

PNM Response

Yes, all of these slides will be posted to our website following the presentation here today. So, if you would just check back on the website, you'll see that any of the presentations from this meeting or previous meetings can be downloaded there.

InterWest Energy Alliance: Increases in Temperatures

In your trends that you're seeing — if you could go back to your high temperatures [Slide 26] — I understand that's [an average] over 24 hours. But are you seeing an increase

in daytime temperatures or are you seeing an increase in nighttime temperatures or are you seeing both or neither or a blend?

Initial Response: Itron

Yes, we've been looking at that. Overall—the growth—there is some warming. It's on the verge of statistical significance; it's T-statistic is close to 2, a little under. It's about a half degree for a decade.

So, it is there in the day; you see it if you look at the darker orange numbers. There's a few more days above 85 as we move to the right, except for 2003, which has the most days, so, it kind of pins it down on the left.

But, yes, there is some warming going on, but it's nothing like what we will see when we get to the extreme scenario. That's a way past what we would ever get from a global warming scenario if we did one.

InterWest Energy Alliance continued.

I'm just wondering if you're seeing that primarily in daytime temperatures or nighttime temperatures.

Itron continued.

It's a little bit of both.

The nighttime temperature is a little tricky. You basically have a very dry climate there and so the nighttime temperature can drop pretty fast. Unless it's humid, and then they kind of get stuck at the dew point. And so, there is some of that going on.

We've seen that in other places that the highest high isn't necessarily getting that much hotter, but it's not cooling off as much at night.

It's warming, but a lot of the warming is not in terms of hotter days; a lot of it is in terms of less extreme cold days.

Member of the Public: Behind the Meter PV

Do the behind the meter PV numbers include community solar?

PNM Response

They do not. The community solar is going to be interconnected on the distribution system. It's not going to be behind a customer meter. That will be accounted for on the supply side, not on the load side.

InterWest Energy Alliance: Non-residential Forecast

Looking at the nonresidential curve on that top graph [Slide 33], and it looks like you're assuming or forecasting that nonresidentials, which I assume include both commercial and industrial—kind of your medium commercial and your larger load customers—are going to be adopting some behind-the-meter generation, but not at the same rate as residentials, or not to the same extent.

Is that the trend that you guys have been seeing so far: that commercial and industrial customers don't want to use behind-the-meter so much; they just want to use more of PNM's system?

Initial Response: PNM

We can't speculate on the reasons they would or would not choose to do behind-the-meter solar, but what we can say is, from the interconnection data and what is presented here, initially, the nonresidential installations exceeded the residential installations. But in more recent history, and what we expect to see going forward, there is a much greater adoption rate for residential customers versus nonresidential customers.

Itron continued.

Yes, it crossed over in about 2016. They were tied and then the residential has just taken off compared to the nonresidential. And there were some big additions here in the water and wastewater area, where they have sort of put in enough solar to sort of zero out their loads in the high price-10 years period for them. For some of those, there's actually a reason why they've taken it to the point that they have.

.

InterWest Energy Alliance continued.

I just was wondering what your assumption there was based on. Is it based on what you're seeing now, what you hear from commercial and larger customers and what their plans are in the future, or is it just a guess essentially based on not much?

Itron continued.

The residential tracks real well with the EIA, Energy Information Administration, forecast for the mountain region in terms of kW per household, and the business one tracks real well with their kW per square foot, kW per employee kind of numbers.

So, that's what we've sort of tied into there.

Sandia National Laboratories: Assumption for Increase in Residential Solar

Could we elaborate on the assumptions used for the increase in the residential solar, and does this assume full AMI [Advanced Metering Infrastructure] deployment?

Initial Response: PNM

The underlying assumptions would be more along the lines of there's no hosting capacity issues, there's no delays in interconnections, tax credits are extended, etc. All of those types of things that will influence the overall customer behavior.

Now, this, again, is not up to PNM to tell customers to go and do this. We can't force them to do anything. This is all up to customers and whether they want to spend their own money on installing these systems.

Itron continued.

Yes, that sounds right. There is a point if you extend this line at that slope for another 20 years or so, where it creates problems. There's got to be a place to put [the solar generation]. There are definitely things that are going to have to be done to support this level of adoption.

PNM: Net Metering

Does this also assume that net metering is allowed to continue, is that an implicit assumption within the model, or is that not considered?

Itron Response

I don't know that there's an explicit assumption on that, but certainly anything that's tied into recent adoption rates, those adoption rates reflect whatever arrangement is in place.

And, obviously, if you change that and say, instead of giving you full retail price, we're going to give you the marginal value of that, that would be a big difference in terms of the economics for the customer.

New Mexico Attorney General's Office: Electrification Scenario and IRA Tax Credits and Rebates

Does this electrification scenario [Slide 41] incorporate the new IRA [Inflation Reduction Act] tax credits and rebate programs?

Initial Response: Itron

No, not explicitly.

PNM continued.

This would be an assumption that there's some New Mexico policy that's enacted that requires all new construction to be electrification-only and incorporate some conversion of existing homes and dwellings from natural gas heating to electrified heating. Is that correct?

Itron continued.

Yes, it would probably take PNM's involvement to make this happen. Some sort of incentive to get people to make these changes because it's costly—the change to convert systems.

So, we didn't model this is an economic decision given tax incentives and all that. These are the assumptions: When a new home was built, it's no longer going be natural gas or propane, and that 2% convert. Those are sort of the assumptions behind the scenario.

Sandia National Laboratories: Voluntary or Mandatory Time of Use Rate

For this analysis on the rates [Slide 42], was it considered to be a voluntary or a mandatory time of use rate?

Initial Response: Itron

What turns out, if it's voluntary, is that people have to opt in. Some people will do that, especially if it's advantageous to them.

But, if it's an opt out program [where] it takes some action on your part to not get put on it, then most people just stay on it because, from their perspective, they don't even really hear about it or know about it.

So. This is an opt out program and the assumption is that 20% of the people opt out, 80% stay on the program.

PNM continued.

So, in other words, it's a mandatory time of use rate for residential customers, beginning in 2030. But as your fourth bullet there says, you're assuming that 20% of the residential customers who are put on this program opt out of it.

Itron continued.

Right.

InterWest Energy Alliance: Summer and Winter Peak Days

I'm seeing your numbers here [Slide 31] about your peak, your summer peak day being 2.6 degrees warmer, your winter peak day is 12.2 degrees colder. I'm going to reiterate my [previous] question [to be clearer.]

For example, the summer peak day, being 2.6 degrees warmer. Is that effect

more from nighttime temperatures being warmer or daytime temps being warmer? And then same question for your winter peak day being 12.2 degrees colder. Is the larger contribution to that from nighttime temps being colder or daytime temps being colder?

I understand what you're looking at is an average [Slide 29].

I'm just wondering—you may not have this information—but. In developing your average, were you able to notice or identify whether the contribution to the change in temperature is more from daytime or nighttime?

I understand you might not have done the analysis.

I'm just wondering if when you did, did you notice that at all?

Initial Response: Itron

We didn’t really study that and it doesn’t show at all here.

These are just the average temperatures and. In fact, in the actual modeling of the hourly loads, we just use the daily average temperature at this point. We’re not actually using the hourly temperatures, although that’s certainly possible. But we didn’t. We’re just using current days—average temperature in the prior two days—average temperature to drive those hourly models.

I’ll go ahead and put something together that looks at this top row.

And we’ll just get the mins and maxes, just see what see what, in fact, we’re doing for this hottest day, [what] is the average of this day.

And those days that have a max and a min, we can certainly look at them, and all these days have a max and a min.

So, we will just look at them all and see what we think.

InterWest Energy Alliance continued.

Thanks.

It just seems like that's an important consideration. I understand from climate research that especially here in the Southwest, some of the effects we may be seeing in temperature, in average temperature increases, may be more from increases in nighttime temps versus daytime temps.

But that of course may have effects on your loads as we've been seeing here and all your graphs and so on.

So, I just think it would be useful to kind of tease out, if you reasonably can, what is actually driving those changes in temperature, and whether that makes a difference to your forecasts.

Itron continued.

Yes, we have all the hourly data, so we certainly can pull those max and mins up.

PNM: Daily Average Temperatures

On the modeling side, at least, you're calibrating 24 different hourly models to that daily average temperature. And so, I'm assuming, of course, those are going to be statistically significant.

So, you're capturing the effects of the increasing daily temperature, whatever the daily temperatures are on an individual hourly basis. It's not like you're ignoring the hourly piece of it.

And so, if you were to change this framework up and look at more hourly data on the temperature side, you'd be recalibrating each of those models and it probably is not going to change that relationship much.

And when you do this, each time you reforecast a load, you're recalibrating to more current load/weather relationships. So, if there is a change in that relationship, that's going to be captured within the calibration process before you reforecast.

Initial Response: Itron

Yes, that's true.

The actual hourly model uses data, let's say, maybe 2017 to 2022, somewhere in the last 5 years or so.

It is possible to do hourly models that use the hourly weather hour by hour and we often do that in operational forecasting systems. So. next day forecasting.

But for the sort of more long-term look and just load shape forecasting, it just becomes more complicated-- especially defining normals, so instead of using an actual hourly weather forecast, now you're having to define normal hourly weather, which gets us into these issues, like, what is the right thing for the low and the high.

So, a lot more there, but there is definitely the possibility to go down that path in future efforts. if that's an important thing to do, to actually use the hourly weather data in the models.

PNM continued.

But from your work, so far, what you've seen is that's more important in near term, operational forecasts and less so, in long term, 20-year resource, planning type forecasts.

Itron continued.

Right. In the operational forecast we're bringing in hourly cloud cover and hourly wind speed, and solar radiation, and all those things.

Even then, it's not just the current hours temperature; the lag hours matter as well. And even the prior day.

So, it's a much more complicated model and it's worth doing that extra complication for that short-term, operational forecasting.

PNM continued.

On the long-term side, it's not necessarily worth that, what we need to make sure, what we do, is have a reasonable enough forecast capturing some of those extremes.

That will allow us to have a system that's resource sufficient, having enough reserves to make sure that if we get into the operational hour and things are going a bit different than expected, we've got that additional capacity to ensure we can safely and reliably serve our customers.

New Mexico State University: High PV Scenario

As I'm reading it, the high PV [photovoltaic] scenario included 1,141 megawatts of total PV on the system [Slide 35].

Looking at the 2020 IRP most cost-effective portfolios (MCEPs), the no-new-combustion scenario, obviously that's the scenario that would end up with the most PV, and that portfolio has 3,165 megawatt hours of solar.

This doesn't line up in my mind that our high PV scenario from last time around [which] appears to be 3,165. You seem to have about one third as much solar in what you've modeled.

So, maybe someone can explain this and if not, would you please do a scenario that matches what I expect will come out again this time in the model?

Initial Response: PNM

You're actually comparing apples and oranges there.

What we have here is the behind-the-meter PV impacts. And if you look at that bottom right plot, you'll see that there's actually a little bit more than double the amount of expected behind-the-meter photovoltaic additions that customers would put behind their meter in this IRP forecast compared to the 2020 IRP.

When you're referencing the 2020 IRP, it is the amount of utility-scale solar additions

that were added over the forecast period.

So, what we would expect likely to occur is, because there's so much more behind the meter solar photovoltaic in this IRP, there probably is going to be a decrease in the amount needed on the utility-scale side.

New Mexico State University continued.

Okay, that makes sense. So, right, because [Itron is] forecasting load, and this is part of net load, it's important to their modeling, but the system-wide resources provided by PNM probably don't factor in here. Do they factor in anywhere?

PNM continued.

If we go back to the slide that shows the hourly loads and the effects of the behind the meter PV [Slide 52 "Hourly Loads"], the yellow there is the effects of the behind-the-meter PV. And so, then anything that's not in yellow, we're going to be designing the system to meet those new customer demand and energy requirements.

And so, if we think there's going to be more and more of that load met by behind-the-meter photovoltaic, we're going to have less utility scale, we would say energy resources, but we're going to need still probably just as much if not more storage and other capacity resources in order to make sure that we can reliably serve our customers.

Now, when we put this into the model, we will have within the model, the loads, the meter PV. And then [we would] be optimizing a capacity expansion portfolio around that for utility scale resources that will meet the rest of the customer demand and energy requirements.

[Speculating], this is more than double the amount of behind-the-meter PV [currently on the system], [and, when also considering the community solar additions], we're going to see less overall utility-scale solar added to the system as a result.

New Mexico State University continued.

Okay, [that] makes sense about the behind-the-meter as I look at this lower plot

where almost 1000 megawatts of power is provided by solar in the middle of the day. That must be all the solar. Right? Not just behind the meter?

PNM continued.

No, that's just behind the meter.

New Mexico State University continued.

So, where is the other solar?

PNM continued.

This is all relative to the load forecast. [This is only the BTM solar embedded in the load forecast].

Sandia National laboratories: Number of Variables

[On slide 54] it seems like there's a lot of different variables there with different high, medium, and low assumptions. And then there's probably even more.

I guess you do have economic forecasts in there. So, I guess, in general, there's a lot of variables with three different choices. So, it turns into a very large combinatorial problem.

I was just curious if you could comment on the methodology for coming up with these different combinations.

Was it based off of just going back and forth on what scenarios you think are critical and would have an effect on your IRP outcomes? Or was there some other kind of mathematical scenario reduction techniques out there? That might be getting too into the weeds here.

When do you know when you feel comfortable with all these scenarios and how you book-ended them?

PNM Response

This table kind of originated as a work product between us, Itron, and some other consultants that we work with, in developing the IRP.

And the purpose of the IRP is to make sure that we capture enough different future states of the world to be sure that our plan is robust enough going forward, that we can pivot as needed, depending on if circumstances have changed. So, this represents what we thought [was] a good combination of likely future states of the world from the load forecast point of view.

And then we've got different combinations of sensitivity factors and otherwise that would affect what the assumptions are on the supply side and economics associated with resource choices.

Yes, this is really what we're thinking would capture the range of the envelope that we would need to put together on the load side to be comfortable that whatever future state we have is going to be somewhat in there, that we've done modeling associated with it.

And we can start to, if we think we've missed something, for example, [we could] take some differences between cases that are similar, except for one sensitivity factor. We [could then] isolate that sensitivity factor and then maybe add that on somewhere else.

That's the general reason, or the general rationale behind these various scenario definitions--thinking to ourselves what are the things that we think will really be the main drivers in the load forecast, and how might they change as one-off scenarios, or within combinations with each other, and then how will that then flow through to the overall portfolios that we need to think about as we're developing our plan for the future.

Member of the Public: Fixed Tilt BTM Solar

Is the BTM [Behind the Meter] solar assumed to be mostly fixed-tilt?

Initial Response: PNM

The behind the meter is pretty much all fixed-axis, especially for the residential.

Itron continued.

Yes, I would say that we're assuming that [new installations reflect current installations regarding fixed-tilt].

My personal guess would be that it's almost all fixed-axis. But really [what we're] using is your measured generation data, so whatever mix is in your base is also in the forecast.

But again, my assumption would be 99% fixed or more. I don't think I've ever seen a rotating residential system. Most of the commercial system is parking lot shading kind of systems. It's all fixed. Wastewater guys, maybe, they did some [tracker systems].

But whatever is in the historical data is; we're just [using that mix]. We're just forecasting it to remain that way.

Sandia National Laboratories: Smart Meters and the Pilot Program

Can a residential customer participate in the pilot without having a smart meter installed?

Initial Response: PNM

[To clarify, you are asking if a customer would], in order to participate, either have to get an AMI meter or an interval meter of some sort, or could they participate with a legacy [meter]?

PNM (Pricing) continued.

No, what will happen is this: When someone signs up to be on the pilot, their existing meter will be swapped out for a cellular interval meter. So, it has to be an interval meter so that we can study, we can do load research, and [we can] understand how things are shifting.

We don't have AMI [Advanced Metering Infrastructure], so these are cellular meters. These are the same type of meters that the transportation electrification program is using also to load research for the EV rates that we have proposed.

And so, they cannot participate without having one of these new meters.

PNM: Net Metering and Time of Day Rates

If you were a customer that had a behind-the-meter photovoltaic [BTM PV] system, and you were getting a net metering benefit on the current residential 1A rate, would the value of net metering from BTM PV change as the time-of-day rates are implemented or if the customer enrolls in the TOD pricing structure?

Initial Response: PNM (Pricing)

Right now, because they're welcome to sign up for the [1 B] time of day [pilot] rate, it's not restricted to non-solar or anything like that. But there is that issue of then they're paid out of the rates in effect when their solar is generating. So, it's true that it is not probably a rate that they are going to want to sign up for at the moment.

But going down the road, because we would like to move to having time of day rates for the entire customer class, and at some point, making them mandatory, that is the long, long-term goal of this program.

But it's also true that this wouldn't be the only rate and there would be customer choice ... recognizing all these different things that customers bring to the system. When we design a new rate for a new customer class for net metering with rates specific to them -- that's a possibility too. In which case, it could be a time- of-day structure, but [one] that recognizes benefits that solar brings in or something like that.

So, that's certainly one of the issues that is in the issues section that we think about and that we want to talk about with the PRAC (Pricing Advisory Committee), that we talked about internally because having just this one time-of-day pilot be the only thing in 15 years is not our end goal. This is just one option.

And this is our first step to study who is interested in it, who can respond, and how we can make this better for the whole customer base.

PNM continued.

It could be, like you said, if there needs to be a different rate structure, maybe that helps the BTM PV folks, but also recognizing that the value of solar to the system goes down over time (as more and more of it is on the system).

Although a fair point to this would be is that this type of structure that you're promoting, even if you have behind-the-meter PV, it could incentivize behind-the-meter storage as well, to take advantage of that short duration, but high priced, net peak period.

PNM (Pricing) continued.

Exactly. And then when they discharge, they get a different price as well. The structure recognizes that. And so, that's a totally different paradigm than what we have right now, but it's what's coming. And so, we need to discuss these issues now so that we're ready.

PNM continued.

And in an ideal world, we want to see storage with every piece of solar that's out there. In order to make the system work as best possible, we want to incentivize storage as much as possible.

PNM (Pricing) continued.

For sure. Pricing and rate design is all about providing the price signals that encourage consumption that benefits the grid, the system, and the customer base as a whole. So, this is the first step at designing something better than what we have right now.

Member of the Public: The Pilot and New Residential Use Patterns

[How] might changes in usage patterns be included in the pilot as more people continue to work from home instead of going into a central workplace?

Initial Response: PNM (Pricing)

We would expect to see just the usage patterns of residential change from being a spike here in the morning [referring to Slide 74], as people are getting ready for work or school and leaving during the day. And then, they come home, and it ramps up to being more evened out or maybe not as much of a drop in the middle of the day, too, because not everybody will work from home, but more do. So, there's that.

But then that would also offer more opportunities for those people to be able to do things in the off-peak hours, such as, if they don't have smart appliances that allow themselves to pre-program -- whether it's the washer and dryer, the air conditioning, [or] the thermostat in the winter (although the thermostat's usually natural gas heating).

That might open it up to more people who could take advantage of this rate. That's one thought initially.

PNM continued.

And from just the overall [perspective], we saw from Itron's presentation the large increase in overall residential usage during Covid. That might give us an idea of what the usage pattern change might be if we examine, say, pre-Covid versus during-Covid times on residential hourly data -- what customers were doing during those times.

But that wouldn't reflect the change of the rates, though.

PNM (Pricing) continued.

Right, not at this point, but it could in the future and especially now is probably somewhere in between--not at the height of Covid when everyone was working from home, but not pre-Covid (and it will never go back to that).

And so, now we're still probably somewhere in between and as a few more years go on, we [will] see where it settles and then we can respond appropriately with price signals.

Member of the Public continued.

It seems to me that If there's some way to unobtrusively monitor this as part of the pilot, it will be important to know what the shift is of people not working in central workplaces.

And I think it's one of those areas where we kind of need to think of how we can find some measurement of that, too--just to track it better and get more nuance.

PNM (Pricing) continued.

Yes, I agree.

I wrote down your question and comment and I'm trying to capture comments that I can take back to the pricing group [so] we can continue to work on and refine.

So, as a part of this pilot program we're going to work with a measurement and evaluation group that will set up the pilot--like the recruitment strategies--so that we can try to recruit all types of customers, so we can see how they respond to the rate. And then we'll create a survey to measure how people are shifting, which load research data can give us an indication of their satisfaction with the program, and the number of people recruited. They'll help us create the goals for the program so that we can have some concrete measurements at the end to say how did this work.

And certainly, looking at the percentage of people working from home now is something that we should take into account. I don't want to say permanently working from home, but, like, whether they're working a hybrid schedule or not so that, as you say, we can capture the nuances of residential work patterns from home in the future.

Member of the Public continued.

Yes, I think the trick is this needs to be a bit unobtrusive because you didn't really want to get a situation of invading people's privacy to do that. And I think that makes it a trickier thing to have to figure out--what can be good markers.

Member of the Public: Use of Word "Peak"

I'm beginning to learn how your slides are working [referring to Slides 70-74], but, basically, "off peak" rates mean high peak, peaking renewable power/solar power generation. Do you think we could find another term so that we don't get the word "peak" used in different ways twice?

Initial Response: PNM (Pricing)

We can think about that. Although "on peak"/ "off peak" is the standard for how these rates are described. We'll take it back to pricing and think through it.

Member of the Public continued.

I'm just saying, and maybe it's just because of my long engagement with the process here at the IRP, [but] I think of peak, and then I'm looking at these rate charts and I'm seeing that the "peaks" we talk about are really the off-peak rates.

PNM (Pricing) continued.

There are off-peak and on-peak rates. So, yes, that term is used in connection with on and off throughout.

Member of the Public continued.

Yes, but right now we're talking about it in terms of rates; when we talk about generation, it's kind of like the reverse of that.

PNM continued.

I understand what you're saying and, you know, before we had the large proliferation of renewable energy, the rates aligned with the time period where you expect the peak load to occur.

What we're seeing now is because of the amount of renewable generation on the system, the high-cost hours no longer align with the peak load hours; they align with the net peak hours or the loss of load risk hours.

And so, when we are talking about peak rates we are talking about the high-cost rates, the peak pricing rates and not necessarily what aligns with the gross peak load hour because that's no longer the main driver of system risk and system cost.

Member of the Public continued.

And we don't have to have that conversation now; I've just realized I had to do a flip in my thinking in order to follow this conversation today.

PNM (Pricing) continued.

And that's an important part in terms of how we communicate this to residential customers because we're trying to get them to sign up.

I appreciate your comment and your pointing that out and it's something that we should think about as we create promotional materials to tell people about this rate.

Member of the Public continued.

Yes, I feel in every field we get caught in our jargon and our terminology and so we just need to know how it gets out there.

Sandia National laboratories: BTM and Storage

Hawaii doesn't require storage with behind-the-meter [BTM] solar. But the rate structure is such that nearly 80% of customers who went solar in 2020 included storage. Hawaii ended net metering and went to net billing. So, the proliferation of storage was done through price signals.

PNM (Pricing) Response

Perfect. That's the kind of thing that we're thinking of, or that we look to a state like Hawaii and then think about would that work here, if that's something that we want to consider.

So, thank you.

Member of the Public: Tax Changes with Loss of Fossil Fuels

As cost allocation will change, is some change in tax structure expected to make up for the government revenues that will be lost as we use less fossil fuels?

Initial Response: PNM

Setting aside gas taxes for vehicles and things like that, [where you] might have to come up with a miles tax or something, if you're talking about all electric fleet. But that's a little bit set aside from what we would do here at PNM; the PNM customers at least pay a gross receipts tax on their electric bills.

And so, that would be applicable to our total revenue requirements. So long as we're recovering our overall revenues, if any individual customer reduces or changes their usage patterns to optimize their change in their costs, that would change the gross receipts taxes to the state of New Mexico a little bit. But I think that's something that needs to be kept in mind with how the legislature is going to look at what their revenue needs are going to be relative to the overall gross revenues collected by all the different businesses throughout the state.

Member of the Public continued.

I think you've covered it. I think it's just we need to keep an eye on the fact that those fees that come off of the extractive industries are going to be impacted in those revenue streams, and they are going to be somewhere else in the system-- but they could impact us as well.

PNM continued.

Right, and I guess what I would keep in mind there is just because New Mexico goes to 100% carbon free for its electricity, or even if it goes 100% carbon free economy wide, that doesn't mean that neighboring states or other states who would want to purchase fossil fuels extracted in New Mexico couldn't continue to do.

So. I don't think that just because New Mexico goes carbon free means it's an end to the oil and gas industries within New Mexico, because they can sell those products elsewhere and there's going to be additional opportunities for them to try to come up with renewable natural gas, or hydrogen from SMR or any other things where they could participate in terms of trying to transform their business models to something that is more sustainable long term, if the overall United States is going to a decarbonization strategy.

But just because we go faster doesn't mean that's the end of the oil and gas industries--here in New Mexico, Texas, everybody else around us still will be consuming those fossil fuels.

Member of the Public continued.

I don't have an illusion about that, but basically, as we shift our fuel to the renewables, it does change that that mix. That's all.

Always like to keep these things on the table.

Member of the Public: Fixed or Variable Rates in Hawaii

Is the example of Hawaii indicating a move toward more fixed or variable rates?

[This question relates to an earlier comment from Sandia National Lab regarding BTM [behind the meter] solar and storage in Hawaii (Hawaii residential rate structure incentivizes storage paired with rooftop solar.)]

Initial Response: PNM (Pricing)

Yes, I would say it's certainly open for discussion about how we move forward. We're aware of Hawaii as a state with high PV [photovoltaic] penetration, and then how they've moved to that next stage.

So, looking at what other states do and their experiences is one way we think about how to address these issues in New Mexico.

But, no, we haven't made any decisions one way or the other, or even brought that type of discussion or that issue to the PRAC (Pricing Advisory Committee).

Sandia National laboratories continued.

Yes. ... I was looking at Hawaii's recent rate reform, that the public utility commission there approved, and the primary emphasis is on moving towards a default time-of-use rate where they're going to have pretty high ratio of the on peak in the evening hours, and then, really low [prices] in the middle of the day.

I think there was some mention also of extending a non-coincident peak demand charge to residential customers, but I don't think their decision included any fixed charges.

Sandia National Laboratories: Rate Case Filing

Given the changes taking place at the PRC, when is your anticipated decision on the rate case filing and pilot proposal?

PNM Response

We asked the commission to issue a final order in the rate case by December 1, 2023, and then rates would take effect shortly thereafter, January 1, 2024.

We have to walk a fine line here, because that is an ongoing proceeding with the PRC, and certainly subject to litigation. So, we can talk about it a little bit but there are going to be certain things, depending on when we get there that, we might just have to turn away and say that would have to be handled in the rate case venue.

InterWest Energy Alliance: Economic Development Opportunities

I [recall from a previous presentation] that PNM gets a lot of economic development inquiries that they turn away. How will your analysis and forecast take that into account? Do you plan to hold a public advisory meeting on this topic and identify how economic development opportunities may affect your forecast and needs?

Initial Response: PNM

We're not turning anybody away. We work with our economic development team very closely. And so does the pricing department. We work with them to figure out what proposals we can work with and what time frames we can work with.

Given the current state of the system, if a customer comes to us and they say, "We want to hook up 300 megawatts of load in 12 months," we're only a 2000-megawatt system and we don't have that much additional capacity. And trying to build a new generation facility that quickly is virtually impossible, especially with supply chain constraints and otherwise. We might say to them, "Well, what flexibility do you have on your time frame?"

We are doing our best to work with every single inquiry that comes to us, figure out how we can get them to come to the state if possible, and [determine] the time frame that they're working on. Typically, they're talking with us and many other service territories and it depends on what incentives there are--not necessarily just utility incentives--but if there are economic development incentives through different state agencies, city agencies, other IRPs, or other things that might be offered.

The electricity portion is usually one of the very small components that goes into decisions for customers wanting to site in a specific area, unless their overall cost for their process is dominated by electricity.

[Referring back to the initial question]

So, if we look at what we did in our 2020 IRP, it's a very similar process to what we're going to do here. In that 2020 IRP, we had a base load forecast and that's really what we wanted to have Itron present on today: Overall, what is the known forecast that we can surely count on? And so, Itron presented that sans the [rate 36 B customers (and that will be added into the forecast as well)].

Then, we're going to have multiple incremental economic development sensitivities that we're going to look at. And we'll have a range of those sensitivities that we'll run through our models and look to see what has to happen on the supply side in order to serve those customers, both from an RPS requirement for carbon intensity and carbon emissions free requirement.

Certainly, it's going to, depending on the amount, drive the needs for the load serving side as well, not just from the supply side, but also from substation, transmission line, distribution, all those types of upgrades, and those things that are really not considered necessarily within the IRP at this point.

So, we are going to have different economic development scenarios.

If the request is to have our economic development group come in and talk a little bit more about specifically what they're seeing from the development community, we can talk to them and see. But a lot of those conversations are highly confidential (governed by NDAs, et cetera). So, at a bare minimum, we can come back to this at a future meeting, and at least present the range of economic development scenarios we'll be looking at.

InterWest Energy Alliance continued.

Thank you for that answer. I completely understand the need to retain confidentiality on this. I'm not looking for a specific identification of companies or whatever--that's confidential.

But it seems to me that [PNM is] getting essentially besieged with economic development and expansion opportunities that you just couldn't cope with, or that the system couldn't handle. And it may be a timing issue. Maybe other issues. Could be all kinds of things, but it seems to me that this is an important factor for the state and for PNM. And if your current forecasts don't at least take into account that factor, then it's missing something.

And so, I'm wondering, how do you plan in your IRP to include that factor going forward, understanding that you've established for us how you look at the baseline today? But then adding onto the baseline, I think that's an important factor that many of us would be interested in knowing; how you plan to deal with that and having a range, let's say, would be useful.

We understand you can't identify particular projects or companies. but what are the ranges that you're looking at that may be realistic or high, medium, low, whatever?

It just seems like that factor is missing so far.

PNM continued.

I understand your point and it's not missing; it's something that we're going to include. We just didn't present that information here today. We were presenting the base forecast and the base scenarios.

I believe it was the [August] 25th presentation from our 2020 IRP, September 25, 2020 [link: August 25 presentation], right before we talked through Itron's slides, we showed how we were putting together some economic development scenarios. And in that IRP, I believe we had six different economic development scenarios set up. They were all incremental to the base forecast. We did analysis on them and presented those in the overall range of results.

We're going to do something very similar here. We're going to have a range of economic development scenarios that are going to be incremental to the baseline forecasts. Those loads are not going to be as weather sensitive, or to the degree that the residential customers or the commercial customer class are driving what Itron presented here today.

So, what we can do is take any one of those scenarios that Itron talked about earlier. Going back to some of Itron's slides [Slides 54-55], if we were to look at this matrix or correspondingly this chart [Annual System Energy Scenarios], any one of these, we could add economic development scenarios onto a low, mid, high, highly probable, or low likelihood.

But does it make sense to add them onto every one? Probably not. I don't know that adding economic, high economic development onto a low economy scenario would make sense. So, we're going be taking that into account when we put this together,

So, this is from the August 25, 2020, meeting from our last IRP [page 79, August 25 presentation].

This is kind of akin to what Itron was presenting today, where we start off with our base forecasts. But then here [page 80] we have each of these incremental economic development scenarios, and we're going to be doing something very similar. We can come back and present something like this. We're still working with the economic development group to try to put together what their thinking is--what's a low, a mid, a high, a highly likely scenario.

What we know about the queue right now for economic development is that if everything in the queue that we would want to bring the load onto the system for between now and 2025/2026 were to occur, it would double the size of our system. Pragmatically, it's impossible for us to add that much generating capacity, transmission capacity, distribution systems, substations, and all that to accommodate all that.

We know that not all of it's going to happen. I get your point.

The idea is, well, what can we do in order to maximize the potential to capture those loads? A lot of it's going to come down to what support we can get to go do things ahead of time because, if we go and do things ahead of time, we can court those customers that want to come in on very quick schedules.

But if we go and do things ahead of time, and those loads don't materialize, that means that the existing customers are going to be paying more because we've done additional investments expecting load to come that never materialized.

So, it's going to be a balance there of well, "What is it that your PNM customers, regulatory commission. or you as a stakeholder and others are willing to accept us doing: the "build it and they will come" approach versus just working with new customers and saying, "We've got to wait until you ink your load on the dotted line and then we can start making these necessary investments and securing enough capacity to serve you."

Right now, we just don't have the excess capacity that we can slide new loads into and serve them on day one if they are significant in size.

InterWest Energy Alliance continued.

Yes, I completely understand but the thing is if you don't ask the question of your customers, parties, the commission, you'll never get the answer and you'll never be able to move forward. So, I agree it's a question of do you take a "build it as they come" approach, which is kind of small ball, versus "build it and they will come."

In terms of what it is that you build to entice folks to come, I don't know what that is. I have no idea. I have no idea if it's more substations or whatever. I would leave that to you guys as experts, but it seems to me worthwhile to take a look at this as a key factor and to maybe ask your partners here, your collaborators, the question and pick the brains of your experts in terms of "Do we want to ask the question? What's the question? And what do we do with the answer?"

So, anyway, those are thoughts for you to consider and I think many of us would appreciate having a session on this issue. I think it would be useful.

PNM continued.

Well, appreciate that feedback and we can certainly make sure that we can present our economic development [ED] scenarios. We can have a more detailed discussion overall on ED and see what they can present in terms of the types of customers and things of that nature.

Just from what I know, they are getting many, many more requests now than they ever did. And those types of customers are demanding renewable and clean energy. They want to come in quicker than we've ever seen, be hooked up faster, and they're much, much larger. Given that we're a small system, the "build it and they will come" approach is really what we would need to do in order to court some of these customers on the time frame that they would want.

But it's not going to be a do one or the other or a third. It's going to be we have to make investments in the generation system, the transmission system, substations, distribution, all of that ahead of time, in order to make sure that we're ready when one of these large customers comes and says, "I want to be hooked up and serving my manufacturing process within 12 months."

And that can place a lot of risk on both parties. We definitely would like to have the discussion. I'm sure you're aware that we have an RFP that we issued back in the beginning of November for resources that would deliver in the 2026/2027/2028-time frame. We certainly could talk about that if there is support enough for us to ask the commission for some excess generation to enable some economic development, but that's only one of the things.

There are supply chain issues -- I know that our transmission department would tell us right now, if they need to go and get a high voltage transformer in order to interconnect a customer, and they have to order that transformer today, it is probably not going to be here for 18-24 months. If the customer wants to be hooked up in 12 months. even if we had the generating capacity, that's still a problem on the load-serving side.

So, there are a lot of things that are going on. I think that having the conversation is great, but it's a conversation that needs to happen in multiple different stakeholder venues other than just the IRP.

InterWest Energy Alliance continued.

That could be. I just think it is an important factor for the IRP as well.

PNM continued.

I agree with you.

Technical Session #11: February 15, 2023

NM AREA: Screening Scenarios

To make sure I'm understanding this right--this slide [Slide 11], which I think is helpful--what you're trying to do with Phase 1 is you got … a large set of scenarios, and you want to try to … weed out the ones that are fairly clearly not going to perform well, such that it really wouldn't be efficient to go on running against all futures.

So, if I understand right, what you're proposing to do on the screening is that it would be a more limited set of futures. Is that kind of what you're proposing to do, and basically run that first initial set of scenarios against the more limited set of futures to see what it produces and whether there's clearly some scenarios that are not worth pursuing because the economics, or what have you, aren't working?

Initial Response: PNM

Yes, that's exactly right.

What we have you can almost think of it like a funneling process, a screening process, some way of taking a large number of scenarios and trying to figure out if there are just ones that don't pass the sniff test. That's because of whatever characteristics, maybe it's very high-cost.

And the screen that we were thinking about--again, looking for feedback here, if others have ideas--is we would do two capacity optimization runs, both based on the current trends and policy future: one would just be the base future, and one would be that base future plus a significant amount of economic development load growth. And so, we would come up with two portfolios of resources with those capacity optimization runs.

Then, we would do our detailed production costing on both of those portfolios using the standard 50/50, weather normalized load forecast, which would be the basis for the capacity optimizations. And then also stress test it deterministically and [through] EnCompass with our 90/10 load forecast. So, we plug in a portfolio based on the 50/50 weather forecasts [and] run it against the 90/10 and see if that type of case gives us another piece of information as to how robust these portfolios are in adapting to different weather conditions.

And then, if we need to, we can also run it through [SERVM] as well. But that would give us a few data points to tell us, overall, on our base case, how did the cost [performance] look if we stress test them against an extreme weather case, how robust are these portfolios to changes in the load forecast? And then do the portfolios, or the types of resources included in the portfolio. Again, maybe it's a long duration storage project; does that resource potentially have an advantage over just general solar, wind, lithium storage, and enable economic development? And is that something that we would want to consider as a part of how robust the portfolios are, as well?

So, that's how we were thinking about it. And then, it could be that all the scenarios make their way through the screen, if they all are very competitive with each other. It could be there's a bright line that says, "Well, five of the 16 can be weeded out." And then we'll start moving the more competitive ones into the analysis with the rest of the futures.

NM AREA continued.

I guess two follow ups focusing on the last slide [slide 11]. [If I understand correctly], item 1, under the screen area, is the actual future, and item 2 is a sensitivity to that future.

Are you going to define what the current trends and policy future look like and the assumptions for that?

PNM continued.

We would be doing the current trends and policy future and then a sensitivity of that future with the high economic development or strong economic development assumptions. Then, do some additional testing on the production costs, both on the base load forecast, and then the extreme weather forecast, and we could drop that into SERVM as well.

Initially, we're thinking we would want to see just what the EnCompass results were.

We do have some slides later on to show the various assumptions for the different futures. The current trends and policy will be similar to what was looked at last time. It'll be your kind of mid load forecast, our mid gas prices, our mid CO2 prices, our mid technology curve.

So, all of the baseline assumptions, so to speak.

NM AREA: Long-term Storage

Does the company see this [Slide 14] more as something that the economics are showing has promise, or should be explored? Or do you foresee that there will be a reliability-based business case that really long-term storage of this nature might be necessary, or dispatchable resources in the alternative?

Initial Response: PNM

I think that all of the work that we've done, and the literature that can be reviewed, shows that in decarbonizing a system, one of the fundamental things that's going to be needed is some type of firm dispatchable resource, whether that's in the form of non-emitting fuel that you can put through a combustion turbine, whether that's long duration storage, or anything else. You could build up a lot of shorter duration storage and dispatch over a longer time period, but everything that we've been looking at says that long duration storage is something that's worth a good, detailed look.

Ultimately, the cost characteristics are going to be part of the decision-making process, We'll be examining that through the IRP and any subsequent RFPs. But from a reliability and resiliency standpoint, from just the overall way that the system needs to be in order to get truly decarbonized, having some type of firm dispatchable resource and long duration storage or something else is one of the fundamental tenets that we see as necessary to get us there.

NM AREA continued.

Yes, ... I see this with some other utilities, working as a stakeholder in [other] IRP process[es], they've been advocating something similar like this, whether in case that utility was combined cycle with carbon sequestration.

But I guess the key seems to be like I have seen, and I really liked to see. I would encourage the company to … more concretely demonstrate with analysis the need, or the steps and resources, if they believe they're needed. I think it would really help the process.

So, just want to provide that feedback.

PNM continued.

Definitely appreciate that.

E3 has done some pretty deep decarbonization studies that have always shown that a firm dispatchable resource is one of those things that enable decarbonization of the system.

If we look at our 2020 IRP, we compared just the ability to add on some hydrogen combustion turbines--I think 280 megawatts of hydrogen combustion turbines, displaced a combined 1500 megawatts of lithium storage and solar.

So, trying to figure out what you need and how much we're going to "overbuild" to decarbonize the system, if you don't have those types of firm dispatchable resources in the form of long duration storage or in some non-carbon emitting fuel, you have to have significant amounts of additional renewable and shorter duration storage resources put online.

[The IRP staff] has been working on an example that kind of shows some of the tradeoffs--really trying to get to carbon free, and what the requirements are. Just anecdotally--we do have some analyses on this--we think back to that resiliency study that PNM and E3 did, when we wanted to replace the 200 megawatts at Four Corners, we said, "Well, if you just do an LOLE basis, you could do it with 160 megawatts of gas, or it could have been 100 megawatts of solar, 100 megawatts of 4-hour storage, and 50 megawatts of 2-hour storage."

But then if you wanted to make it equivalent on an EUE basis, not just a frequency basis, but a measure of the amount of load not served, that 2- and 4-hour storage had to become 14-hour and 16-hour storage, in order to get the normalized levels of EUE the same.

[We did a presentation for NM RETA recently where] we did a little hypothetical example: What if you have a 100 megawatt, your high load factor load, and you want to serve that just with solar and storage, as you move up to 100% carbon free, and to do that 100 megawatt load, just on a solar and storage basis, you're going to need 405 megawatts of solar, 260 megawatts of 6.65 hour duration storage, because you're going to be charging that up over such a short time frame in the winter, and then discharging over 12- or 13-hour window in the longer time frame.

You start to get this tradeoff on charging times and the overall amount of energy you need stored on the system. So, longer duration could just be a pseudo way of saying, “Well, we need to make sure that we have a total amount of enough energy on our system to meet these requirements as well.”

And to do the resiliency piece of it, it's going to take a lot more than just the short duration stuff.

NM AREA continued.

And I do like the EUE approach looking at that because all LOLE results really have the same outcome.

PNM continued.

Yes, if you're only looking at the frequency, you're not looking at everything.

NM AREA Response

Thank you.

CCAE: New Demand Side Resources

Are you including identification of additional or new demand side resources like load shifting, time-of-use rates, interruptible rates, demand response programs, [and] energy efficiency as you identify the resource mix necessary to enable a carbon free system?

PNM Response

We are [doing something] similar to what we did in the last IRP. ... [in the December 15 meeting there was a lot of information on the energy efficiency modeling.]

We are taking the energy efficiency modeling that we did last time and trying to make some enhancements to it. But we're essentially modeling energy efficiency on the supply side where it's a selectable resource and the model can pick energy efficiency programs, depending on what the cost characteristics of its other choices are.

We are going to continue to model the DR [Demand Response] programs that we have. We have a time of use rate sensitivity load forecast that we'll be modeling.

In terms of additional demand response programs, in the last IRP, we did model extensions and expansions of the demand response programs. The toughest thing there is just making sure that we can always identify the type of program characteristics needed to enable that type of program.

What I mean by that is, if we make the DR programs too rigid, it's unlikely customers will sign up. If we make them too flexible, can we really count on them. And so, we've got to strike that balance.

But we are going to be looking at each one of those things that you've identified there in terms of time-of-use rates, demand response programs, energy efficiency, etc.

CCAE: Demand Side Resources in the RFI

This slide [Slide 15] refers to your RFI, Are any of the demand side resources part of the RFI?

PNM Response

We did not have any demand side resources offered into the RFI per se. There were a couple of software solutions that could make the aggregating of distribution level demand side resources more efficient. But the RFI did not come back with any specific demand side characteristics.

Onward Energy: Sensitivity Modeling

You indicated Valencia, that you would be doing sensitivity modeling. In what context? Are you going to be doing that through the IRP process? Is that something that's going to be included? I'd like to get a little more detail on what you mean by allowing that asset to retire or expire. and to allow a generic replacement to come in.

Initial Response: PNM

So, our base assumption is going to just be--this is why we've done it in all of our previous IRPs as well--that for any PPAs that come to term during the study horizon, our base assumption is going to be those expire and are replaced with whatever the economic choice of generic resources there would be at that point in time. And it's our intention to do the same thing with Valencia in this in this IRP.

Now, we were not anticipating doing any sensitivities around that. The 2026/2028 RFP could be utilized as something that would examine alternatives to Valencia in that time frame. So, it's a little unclear whether more detailed analysis through this IRP would be necessary, given there's an RFP that covers the time frame when the Valencia resource contract will come to term.

Onward Energy continued.

If I understand you correctly, are you indicating that there's currently two RFPs out there looking at that event horizon, to the 2026/2028 time period, but that in this IRP, you will not necessarily look at the sensitivities involving the expiration of the Valencia lease agreement?

PNM continued.

In this IRP, our base assumption is going to be that the PPA expires and will be replaced with whatever candidate resources are available in this specific scenario that we're looking at. There are many different scenarios.

There is an RFP that was issued in the beginning of November [2022] that spans the 2026/27/28-time frame. Those responses for the resources in the 2027/28-time frame are due today. And we will be doing the RFP evaluation for resources delivering in 2026/27/28 in parallel with this IRP.

So, to the extent we get to some case filings or other things that could work their way into the IRP, we will try to embed that information in there. But for this IRP, given that we already have that RFP out there, doing a lot of analysis around the sensitivities of Valencia just doesn't make sense.

Onward Energy Response

Got it. Thank you.

Member of the Public: Southern Resources

My question is kind of generic in nature. I was just wondering what you're going to do about those southern resources. Also, I understand [it], you really don't use much of the southern new resources in the northern part of your system. But you're going have to do something about those also, aren't you--relative to going to zero carbon sometime in this time frame?

Initial Response: PNM

Absolutely, we will. And you're exactly right, there is very limited transmission ability for us to bring power up from the south to north or deliver power south from the north.

So, they're almost, I would say, two independent systems. Of course, they're not completely independent of each other. But the majority of the load in the south has to be served from our southern resources; the majority of the load in the north has to be served from northern resources. And we will

have to take a look at what we need to do relative to those southern resources. In particular, the two combined cycle plants Afton and Luna that provide a lot of the energy for our southern loads, as we get close to that 2040 horizon, will have to be replaced with other technologies.

And so, we do have the model set up in a way where, when we're looking at the generic additions, we can identify, relative to the northern and southern parts of the system, where those generic conditions will be coming in and making sure that we are still able to serve both the southern and the northern loads. And we're not modeling as just a single point, but there are multiple bubbles and pipes connecting each of those things.

So, the focus of this particular IRP isn't going to get quite into the southern resources other than in a very generic way. As we move forward in time--I would say in that 2035-to-2040-time frame where a lot of those decisions on the southern gas fleet are going to have to be made, as well as on any of the residual gas assets up north.

But right now, we would anticipate the southern gas fleet continuing to operate, up until the time we need to be carbon free.

Member of the Public continued.

You also have the Luna station up north, which is relatively new. And then the second part of that question is: Is there any transmission possibility that might be an alternative to help get some of that southern resource up to the north in whatever timeframe that might be appropriate?

Is that any kind of an option that you would look at? Probably not through modeling, but through some other kind of analysis? I don't know what that would be.

What I'm trying to say is: Is there an option, a possibility of a reasonable option, for bringing some of that southern generation to the north by additional transmission?

PNM continued.

I'm not aware of any transmission that's currently being constructed or underway. We certainly are looking with our transmission group at different alternatives that would allow for better flows. So, I wouldn't say that anything is off the table at this point. But there are no specific studies going on that I'm aware of for new transmission to bring power from the south up to the north.

Member of the Public continued.

Is there any way of using displacement, like the Sun Zia line, or anything like that?

PNM continued.

Well, the Sun Zia line, as far as I know, is still going to be in the south. And even if it has resources that could be tapped, you'd have to build, because it's going to be a [HVDC] line. You'd have to have a converter station that would be added to the system to convert it back to AC power, and that would still be in the southern part of our service territory. So, there would still need to be some additional work done if we were to take any power off of that Sun Zia line to get it back up to the load zone in the north.

We'll have to take an examination of that as we find out more about the Sun Zia line and anything that would interconnect to deliver power across it.

Member of the Public continued.

My understanding is--probably wrong on this--that with Sun Zia you could have one DC line, and the other AC. They may have both. I don't know why they're doing that, but that's what I understand. So, that may be something you might want to consider.

PNM continued.

Yes, we're definitely keeping there all the options on the table. And if there was a way for us to take some power off the Sun Zia line and get it up to a load zone in a cost-effective way, we'll definitely consider that. Just right now, what we're seeing is that the additional transmission, to go from south to north, at least so far as what's been looked at, there's just not enough of a benefit as we sit here today. But that could change with the Sun Zia line or other alternatives that make themselves known.

Member of the Public: Operating Reserve Requirements

I ran across a recommendation about reviewing the reliability requirements for all the changes that are occurring, and considering inverter-based resources to maybe somehow be modified or the operation be modified to look at it and see if that can be used in response to operating reserves, which I think is going to impact, [that is] the change to renewables is certainly impacting the operating reserve and what you need to have.

I'll send that report to you if you haven't looked at it.

PNM Response

That'd be great, and I agree with you 100 percent.

The operating reserve requirements in the world of the heavy renewable system are going to need to be reexamined, and how the system is operated when it's dominated by inverter-based resources instead of spinning masses. It's still a challenge. I don't think anybody has the final answer yet, but we know we're told to go do it**.**

InterWest Energy Alliance: Accelerated versus Stable Forecast

I'm wondering, how realistic do you think this more accelerated forecast [Slide 16] is compared to the stable forecast? I mean, are you seeing inquiries that you think may actually hold water, that may come to fruition? That leads you to believe that an accelerated forecast may be what actually come to pass, and that's why you want to look at this kind of a scenario more seriously?

Initial Response: PNM

So right now, the way that I would respond to that is that right now, when we're getting inquiries, the inquiries are mainly from folks who want to come to this system sometime between today and 2026 or

2027. And so, when we think about much beyond that, it's really speculating on what level of sustained inquiries we're going to get.

I can't get too specific because these are mostly your confidential discussions that we have with potential customers. But, in the last couple of months, we've been providing a lot of information to some potential customers, and we don't know if they're going to end up coming here or not. One of them is 100 megawatts, and another one was between 100 and 300 megawatts, depending on what the design build out of their facility would be. Another one was a 300-megawatt customer.

We're seeing a lot of activity from very large customers that are interested in coming here. But the electric supply is one of many considerations that any potential new customer is going to consider when deciding to come here. So, the accelerated scenario here is that we just want to make sure we have an understanding of what it would take should something like this occur, Maybe it doesn't occur in such a linear trend. Maybe you get one or two 300 megawatt customers, and then you have a lull for a few years. And then another one comes in.

We definitely want to see what it might take to handle something like this because there is the potential to have a sustained amount of growth over a long period of time, and you will want to be ready for it.

InterWest Energy Alliance continued.

That makes sense. And it's likely to be fairly lumpy, right? I mean, I agree with you: You might get several companies that want to come on in a particular economic cycle, and then you might have a lull after that. So, the resources you bring on will likely be in chunks, right?

PNM continued.

Yes, the resources would likely be in chunks; the load would likely be in chunks.

Now, the load will have some type of ramp characteristic to it. Most of the time, when you bring a facility on, it's not going to go from zero to 100 megawatts overnight. But we have to have the resources on ahead of time to make sure we can serve them. The macroeconomic climate will determine a lot of it, too: how we're doing relative to neighboring systems, what tax incentives are out there--both at the state and the federal level, who knows. With what's in the IRA [Inflation Reduction Act], incentivizing

hydrogen production, you may see a boom of hydrogen production facilities; you may see a boom of more lithium facilities.

We don't know what's going to be, but we need to make sure that, whatever it is, we have an understanding of what it would take to be able to serve that load.

InterWest Energy Alliance continued.

Thank you. Appreciate it.

NMPRC: Generic Resources

Do the generic resources modeled have a location assigned with them? Due to the improbability of having any new transmission built to accommodate projects, I understand these generic resources to be placeholders. But is there an expectation that they are reasonable or possible that needs to be established?

Initial Response: PNM

With the generic resources, we are going to be modeling them with different geographical characteristics.

Through some of the recent RFPs that we've done, as well as some other data that we've gathered, we've got different cost estimates, say, for solar, that would be in the northwest versus solar that would be sited near to the load pocket versus solar that would be out to the west of Albuquerque.

So, we can come up with different cost forecasts, as well as we're looking at putting together different production profiles, based on their geographical locations. Then, we're modeling the system with different resources zones and transmission deliverability. And so, you will start out by saying, "Well, what is the transmission deliverability on the existing system?'" Then, we're going to have to have some assumptions in there about what incremental transmission would cost to deliver from some of these resources zones.

So, we're doing our best to try to get an idea of where the different resources would need to be sited. Now, there are limitations, of course, on what we can do in this type of modeling versus doing a fully nodal model, as well as using generic resources versus something that's actually built into an RFP. So, subsequent to the IRP, we could end up seeing RFPs that lead to very similar geographic sightings for resources. It could be that the average doesn't capture the low-cost resource in a given area and so you might see some differences as well.

Did that answer your question, or do you have any follow ups?

NMPRC continued.

Perfect. Thanks.

InterWest Energy Alliance: Solar in the Load Pocket

Why not include a Phase 1 scenario and base plus expanded solar, especially in the load pocket [Slide 17]?

Initial Response: PNM

I guess I'm not sure what you mean by that. We will be modeling different geographic locations, including the load pocket for different resources, including solar. And in the base technologies only, there will be the ability to add additional solar and storage--both in and out of the load pocket.

InterWest Energy Alliance continued.

I was just thinking I see you've got a base plus wind expansion--I think what you're trying to do there is focus on your transmission needs. So, it just seemed like you didn't have a similar category for expanded solar. But I think what you're saying is you're kind of lumping that into your base technology scenario. Right?

PNM continued.

So, let me dive more into some of the specifics here.

In the base technology scenario [Slide 18], we're going to talk about this as being mainly generic type resources because we already have the amended contracts for the things coming in 2023 and 2024. So, in the base technology scenario, we're going to be allowing new solar additions, beginning in 2026. And that can be in different geographic regions: it could be in the northwest part of the state, it could be out west, in western New Mexico, it could be in the load pocket, it could be down south. And there are different amounts of solar that could be added at any one of these locations for triggering potentially a proxy for some transmission investment that would need to happen in order to deliver you more than that amount of solar that would come on, or whatever resource it is.

Then the storage, we're also allowing that to start in 2026. The way we're going to do this storage modeling is that we're essentially going to be modeling for the generic battery storage, 4-hour variants that could be converted to 8-hour at some point, either right away so it could come on as an 8-hour battery, or it could come on as a 4-hour battery and then convert to an 8-hour battery at some point in time in the future.

So, those are the two main things that would be able to come into this base technology scenario prior to 2033.

And then we're going to allow in the base scenario new wind to come on in 2033 and beyond. The reason why we're picking 2033 is there's a lot of time to do transmission, of course, and we have the reduction in the carbon intensity requirement that occurs in 2032, going down to 200 pounds per megawatt hour. What we saw in our last IRP is that the generic wind additions, in 95% of the scenarios we looked at, occurred right at the same time as that decrease in the carbon intensity requirement because, essentially, when we get down to that 200 pounds per megawatt hour, we're having to decarbonize the non-solar hours and we've probably gone as far as we can with solar.

And so, we either need to build more solar and storage to timeshift that energy to help decarbonize the non-solar hours, or we're going to have to find a non-carbon emitting resource that can deliver in the absence of sun. That's kind of where the wind is coming in.

If we compare and contrast this against the base plus wind expansion scenario, in which we allow the wind to come in, say, by 2030, do we see a pretty big economic advantage of trying to accelerate investment in transmission and get access to new wind to help us decarbonize the non-solar hours in advance of the 2032 requirements? We thought the best way to do this was to make sure that we have a clear contrast between some base case that doesn't allow the wind to come in until after that requirement and something that happens before then.

So, that's where we are drawing the distinction there on the wind expansion pieces.

PNM Update

After some initial analysis, PNM has chosen to model generic storage as 4-hr storage only.

InterWest Energy Alliance: Least Cost Among All Bids

Does this exclude the “least cost among all of the bids” with reasonable transmission expansion scenario [Slide 18]? I just wonder if you are: A) overemphasizing the cost of the new transmission, the transmission plus wind scenario; and B) not allowing the market to bring forth the best local mix of all, which we cannot predict through the scenarios, [and] which I feel is somewhat too narrowly focused.

PNM Response

I guess I'm not sure what you mean by least cost among all of the bids, There are no bids--that's for an RFP. What we're doing here is looking at different RFI responses.

We've got a lot of ... information on generic resources. The computational complexity prevents us from throwing everything in the model, pressing "solve," and getting the perfectly optimal solution, given the limitations on technology and computing power at this point.

So, we do think that the way we're going about it, trying to look at these different scenarios, is going to help us get to a good mix of resources. And as we start to work through this year, we're certainly going to be working towards the most cost-effective portfolio.

If you have some ideas, and you want to throw them out there, we're happy to consider them.

In terms of the transmission costs, our transmission group had worked up a transmission cost estimate for a new line that would kind of run on a similar right of way to Western Spirit, to enable more wind to come in from the east. I think it was in the $500 to $600 million number and would take seven to 10 years to construct.

That's one of the reasons why we're taking a look specifically at this wind expansion scenario, trying to understand some of the benefits versus the costs associated with moving down that path.

SWEEP: New Resources at Retired Sites

Will the scenarios consider placing new resources at retired sites, like Four Corners or San Juan?

PNM Response

So, Four Corners ... if we are able to exit, say, in 2025 or 2027, that plant is still going to be operating. APS is the majority owner and so putting something at that site would be completely contingent on whatever the rest of the owners would want to do.

At San Juan, we will be modeling generic resources that could be in the northwestern part of the state, but we're not getting down to the level of detail to say that this is going to utilize the existing infrastructure or something like that.

When we look at specific siting requirements--that's done through an RFP evaluation, and if there are bids into an RFP that would have an interconnection point that would utilize some of the existing San Juan switchyard or bays--we would evaluate that through the RFP. For example, the San Juan solar project that's supposed to come on now in 2024, that was part of the original San Juan replacement portfolio; its point of interconnection is going to be into the San Juan switchyard.

New Mexico State University: Flow Battery Technology

Have you excluded the flow battery technology which was in the previous IRP?

Initial response: PNM

[This gets to a previous point that] it's not necessary to model every specific chemistry type or every specific model of a turbine or anything like that.

The flow batteries aren't quite as efficient--at least what we've seen in the round-trip efficiency data--compared to, say, lithium, but they are better than some of the other tech, other chemistries we've seen out there. We would hope to see flow batteries getting offered into some RFPs in the future and be able to compare and contrast the specific prices of those for specific projects against other technologies.

In this particular IRP, we're just going to be modeling for generic storage--those 4- and 8-hour variants of an 85% round trip efficiency storage devices.

We know that storage is going to be a big part of the system going forward, and we hope to see more of those chemistries getting offered into some RFPs in the future.

But no, we're not going to be modeling all of the different chemistry, so to speak.

PNM Update

The 2023 IRP will incorporate 4-hr 85% RTE storage, and 10-hr flow batteries with 60-70% RTE.

Synapse Energy for the New Mexico Attorney General: Hydrogen Fuel

What percent hydrogen fuel do you anticipate these new gas resources being converted to?

PNM Response

Post 2039, it's going to have to be 100%. hydrogen. For some of the earlier conversions, we still would be looking at what would it take to do 100% hydrogen power with natural gas likely as a backup fuel. We weren't considering really any specific blending ideas, mainly because blending hydrogen, while possible, due to the volumetric differences and heat content differences between hydrogen and natural gas, even if you did a 50/50 blend of hydrogen to natural gas volumetrically, that's only like a 20% reduction in the carbon--just due to the heat content of hydrogen versus natural gas.

So, when we're talking about hydrogen, we're typically talking about 100% hydrogen utilization sometime in a post-2030-time frame, or likely 2039-time frame, when we expect that the turbine manufacturers will have the majority of their turbans converted to the ability to handle 100% hydrogen.

InterWest Energy Alliance: Transparency on Least Cost/Least Risk Options

We are hoping the new rules provide more transparency about the least cost, least risk path options offered by the bids while protecting confidentiality because the projects available in the market are hard to predict.

PNM Response

I'm not sure if you're talking about the IRP rule or the procurement part about it for the RFP.

Certainly, when we get into the RFP evaluations, we have to protect the bidder data. But when we get into those case filings, of course, we've been making the data available on an anonymized basis. So, I guess we'll just have to see where we go from here.

In terms of the RFI responses, we did go through those in some previous presentations to give us an idea of what some of the projects out there might be. And, once we get to an RFP for those timeframes, we'll see what gets offered in.

NM AREA: Transmission Options

It sounds like, in these scenarios, the main one that would involve looking at transmission as part of it is the wind one. Is that pretty much right? Are there any others that you can see [where] having a transmission option as part of it would make a difference or would be useful?

PNM Response

The wind one will be the key one because the good wind resources are mainly in the eastern part of the state and would absolutely require new transmission to access. All of the analyses will have a transmission component built into them, either through a proxy transmission hurdle or the explicit modeling of the pipes and bubbles.

And so, we'll be taking a look at the transmission component in that sense.

But I just try to be a little bit wary of putting too many eggs in a pipe and bubble basket, when it's really the nodal models in the interconnection process that are going to govern what transmission is actually constructed.

Now, the wind one is a bit of an exception because we know for a fact, in order to get that wind, we're going to have to add new transmission, where with the other resources, you might be able to find some cheaper alternatives than building a totally new line kind of thing.

New Mexico State University: Hydrogen Fuel Cost Scenarios

Have you already covered the hydrogen fuel cost scenarios, or will it all come from electrolysis?

PNM Response

It's a combination of both. In the hydrogen scenario that I have on the screen here [Slide 23], that would be looking at electrolysis where we would be putting electrolysis, storage, and combustion equipment at a single site.

In the scenarios where we just would have gas projects converting in the 2040-time frame, that'll assume similar to what we did in the 2020 IRP: that there's some type of hydrogen economy that can deliver hydrogen at a set price. We'll be starting with some of the prices that we put together last time and having to work through making some adjustments to try to reflect what cost decreases we think are reasonable, given the new tax incentives that will be available to those producing hydrogen, probably with the price of natural gas as being the floor price, relative to hydrogen.

Member of the Public: Energy for Electrolysis

How do you treat the electric energy needed for electrolysis?

PNM Response

Within the model, it's a kind of an endogenous modeling of the power demands for the electrolysis. The power is then converted into hydrogen, which is then put into a storage tank, and then combusted back through a turbine.

So, we're modeling it from start to finish with the load requirements of the electrolysis, the storage volume that's considered within the storage device, and then the efficiency cycled through the turbine.

InterWest Energy Alliance: Transmission Expansion

My question follows up on [the question regarding the inclusion of transmission expansion].

[At Slide 22], I thought I heard you say that you were also going to look at, along with perhaps using the Luna and the other site that's in the south, north/south transmission capacity expansion as part of that. And that's completely understandable. I'm assuming that if you look at a base plus solar expansion, that you would similarly need to perhaps, depending on the geography, if you wanted to site solar, say, for example, in the south, where you might get better capacity factors and efficiencies and so on, you'd also need to look at transmission expansion on that north/south route.

I'm wondering, why not look at this more holistically, so that you're not just saying base plus carbon capture, and we'll lump all the transmission costs into that ... and then base plus solar, will lump all the transmission costs into that .... Why not look at it more holistically to see what benefits the north/south transmission expansion could provide you--with a diversity of resources, not just at your existing gas sites, but also add solar or a combination of things?

Initial Response: PNM

Fundamentally, what you're asking is, "Are we going to consider a north/south transmission expansion?"

InterWest Energy Alliance continued.

Yes, and I guess it sounds like you are, but you're kind of lumping it into these scenarios separately, instead of looking at it more holistically. So, I'm wondering, why not do it with a more holistic look at what the benefits would be Instead of lumping all the costs into one scenario versus another? It seems like that's kind of artificially narrow, in that the benefits would exceed just that simple scenario. They would be broader, so why not look at it more broadly?

PNM continued.

It gets back to the computational question--the computers and the models out there. You're just not capable of simultaneously putting everything in and optimizing and coming up with the magic answer.

Any transmission analysis that's done here--and we tried to make sure that the folks understood that from the transmission presentations--is not what's going to drive transmission investment. The IRP is just not where that's going to happen. We can take a look generally at some transmission-related things and see, at a very high level, what benefits there might be, but until you're doing your actual nodal production cost modeling, load flow studies, and other such things, you're not going to be doing anything that's really going to drive transmission investment.

And then there's a separate process for that [we've presented on previously] And there's a separate stakeholder process. There's a separate application process, of course.

So, the primary focus of what we're going to be doing with the IRP is trying to look at the different generation, storage, supply, demand-side alternatives. We'll do our best to capture some of these transmission pieces of it.

I know that you brought up PacifiCorp as an example, so to speak. PacifiCorp's IRP, while they do some endogenous transmission modeling, is not where their transmission investment flows out of. It just gives you a little bit of idea of trying to understand some of the interactive effects for resources, but, at the end of the day, the transmission is going be done in a completely different realm, with a completely different analysis that's going to drive those investments.

We certainly can take a look at, if we were to do a scenario where we put a north/south line in there for free and look at a difference [in NPV] on that without having that line in there and how the power flows might change a little bit.

But, at the end of the day, until we actually have a transmission study done that can actually determine what that line characteristic would be--and we're going to continue to operate those southern gas plants up until we actually have to take them off the system--serving that southern load really is going to be fundamental to those southern gas plants.

So, I get what you're saying. I know that, in an ideal world, we put everything in one model, we press a button, and we get the magic answer. Unfortunately, that's not where we're at today. And the value of doing transmission modeling with pipes and bubbles in an IRP is very, very limited. Transmission analysis really needs to follow very specific siting of resources, terminal and start points of lines, nodal production costing, power flow analysis, and other things that are just well beyond what can be considered in a 20-year IRP.

InterWest Energy Alliance continued.

Yes, I understand. I know we've gone through this before. It just seems more and more obvious as you go through these scenarios now that transmission constraints are becoming more and more of a sizeable factor in your consideration of generation and storage resources in the IRP. So. essentially saying you can't deal with them in the IRP just raises questions about the validity of your analysis then if you're not able to cope with one of these large factors.

That's not a question. It's just a frustration, I guess.

PNM continued.

Yes, I appreciate the perspective but, again, I think if you look at virtually any utility out there and the way they're doing IRP, transmission is just not a factor in the IRPs--at least you're not doing IRP as the basis for justifying transmission investments. That's really a different process.

And I think the industry understands that we need to move in that direction. We've got the Encompass nodal model. We brought in our transmission group, which is working on putting together a better network representation. We're hoping by the time we get to the 2026 IRP that we'll have a better solution.

But as we sit here today, the tools that are available to us, and the amount of information that you can get from a pipe and bubble model relative to transmission, just isn't the level of detail that you need in order to say we need to invest in transmission. The best it could do is say, "This looks promising. And let's go study it further."

InterWest Energy Alliance continued.

Let me just ask, [regarding the base plus wind expansion scenario on Slide 21]. Here, presumably, it sounds like you recognize in this scenario that you need to add transmission in order to unlock the wind expansion. I think that it seems like you're saying here that you can do that for wind. Why can't you do that for solar?

PNM continued.

The wind you can almost think of as a radial line that you need to go out there, even a large gen tie to go out and capture that wind. There's no more way to bring wind into the load center without adding some transmission. Our transmission group did some analysis on what the cost of an additional line would be.

And in terms of actually modeling that, we don't have to model the transmission line itself if we don't want to because it's essentially just taking the wind out and saying that you're going to add enough

transmission for such a cost that you can deliver it all to load. And if you think about it like a radial line with nothing else that would be going onto it, it's a very simple way of trying to capture both of those pieces.

We're talking about adding things in and around the load zone or at other points on the system. We can get some general ideas for what the transmission system or others can handle from solar. But there are lots of different points where we can put solar on the system. There are lots of different places where you can interconnect. There are lots of different transmission solutions that could be done to try to allow better connections or better flows of things. And if any one of those assumptions is a little bit off, the outputs are going to be a little bit off as well.

So, if the RFP comes in with a price for solar in the northwest, that's 10% cheaper than what we're modeling here, but if the cost of the transmission is 5% more, you may end up seeing that the better solution is to do something somewhere else. That's why the idea of trying to do pipe and bubble transmission modeling can give you a little bit of insight into some high level scenarios, just like this one here: This type of wind scenario lends itself well to being able to say, "Well, even if I don't put a cost for the transmission element in there, if I could deliver, say, 800 megawatts of new wind, and I assume the transmission is even free, on a net present value basis, what's the cost differential between that and my base case scenario, and is that enough to justify potentially investing in the transmission?"

Then, maybe it says, "It's worth looking at more." We still then have to go to the transmission group. They're going to have to determine what the actual type of conductor is, what the actual line route is going to be, update their cost, figure out time frame, go through the full transmission study process. So, at best, this is just going to be a tool to say, "We should study this more." It's not going to say, "Go and build this line."

InterWest Energy Alliance continued.

I completely understand. But I guess the question I'm asking is that it seems like you're depriving yourselves and all of us with the same analysis, kind of analysis, with respect to a known transmission constraint north/south.

And as we all know, the solar resources in the south are very good. And you also have two gas plants there that you're looking at potentially converting to hydrogen, or something. It just seems to me that you're depriving yourself and us of looking at the benefits of doing that holistically by addressing the transmission constraint; that's a known constraint.

So, again, I understand your answer, but I just think you are missing a big chunk of what you could be doing here.

PNM continued.

Okay, I appreciate the perspective. We can talk about a way to put in an expanded north/south line and see how that might change the production cost of the system. And is that a change with production costs of the system, on the net present value basis, get us to a point where I would say it warrants a new study from the transmission side of the house.

The difficulty there is still going to be that with a pipe and bubble model, you're not adequately capturing what the actual power flows are going to be because the pipe and bubble does not enforce the physics of the way the impedances on the system work.

And so, we can put some effort into that. We can do a free north/south line and we can see what the net present value difference is. I suspect that the solar resources in the south are not so much better that they're going to justify a transmission line of that cost or magnitude, especially when the natural gas plants down there reasonably don't need to come out of the portfolio until the late 2030s. And so, you're continuing to operate those with the transmission limitations that we have versus spending money on a new transmission line that isn't potentially needed right away.

We'll take a look at it. We can try to do that. It's just that I don't think that you're going to get the level of certainty coming out of that analysis that you're hoping for.

InterWest Energy Alliance continued.

Thanks. I appreciate you agreeing to take a look at it. Nothing that comes out of this is going to be completely definitive because you will have RFPs, and so on. So, if what comes out of this is the identification of the need to study transmission constraints north/south or elsewhere, I think that's a good thing. It's a step in the right direction.

PNM continued.

I would encourage you also to attend the stakeholders group for the transmission piece because that's really where that analysis should be done--the north/south kind of studies would be better suited in a transmission point of view.

Member of the Public: Source of Electricity for Electrolysis

What is the source of electricity for electrolysis--on site solar or wind?

PNM Response

It's really just going to be whatever power is on the system. We would assume that the electrolysis is grid connected, which would essentially just consume power from the grid. What we've seen in the modeling that we've done is that it very much coincides with periods when there is excess solar on the system, but there's not going to be a requirement that it's got to be coupled with, say, behind-the-meter renewables for the electrolysis.

Technical Session #12: March 15, 2023

New Mexico State University: Flexibility Cost

I have a question about the sensitivity study on the flexibility needed in this model in the study.

Because the flexibility can be at two different time scales, like real time balancing, load following, using reserve, longer time scale could be diurnal energy storage and seasonal energy storage to mitigate energy deficit. If you decarbonize the system, some studies say that the ancillary service and flexibility could be much more expensive.

Does the study, the scientific study, reflect the flexibility cost, including the real time operational cost and the capacity requirement cost up to capacity procurement cost in this analysis?

PNM Response

[I understand that] MISO does have an organized market structure for capacity requirements, ancillary service requirements. That is not the case for PNM as a vertically integrated utility that operates its own balancing area authority.

So, we are not modeling those as market functions. We're modeling those as requirements of our system through, “What are our operational reserve requirements?” “What are our contingency reserve requirements?” When we do our loss of load probability modeling, we're dispatching down to a five-minute level. So, we're getting anything that could be missed due to flexibility violations and things like that. And those will be captured within the overall investment and operational financial metrics that come out of the modeling. But it's not an organized market structure in a sense where we're putting in input prices on those components.

SWEEP: Demand Response Futures & BTM PV Forecast

I just had a question mostly on ... [Slides 20 and 21] How would different demand response futures be considered? Are we looking at it as a resource that could be competing against typical supply side? Or is this more of a key assumption like a forecasted modifier?

PNM Response

Similar to what we did in 2020 IRP, energy efficiency and demand response resources will be modeled as selectable alternatives and compete against supply side alternatives on a cost basis.

SWEEP continued.

Okay, That's good.

And then for the behind the meter [BTM] PV [photovoltaic] forecast, is there a battery component to that as well?

PNM continued.

The behind the meter PV forecast is specifically just a PV piece right now. We've been discussing internally, as one of the cases we might look at as well if we wanted to put batteries there. It probably requires a DRM system and allowing it to dispatch on behalf of the overall utility benefit, not just trying to allow individual customers to optimize the operations against their own tariff. We're thinking about the way that we might look at that.

I think that's something that would be an interesting topic for the modeling subgroup, but that is something we've been considering. Yes.

SWEEP continued.

Okay, so it sounds like through the modeling subgroup there can be a discussion about how the different components in your grid modernization case might augment these assumptions.

PNM continued.

I don't know that I'd say they would augment the assumptions here on the screen [Slide 21].

These are all individual inputs that have been developed and then put in. If we're talking, hypothetically speaking, let's say it like this: What if we had an incentivized program that would allow customers to get a rebate or discount on their rate structure if they were to put a battery at their house along with their behind the meter photovoltaic, but allow the dispatch of that battery be optimized by the utility? What are the things that would be required to do that?

Then we would need to have a DRMs-type platform. We would need to have the advanced metering infrastructure in place. Assuming those costs are accounted for, and we have this programming, what would the adoption rate of that program be? So, we have to decide what the sizing constituents of that are, how many batteries might be able to be stalled year over year. But then allowing that to be a resource that can be aggregated up at the bulk transmission level, dispatched against our load, and as an offset to what other supply side resources might need to be added by the utility.

Maybe we can look at an NPV delta then a VAT against your base case and say, “Well how much does that save?” And then, “Does that then give us some numbers on ways we might be able to look at what type of incentives could we offer in order to make that program a reality?”

New Mexico State University: Hydrogen Prices

I just wanted to bring up your answer to my question about hydrogen prices. Was it that you're tracking hydrogen prices as gas prices? So, it seems like the gas price does continue to be relevant.

PNM Response

For the hydrogen price, we might say there's a floor on the price of hydrogen that equals the natural gas price forecast, but the hydrogen price we'll be looking at a couple of different ways.

One would assume in a hydrogen economy that you just kind of have a delivered product. The other would be self-producing the hydrogen. But those would be all influenced now by the production tax credits available and investment tax credits available for hydrogen production storage and equipment through the IRA [Inflation Reduction Act].

So, we would have a very separate and distinct pricing for hydrogen. Maybe it's a good idea to think about doing a low, a mid, and a high there. But the hydrogen price was something that we were going to endogenously develop through the modeling, specifically, of electrolysis storage and conversion to electricity within the model, as well as looking at the potential forecast for an assumed delivery price of hydrogen but trying to capture the effects of the IRA tax credits on that were not available during our last IRP.

NM AREA: Sensitivities and Core Futures

I look at this IRP sensitivities [Slide 22], and you go from left to right, with the changes on the various assumptions, and I'm trying to compare this to the IRP core futures. It seems like you've got more categories, from left to right on the slide you’ve got up right now versus what you have from top to bottom, on the slide before on core futures [Slide 21]. I'm wondering, is there a version of this RFP

sensitivity slide that can be made that essentially lays out the four core futures at the top of it, or something, just so that it's easy to see how the four core futures compare under all of the things from left to right versus the sensitivities?

Initial Response: PNM

We could think about doing that. The previous slide [Slide 21] identifies, for example, in the current trends in policy, we've got our load forecast assumption, and that would tie to here. We didn't list the mid load forecast because that's not a sensitivity. Everything's always the sensitivity around the mid.

So, yes, let me think about how we might be able to do that.

We're saying that here's the core case for current trends and policy. And then, if you wanted to go to one of these components, and do a sensitivity to that, you would go to this next slide [Slide 22] and say, “Okay, well, if I want to go to the [EV?] adoption forecast, instead of using mid, what are my choices?” Well, EV adoption falls under the behind the meter; it's a customer behavior, so I could go with a high or a low.

NM AREA continued.

Yes, I guess what was kind of throwing me a little is that the sensitivities, the way you're presenting them, are not just a modification to one or two things on one of the four core futures; but rather, they're almost a way, at least they're striking me--maybe I'm misunderstanding--almost like as independent futures that are defined.

PNM continued.

I see what you’re saying. That's a bit confusing.

No, these are only meant to be a change to a single thing. So, let's say that we would look at what's highlighted in a given color or bolded is the change. it's not affecting anything else would be the way to

NM AREA continued.

Are they all essentially all sensitivities to current trends and policy? Would that be fair to say? Am I getting that right?

PNM continued.

They're all sensitivity factors to the reference pieces and current trends and policy, yes, but the bolded (colored either in black, red, or green) is showing what's changing. And it's just trying to categorize the change both across the top and going down the left-hand side.

I see that's confusing. Let's think about a way to modify this. But each of these only represents a single change to the given factor.

NM AREA continued.

And I did notice that I think you guys did a good job putting this first stuff together. I'm not seeing things obviously missing. I do wonder how you want to work the feedback, assumingly, when we ultimately may have nothing we think is missing or needs to be added or is unnecessary on this list. But what do you perceive as a feedback process, given we also look into the facilitator process or really transitioning to that?

PNM continued.

We've always been asking for as much feedback as possible sent into our IRP website or email. At this point. I think it can go through [PNM] or [Gridworks]. And if there's the ability to scan it and mark it up and annotate and say here's what we think is wrong or missing and send it back in. Or you can provide us just a verbal feedback at a meeting or working group. And I think there's multiple opportunities or ways to provide that feedback.

NM AREA continued.

Okay, so you're not setting any hard deadline or anything on this yet, at this point.

Gridworks continued.

I would suggest you keep track of any notes of things you think need to be considered, or if it's good as is, and then when we have the facilitated conversation on this, it could be even as early as the main workshop.

Two things.

One, keep track of any of your thoughts because we'll probably start out the conversation with the great work that PNM has already done because they've incorporated much of the feedback that you've heard already from the public advisory process. There may be some new things to consider. So, start from this.

Then, we'll hear your comments through the facilitated stakeholder process.

I'd say keep track of any of the thoughts that you have on the material presented to date. And, if you have the opportunity to compare those notes with any of the other stakeholders, when we all come together, we'll know if there's strong support from lots of the group or nobody in the group.

You're welcome to do that offline. But I'd say keep track of your comments, and we'll incorporate them when we get together later in the process.

PNM continued.

And I would say the impetus is on feedback on certain things sooner rather than later, because, if you're thinking that we're missing something that has to be developed, that takes time, and we have a hard deadline when we need to file the IRP.

So, we've been asking for feedback over the preceding 14 months, trying to figure out if there's additional load forecasting errors that folks want to develop. Nobody spoke up, just as an example. And so, given the time constraints, there may be things that just are incapable of being done.

NM AREA continued.

That's a fair warning. And thanks [Gridworks] for your comments as well.

SWEEP: Energy Efficiency Technology Bundles

Are the energy efficiency technology bundles documented in a prior slide deck?

PNM Response

Yes, the energy efficiency technology bundles were discussed in our January [2023] meeting.

I don't think we were looking for a lot of feedback on the development of those bundles. Those are one of those things, at this point, it's going to be tough to change. If there are things on here you want to get together and discuss or provide some feedback on quickly, we can talk to AEG, which we worked with on the development of those bundles for the energy efficiency bundles. But if you're trying to go back and rework those, depending on what the changes might be, it would be a difficult thing at this point.

So, we should probably take an action item on that to get to get you that material.

Reliability-Resilience-Resource Adequacy

Kickoff Meeting: April 28, 2022

Member of the Public: 18% Reserve Margin

When do you plan to file the 18% planning reserve margin, if you have not already?

Initial Response: PNM

We mentioned the 18% reserve margin in the 2020 IRP and then the portfolio we forwarded in our Palo Verde filing included resources to take us up to that 18% level, which the [Public Regulation] Commission approved.

That is likely to be just the first step. We're going to have to continue to increase the amount of reserves on the system as we take more and more steps towards a carbon-free system.

Depending on what you do with distributed resources and how that may interact with a more dynamic system, we'll have to figure out exactly what those numbers are. But just going, for example, from 18% was calibrated to .2 LOLE [Loss of Load Expectation]. If you go to .1, that 18% goes up to 21%. If you start to think about these other reliability metrics, like unserved energy or other things, you may find there is a tradeoff between what the planning reserve margin number is and whether that actually meets a different reliability metric, depending on how it was calibrated.

Member of the Public: Other Studies Underway

What other studies, in addition to the Southwest Resource Adequacy Study and the PNM Resiliency Study, are underway now?

PNM Response

Those two studies have been completed, but we'll be doing a second phase of the resiliency case study. We are deciding how to incorporate other topics into this IRP. There are implications, key takeaways, coming out of the first two studies that are helping to inform how we might want to look at other ideas.

CCAE: Effects of Increasing Decarbonization

Please clarify what you mean when you say, as the system moves toward more decarbonization technologies, PNM wants the system to act the same. It's my understanding that these newer technologies inherently require a system that acts differently, maybe more nimbly, and utilizes energy sources in a different way.

PNM Response

That comment referred to our thinking about the way we would plan a system for reliability purposes, for resource adequacy purposes, if the traditional metric that is used is loss of load expectation and we are designing a system to meet a loss of load expectation metric, say, .1 or one day in 10 years expectation of a loss of load event.

Now, with a traditional system that had dispatchable resources, if an event were to occur, meaning if there wasn't enough supply to meet your demands, and you had to enter a load shed event, there would be associated with that event the amount of expected energy not served, the amount of peak capacity or a peak demand that was not able to be served--things of that nature that you can't tell from only looking at the loss of load frequency measure.

The question to the group was, ‘If we're looking at designing a carbon-free system, would you expect the system to behave in the same way from a reliability or resource adequacy perspective, resiliency perspective, as the more traditional system?’

So, if the probability of having a load shed event is the same for a traditional system and a deeply decarbonized system, would we be willing to allow, for the sake of the deeply decarbonized system if it occurs, the magnitude to be worse?

That's the question that will be posited in the next stakeholder meeting, where we dive into the recent resiliency study, which revealed some very interesting things concerning a traditional system versus a decarbonizing system. For example, if we design to just a loss of load frequency standard, the way the system would behave, should an event occur, can be very, very different.

E3 Study, Resource Adequacy in the Desert Southwest

May 25, 2022 Public Advisory Meeting materials

Member of the Public: Contingency Reserve versus Planning Reserve

Will you do any kind of analysis regarding the contingency reserves rather than just the planning reserves?

Initial Response: PNM

The contingency reserve requirements are set by WECC and NERC, and then we have some reserves and sharing agreements. We will be monitoring those to determine if we think the reserves currently on the system can handle the disturbances.

We are also partnering with Sandia National Laboratories. They recently finished a report. looking at operating reserves and trying to come up with a way of formulaically determining the right amount of operating reserves for a system as we have more and more renewable resources and energy storage. It's just a first pass but we understand it's a very big problem. And we're very encouraged that Sandia wants to work with us on this and there are a number of other projects we're working on with them. We recognize that the static reserve issue is something that will need to be looked at in a more dynamic fashion.

Sandia National Laboratories continued.

In working on this study and speaking with PNM, we both felt it was important to think about the kind of variability that will be on the system in just a few years as the PNM system goes from about 330 or so megawatts of utility scale PV now to 1500 or so and in just two or three years. It's quite an incredible change for the system in such a short time.

So, because the level of solar is so low, comparatively, right now, there isn't a lot of experience with how much variability that is going to be in the system. We really wanted to look at what kind of variability the system may see in a few years, and how much in the way of reserves might need to be set aside to deal with the solar variability. That can be handled by batteries, it could be handled by gas turbines, but there will be the need to set aside some amount of capacity to deal with that variability.

PNM continued.

We are working with Sandia on a number of projects. Maybe they can talk about some of those projects at a future meeting. We're excited with our partnership--literally in our backyard, just down the road. Our work with them goes on behind the scenes. We appreciate all the work that they're doing with us and the insights they provide.

Member of the Public: Extreme Weather Events

Can the system be more robust in an extreme weather event?

PNM Response (pulled from the identical question asked in Grid Modernization)

The specific concern raised about the 2020 IRP was that some thought that the load forecast by the time we got out to 2040 was wrong. We had a lot of different load forecast scenarios. Granted, the further out in time you go, the more uncertain forecasts are. We think we're using industry best standard practices for load forecasting, but we can have a conversation about it.

We are scheduling a technical session with PNM's load forecasting group to discuss all the parameters, and, if there's a different load forecast scenario that needs to be considered, we can have them generate one and run it through the portfolio model.

Another topic that was raised in 2020 was renewable resource cost development. Perhaps folks didn't understand exactly how we develop renewable resource cost assumptions. We can go through in detail what we did and if there are alternative methods. Something else might be more appropriate, so let's figure that out.

And the same thing would go for the other candidate: resource technologies. We recently issued two requests for information (RFIs). We did one very similar to what we did at the outset of the last planning cycle, where we were asking for new and emerging technologies to look at things that would help us to decarbonize the system. There are no limits on whether it has to be a utility or supply side resource or demand, right demand side resource, or distributed energy resource. We're hoping to see the whole kit and caboodle in terms of the amount of information that we receive.

We also recognize that there are some technologies that take a long time to develop. In the last planning cycle, there were two or three long duration storage projects that typically take five to 10 years or longer to be developed. And so, we put out a second RFI to try to get more specific information about not just general technologies, but also specific projects that may have long lead times. The RFIs are due June 15 and respondents' updates by September 15.

The deadlines for the RFIs correspond to when we want to bring the responses back to our stakeholders to discuss these different technologies and resources, and how we can incorporate them into our modeling protocols, making sure that we have the ability to run them as resources for load serving requirements in our model when we start doing the full scenario analyses in the September-October timeframe.

The long duration storage RFI and also hydrogen resource modeling were some issues that raised in the 2020 IRP comments, so we'll want to discuss those. We've been doing some additional testing and modeling -- R&D -- within our own groups. We can talk about that as well as general ways these things are modeled if there are other assumptions about them. For example, one question was about how much water does it take to make hydrogen and does PNM have access to that kind of water.

Distributed resource modeling is on our list for discussion as well. We want to make sure we talk about that as much as we can but, again, that one gets a little bit tricky because the IRP is at the bulk system level, not at the individual feeder level. But we do have to make sure we can figure out how we account for all of those DRs when we are designing a least cost plan.

Regarding scenario tree development, I was explicitly thinking about the Four Corners Power Plant Thinking about the different scenarios and sensitivities that we're going to need to run, how are we going to model the existing resources? What were we doing with our existing resources? Is that the best use of them or the most appropriate way to consider the existing system?

Presentation: May 25, 2022

E3 (Energy + Environmental Economics)
"Resource Adequacy in the Desert Southwest"

InterWest Energy Alliance: Batteries – Longer-Term

Was your assumption in this study a 4-hour battery? And if not, why? And if it was lower than that, why?

What are you seeing on the horizon in terms of the likelihood of reasonable technology for a longer-term battery in the future?

PNM Response

Slide 48 shows the constituents of the portfolios, each of which we put through our standard resource adequacy framework that was designed to meet the 0.2 LOLE [Loss of Load Expectation] standard. Now we're moving to .1 in this next planning cycle. But we already had our IRP model set up, designed for 0.2 LOLE or one day in five years.

We designed these portfolios to let our resource planning software choose between different types of resources to meet the given resource adequacy metric and replace the 200 megawatts of Four Corners with a few different types of portfolios. So, for Four Corners, no new combustion portfolio was 96 megawatts of solar, 108 megawatts of 4-hour battery, and 48 megawatts of 2-hour battery. That was what the model selected as the economic portfolio, the least cost portfolio under the no new combustion framework. So, no new gas resources or combustible resources were allowed.

That would meet that one day in five standard and a similar look was done for the other portfolios. One of them is all gas and the other two are a mixture of a little bit of gas, a little bit of renewable, and a little bit of storage. We designed these four potential replacement portfolios--and these are generic resources. They weren't based off of an RFP. So, it's really the same idea of the IRP type framework, but they were designed to meet that set, resource adequacy standard.

And then we jumped into this resiliency framework and tested each of those portfolios for those different scenarios we described.

We're exploring a number of different things [for the longer-term battery]. Similar to the last planning cycle, we've issued an RFI to look at new technology that could help us meet our carbon reduction goals. Along with that, we actually issued a second RFI to look at any potential long duration storage that might have long lead times, which would be deliverable in the 2028-2033 timeframe. The first round of responses is due back June 15. Follow ups are due through September.

We are always talking to other vendors as well. We know there are other longer-duration storage technologies out there, many of them still in pilot phases. In an early stage, you can add additional duration, of course, to lithium batteries, and you end up asking if it is really a question of duration. Or should it be a question of total value? And because you can increase the total capacity for the same volume—forget equivalent duration—you'd have the ability to utilize, say, a 4-hour 100-megawatt battery; if you had an equivalent 200-megawatt 2-hour battery, the total value of stored energy is the

same. And you could run it on a discharge. Just like a 100-megawatt 4-hour battery, you could run it like a 50-megawatt 8-hour battery; it gives you some flexibility, as well as allows you to increase the charge rate.

So, there might be times in the wintertime, where your excess solar production is constrained to a narrow set of hours due to the shorter daylight hours, in the summers, you might want to look at doing increased size on the charging piece as well.

There are a lot of different ways to tackle this problem, and we're exploring them all, including one of the specific questions teased up for a phase two type study: How should we be looking at the problem? Is it strictly duration? Is it really volume? because you want to take into context what the charge and discharge rates could be, as, again, you can have a 2-hour battery that's the same as a 4-hour battery--just charged, discharging at a lesser rate?

We're going to do more presentations on batteries.

Once the RFI results are in, we'll hopefully have, like last time, multiple different technologies to look at: pumped hydro flow, batteries, maybe iron, air core batteries, lithium, gravitational storage, and a number of other different types of storage.

We visualize the future system as having a number of different pieces to it. You're going to have to have distributed resources. You're going to have to have long-duration storage. We have to have short-duration storage. Some of it is going to have to be at the renewable resource sites themselves. Other pieces will have to be in the load pocket so you can maximize the efficiency that transits the transmission system. There is just a whole lot that we still need to figure out, and we're still in the early stages.

This work is very important because it's giving us ways to analyze some of the issues and the right questions to ask.

Member of the Public: Batteries

Have you thought about what market structure would make the conservative use of the battery versus the sort of straightforward arbitrage use more likely or profitable?

Initial Response: E3

Most of our reliability analysis has been done more for the utility. What we're talking about here is potentially only a handful of days a year, so the battery could run an economic arbitrage mode for the majority of the year. But then it's just being more conservative for just a handful of hours.

PNM continued.

PNM being a vertically integrated utility that does not participate in an RTO [Regional Transmission Organization]. We are a member of the [Western] EIM [Energy Imbalance Market], but it doesn't give you any type of resource adequacy attributes; you've got to carry your own weight when you go into our market. We focused this study on how we would start to improve resiliency and reliability in that context.

This is a great question to add for stakeholders going into phase two of this study: What are some of the next steps we would want, and how can we incentivize? That type of behavior would certainly be one of them.

From PNM's perspective, it's a matter of how we design the battery algorithms and control systems and ensure that, if you're in a typical operating zone, they can be dispatched for economic arbitrage or other products. But, given the state of the system, if you get outside of that operating zone, and given all the forecasts and other things that would be coming into a real-time control system, there would be a switch essentially that would move that battery from being unable to do the arbitrage opportunities to instead being conserved for reliability operations, especially for these extreme weather events.

You might have the ability to see those extreme weather events coming, but even if you get a weather forecast, you might not know how bad it's going to be. Again, from PNM's perspective, not participating in a market yet, if you start to see the problem manifest a couple of days ahead of time, you'd get those batteries charged up, but you just don't release them because you might need to rely on them for some significant event over the next couple of days.

E3 continued.

From the market's perspective, the question relates a little to the topic of capacity, accreditation in general, and the obligations that come along with receiving capacity credits, whether through a bilateral resource adequacy program or an organized capacity market in a centralized construct. Normally, what will happen is that when you sign up to provide capacity towards a resource adequacy requirement, which will come along with some sort of market obligations, as well as potential penalties or incentives for performance during specific periods.

So, perhaps we should think about how, in addition to responding to the natural price signals of the energy market, we might provide the right incentives or sort of signals to the storage resources to be there when we need them most, even if it means forgoing some amount of opportunity and energy arbitrage.

PNM continued.

Along those lines, maybe it's something that relates to an energy limited resource, especially a short-duration resource, the capacity, and payment structures through markets that need to be based on state of charge and occur more frequently throughout the day or week, as opposed to having a monthly kW month or annual capacity payment that would be more attributable to resources that have infinite duration and supply.

Member of the Public: Hardening of Generating Facilities

Did you assume in the scenarios any changes to the hardening of any of the facilities for either extreme heat or extreme cold?

PNM Response

In 2011, we learned a lot, and PNM has been going through a number of winterization and hardening operations for its existing system. That's one of the reasons the system performed very well during the 2021 winter event.

The study did look at what happened if the system wasn't hard, and if there was either, common mode type failures or “extreme cold weather correlated forced outages.” We did look at that as one of the sensitivity cases, where we assume that some of the new resources that were coming on would already have that type of weatherization. So, in the situation where you had this cold weather, correlated forced outages, they would affect the existing system, but not the new resources.

Additional detail can be found in posted resources covering this resiliency topic – see additional material for the May 25th meeting.

Member of the Public: Extreme Weather Scenarios

When you say extreme weather scenarios, are you talking about a specific duration?

PNM Response

Each of these scenarios was roughly a one week-long weather event. For example, the 2020 heatwave was roughly August 14 through August 20. The cold weather event was February 13 through February 19.

We’re focusing in on one week but when we ran the simulations, we ran the whole year, but we parameterized the simulation so that they included in that time period those one-week periods, the weather conditions that occurred, the outages that actually occurred, the market conditions that occurred, and other factors.

We ran the simulations for a full year to make sure we were getting the right mix of Monte Carlo forced outage draws. The results, then, focused in on how the systems performed during those one-week events--one in the summer, one in the winter.

The different scenarios are on slide 48, 55, and 56. Tables on Slides 55, and 56 go through what the different scenarios for the winter event and the summer event were and give a brief discussion on why we thought this was a good a good sensitivity case to study.

InterWest Energy Alliance: RTO

How do you think joining an RTO [Regional Transmission Organization], or forming an RTO would affect some of the conclusions you've reached?

PNM Response

So, there is a potential benefit--certainly, a long-term planning benefit in terms of helping to optimize the capacity across the region a bit more. But this certainly doesn't completely eliminate the need for new capacity resources--just perhaps dampen it a bit.

InterWest Energy Alliance: RTO

I know an RTO is not a short-term fix, but shouldn't your longer-term look include looking at RTO development and doing the transmission upgrades and new builds needed, first identifying those, and then including them in your planning? Doesn't this all support that direction for your IRP?

PNM Response

In order to get to a deeply decarbonized PNM and the West, you're going to have to have a lot broader coordination, likely involving transmission and RTO type organizations to make that work.

A future meeting will discuss transmission planning and how that may or may not work in the IRP situation.

PNM as a company will continue to look at opportunities for collaboration and potentially joining an RTO, but it's going to take a while for something like that to materialize, probably not in this decade.

When we start thinking about transmission planning in the Integrated Resource Plan, there are some specific things that make that more difficult than people think. It has to be looked at a bit differently, including the models we will use.

We are bringing in a nodal production cost model, an enhancement to the current Encompass product we use. In order to really analyze transmission, you have to be able to look at the nodal aspects of things and have specific types of models that take into account the DC power flow to really understand the way the transmission flows are going to work.

Pipe and bubble is okay. I know there are some entities out there like Pacific Corp that incorporate a pipe and bubble transmission type topography and incremental transmission into their IRP. But that doesn't substitute for the type of work you'll actually have to do when you're doing real transmission planning, and generation interconnection studies.

PNM retail system only represents about half of the overall usage of the entire BA transmission system. And then we think about moving that out more broadly into the entire WECC. There are going to be benefits to doing some collaborative planning, but in the Integrated Resource Plan, we have to show what the resources and associated investments are on behalf of the retail system only.

Given the fact that 50% of the transmission system is in the FERC jurisdiction used by non-PNM retail entities, there has to be a much different way you look at the way that transmission system investment and other things might be done--especially in light of the Open Access transmission tariff, the obligation that we have to do things for customers who might not necessarily be a part of the PNM retail system.

There are a number of idiosyncrasies that might make PNM different than some other entities out there. We were considering trying to do transmission planning in the context of integrated resource planning, as opposed to letting the transmission planning department do transmission planning and then hopefully joining an RTO down the road.

InterWest Energy Alliance: Adding California to E3 Analysis

Your regional scope includes New Mexico and Arizona, but it does not include California or any other part of the Southwest. How do you think your conclusions would change if you added California?

E3 Response

That's correct. The focus was Arizona and New Mexico.

Had we included another region, like California, within the bubble of a study like this, one of the effects that we wouldn't expect to see is that, with a little bit more diversity in loads and resources, there might be some opportunity to share resources in terms of their contributions towards resource adequacy. Now, that does assume or contemplate this perfect ability to share resources across the extent of the system, which might not be possible given transmission constraints, as well as the sort of institutions around the bilateral markets that exist today.

So, in some sense, there may be a theoretical physical benefit to a broader sort of footprint, but there are also limits on how much of that is achievable today.

Those are some of the conclusions that we've reached in this study. If we had included California, I don't think our perspective on this would really change at all. In fact, it might become even a little bit more extreme. We do know that California is at the same time facing a very immediate and real need for new investment in capacity. We've seen this reflected in recent decisions from the CPUC [California Public Utility Commission], including the midterm reliability decision, which, if you're following that process, is the one that authorized over 11 gigawatts of new capacity resources within the state by 2025-2026.

At the same time that we're looking at a historical rate of capacity additions needed within the southwest region, California is in a similar boat itself in terms of needing to move very quickly but facing challenges in terms of near-term deployment and supply chain resources.

Pine Gate Renewables: Net Energy Peak

You talk about LOLP being the gold standard, like moving to ELCC and different types of ELCC methodology. How are you looking at the net energy peak for this scenario? Or are you just looking at one hour in the peak summer evening after solar has ramped down?

Initial Response: E3

We used an LOLP [Loss of Load Probability] model to simulate the sort of dynamics of this grid on an hour-by-hour basis over the entire course of the year in order to identify which periods we expect to be the most constraining. Naturally, that leads us usually to find that those net peak periods are the ones that will be the greatest challenge to reliability. You'll see that reflected in some of our results. In order to identify those periods in the first place, you do have to begin with the survey across all the different conditions, whether it's peak, net peak, or any other part of the year: How does the relative sort of balance of loads and resources stack up against each other?

PNM continued.

As it relates to PNM, throughout this IRP process, we'll talk about the different values that energy storage provides, and how the economic analysis is conducted and takes into account the different value stacking of energy storage services.

Regarding ELCC [Effective Load Carrying Capacity] analysis, when you're running the loss of load probability models, you're going to rerun those every so often as your system changes. The amount of effective load carrying capability for a resource is going to be relative to the risk hours of the system, which will change as the system changes, and use the accounting mechanism to relate that back to your peak period.

You see the declining ELCC per solar because the risk hours are moving further and further away from the gross peak to the net peak, and where the contribution then of the solar resource, in and of itself, no longer provides the same capacity for the hours of risk on the system as it did at the time when the gross peak was the risk.

So, we are rerunning those loss of load probability models every so often. This will capture the dynamic changes of the system, and how the relative effect of load carrying capabilities of each resource type changes as the risk hours of the system change.

Pine Gate Renewables: Storage

How are you thinking about the participation of storage in the market, given it might not be a wholesale electricity market by then? What are all the different services that the storage is providing? Does that change with the type of market structures?

E3 Response

In this effort, we're mainly focused on the questions around having enough capacity on the grid during the most constrained periods to maintain reliability. Our focus was not necessarily to conduct a detailed assessment of all of the different sorts of operational dynamics at play down to, say, the 5-minute interval at every instance of what the system looks like; or look at how energy storage behaves in different market constructs, whether it's providing ancillary services or energy, or some combination of the two.

Our focus is really on the periods where you need those resources the most: Will there be charge left in the tank for those resources to dispatch discharged to the grid? And so that requires some representation of the sort of charging and discharging cycling behavior of those energy storage resources. But it's not a really detailed operational analysis of the minute-by-minute or five- minute-by-five-minute sort of dispatch dynamics of the grid, under different market constructs.

Member of the Public: Contingency Reserve Requirement

It seems to me that [your resource planning] approach could also be for, say, planning on the contingency reserve requirement, or instead of maybe a severe event, it could be a severe curtailment of some generation resource or market resource. Could something like this be applied to that, assuming that the current standard doesn't change?

PNM Response

The contingency reserve or contingency reserves are set through the reliability coordinator. Through this type of framework, if we start to see more and more load shed, and we're thinking about how we build this framework into our planning, it can lead to a utility such as PNM carrying more resources. And if our operators think that they need to carry more contingency reserves, whether it's in the form of storage, quick start gas, or anything else, that will manifest itself through the planning process and that mechanism.

There's nothing that says we can't carry more than what's required. We just can't carry less.

Technical Session #1: June 8, 2022

CSolPower: Progress So Far

Have other systems reached 100% decarbonization? There should be others like Hawaii and Vermont and a couple of other states that maybe are planning on it? What are they doing?

PNM Response

This is going to be a growing area of work though nobody is at 100% right now. We're going to be figuring that out, and PNM is going to be one of the ones leading the way, just given where our system is going to be in 2023. If we're thinking about 1500 megawatts of solar, 700 megawatts of storage, and 600 megawatts of wind on a 2000-megawatt system, we're past California. We're way down the path ahead of just about anybody else.

CSolPower: FERC Standards

Does FERC have any standards for utility?

PNM Response

No. FERC designates reliability coordination to NERC, which has a number of different entities working underneath it. Those entities do maintain operating contingency reserve requirements that they monitor for all of the balancing area authorities, but planning reserve requirements, number of resources on the system, LOLE [Loss of Load Expectation], and other things, are left to the individual balancing area authorities and their state regulators to determine what is appropriate.

CSolPower: Other Battery Storage Technologies

This battery penetration is assuming it's all lithium-ion batteries, and you're stating that it's 4-hour capacity. Are you going to include other studies on other energy storage methodologies or technologies?

PNM Response

The particular chemistry doesn't make a difference on the ELCC [Effective Load Carrying Capacity]. It's the duration that will make a difference on the ELCC. Yes, there will be different presentations of different ELCC curves at different durations, just like was done in the last IRP. If you were to go to Appendix M in the 2020 IRP, you can see ELCC curves for 2-, 4- and 6-hour storage; we can extrapolate up from there, but we do run multiple iterations.

CSolPower: Battery as Percentage of System Capacity

Does this particular graph (Slide 18) relate to battery penetration in megawatts? How does that relate to the percentage of the capacity of the system? Or it's related to solar and wind?

PNM Response

This is a marginal ELCC curve for 4-hour storage, so the parameterization around the existing system would have been the known wind and solar that had been approved for the system, which, in this case, was around 607 megawatts of wind and 1026 megawatts of solar.

This was how the existing system was parameterized for the 2020 ELCC study. In terms of the penetration level, we're roughly a 2000-megawatt system. As you go up, if you're getting to 1000 megawatts, that's roughly 50% of the system on a nameplate basis, but what this would be saying is that on an effective capacity basis, it would only be at 60%.

That's the whole idea behind the ELCC piece: You need to understand relative to the amount of nameplate capacity of a resource--how much can you actually count on when you really need it. And the greater the penetration, the less you can count on it.

CSolPower: Extreme Weather Predictions

Have you considered accounting for predicted extreme weather? We know the climate is changing and these extreme events are becoming more common. The weather is definitely getting hotter. Looking backward may not be sufficient to give us a realistic view of what's going to be happening in the next 40 years. Is there any effort to work with NOAA? I'm sure that they have done some modeling as to predicted weather.

Initial Response: PNM

One of the things we've been talking about in our load forecasting discussions is to look at 2020 or 2021, where we saw a summer heat event and a winter event. If we were to take a calibrated, load weather relationship, do some specific sampling of the weather variables from those known years, and increase the frequency of them or maybe increase the magnitude of those temperatures, could we then use that to create what we think is more representative of a load weather relationship 10 or 20 years from now as it's affected by climate change.

The uncertainty is going to be how quickly we see this transition to more extreme weather happening. We know we've been seeing more frequent events, but history is not always the best predictor of future events. How do we start to get our hands around it? What is the right increase of frequency? Or what is the right increase of magnitude of temperatures? Both in terms of cold and hot. It's something we're thinking and talking about.

We don't know that it changes the way we would do traditional resource adequacy modeling. It does offer up a separate idea about how we would consider resiliency or extreme weather by creating perhaps a single weather year--we'll call it climate change weather--that we would be then utilizing to test a portfolio that's developed using the traditional resource adequacy framework.

And then, are there additional things we need to do in order to protect ourselves against the effects of climate change when we put in the extreme weather pieces?

E3 continued.

What we see is that forecasting the climate is more in the realm of possibility. For example, 'Next year, it'll be a hot summer.' What is incredibly challenging computationally is forecasting hourly temperature for the next 10 years.

For the 2020 IRP, we took the weather as is for the resource adequacy work, but we have explored taking the trend out of the weather. So, if we see a trend of a degree and a half or two degrees higher over a 40-year period, whatever the numbers are, we can adjust 1980 weather up by its amount, 1990 by a little bit less. It's a simplistic way of trying to get all the weather years on the 2020-type basis. That's going to increase temperatures a little bit in the earlier years and have very little impact on the most recent years.

The harder question and the question that's going to actually impact results more would be how to make the prediction of what is going to occur. And so, there are a couple different ways we could do that. The difficulty is defending whatever you assume. If we assume that 2020 was a very hot year, and we want to either put more weight on that or duplicate that event more frequently, that's something that can be done in the modeling. The difficulty is who applies and how you apply those probabilities and the frequency of when they occur.

If we are looking at the temperature just rising, there is an easy way to get to that. At the end of the day, your results aren't really going to be impacted that much. But to the extent we change the frequency and have these extreme events occurring more often, it's a harder thing to do. More likely it's going to impact the liability and ultimately the planning reserve margins much more.

PNM continued.

We welcome ideas from stakeholders on what is a reasonable approach for adjusting the frequency of events, or temperature increases going forward. The whole purpose of the technical sessions is to start trying to take ideas from a high level and work them in the modeling framework.

Sandia National Laboratories: Distribution of Uncertainties

Regarding the distribution of uncertainties, you mentioned that you had book-ended the window of your uncertainties. Are there any? Have you investigated looking outside that window at extreme cases that might not have happened over the past 40 years? That might be an interesting exercise.

PNM Response

This question gets into the reason for the resiliency work that we just did--drawing the separation between traditional resource adequacy modeling and how we need to start thinking about extreme events. How do we want to start utilizing that framework for some of these IRP portfolios?

So, for example, we saw in the presentation of the resiliency study that traditional resource adequacy modeling is about those stochastic variables that are pretty well understood and have pretty well-defined probability. But when we get into the resiliency type framework or extreme weather analysis, we could use some stochastics within that, but we really have to come up with some deterministic scenarios in the way we parameterize.

We want to use the question posed here as a way to springboard into this next step of thinking about how we start incorporating that framework into the IRP. Are we running our most cost-effective portfolios through the same type of resiliency framework? Is there something else that makes sense?

We do need to move in that direction, not just focusing on the traditional RA modeling, but also taking some ideas and lessons learned from our resiliency work and extreme weather analysis to come up with a second framework.

See also Technical Session #3: July 6, 2022.

Sandia National Laboratories: Monte Carlo Simulations

Are you using Monte Carlo simulations with forced outage rates of the resources to run the LOLE models?

PNM Response

The answer is “yes.” We're using SERVM [Strategic Energy & Risk Valuation Model software] to calculate the LOLE [Loss of Load Expectation]. That is a sequential commitment and dispatch with Monte Carlo

outages. And we capture all the intermittency related to solar and wind. So, we're using solar profiles and wind profiles, which change by weather, and we're capturing all those different uncertainties in the model.

Member of the Public: Baseline for Summer/Winter Resilience

If we are looking at establishing a baseline level of service or capacity for summer or winter resilience, are there any contractual requirements if greater demand is placed on the West as a whole, such as if Hoover or Glen Canyon Dam are no longer able to supply power? This may, if there are contractual agreements, affect the sizing of systems.

Initial Response: PNM

PNM does not have any contractual requirements, aside from its participation in the reserve sharing group. That's a very narrow window: If there was a contingency or some other thing that happened among the SRSG [Southwest Reserve Sharing Group] members, PNM may need to be able to provide a proportionate amount of contribution to aiding in the reserves for the group.

PNM doesn't have any contractual off takes from the Hoover Dam. But if entities such as NV Energy have some uptake from the Hoover Dam and if the dam no longer is able to produce as much energy and capacity as it has in the past, the main effects that PNM would see are a smaller available market or the other entities that are trying to cover that loss of power are now trying to purchase energy capacity in the same market that PNM is participating in, reducing liquidity and driving up prices and scarcity.

We do not have any contractual obligations to cover anybody else's share if some of those hydroelectric facilities are no longer able to produce it at historic levels. But we would be impacted indirectly through what we might be seeing in terms of ability to procure capacity and energy on short- or long-term markets.

E3 continued.

The risk of increasing drought or sustained drought in the West, and its impact on power markets, particularly in the Southwest, is something that we tried to explore a bit in our study. The main effect would be indirect through its impact on the availability of the market during the times when you need it.

Brubaker & Associates: Market Assumptions

How is transmission going to be worked into the IRP? What assumptions are going to be made about market support? What are the plans to tackle ELCC?

PNM Response

Brubaker & Associates and InterWest Energy Alliance have filed some comments regarding a number of things related to this topic and we're hoping that you are going to share some of your ideas with us.

This IRP is not going to be able to do a full-blown integration of transmission. We'll have a specific technical session on transmission, and we'll see what we can do. We're working with our transmission group, and bringing in the nodal version of Encompass, which is our power planning software.

Doing generic transmission doesn't make a lot of sense; you really need to have a known starting point and ending point for the lines to try to figure out where the resources are going to be. We have some ideas, similar to what we did last time, in terms of ways to modify the pipe and bubble setup. We don't believe we're going to have the nodal version ready to go. We're still getting that setup data worked out.

So, we're thinking about ways where we can take some information, perhaps from the previous higher-level RFPs, which have some regional differences in prices, and work with some of the transmission information that was in the last IRP to better understand how some of the resource pieces would work. But that obviously doesn't take into account transmission upgrades that might work better on congestion management within the existing system.

We want to try to do what we can to be sensitive to stakeholders' desires to have more transmission related information in the IRP but it's going to take a little bit more time before we can get to a full-blown integration of transmission there.

On the market import piece of it, at this point in time, we don't have any information that would tell us that we should be allowing for more market. We're going to see what happens over the summer. What we're seeing right now is that the markets are still severely constrained. We haven't said anything about going to a tighter requirement on the market. We think we're probably going to stick to where the market requirements are. But we do have a commitment with the stakeholders to meet this fall to talk about the market assistance in the modeling. That'll be definitely something that we're going to discuss.

We're going to be updating some of the neighboring modeling and the server model to help try to capture more specifically how our neighbors' portfolios are going to change over time. That may add some additional insight into how the market imports are working out.

We saw in the Southwest Resource Adequacy in the Desert Southwest study that, if everything is aligned, there's enough on the entire region; but just because the model says there's something there for the entire region doesn't mean the individual actors within the region are really able, and willing, to share that, given what they might want to hold back for their own needs.

What we have actually talked to some counterparts about is that they may not be willing to sell if they're getting in trouble, because they don't know that, if they let resources go, they're going to be willing to meet their needs if, for example, a unit trips, or especially if further down the road it's a question of more storage related for capacity.

So, we think at this point what we're going to be moving towards is a continuation of the same market assumptions that we had in the last IRP. But we're definitely willing to talk about that. We know there are questions about a formulaic way to do this and other things we can be looking at. But right now, our wholesalers are very limited in what they're able to do.

Day ahead and bilateral transactions are really what we're focused on concerning this question. It's not what can you get a year ahead and put on your L&R table; rather. the question is, if we go in with an open position, what do we actually think we can get a day ahead in real time?

As far as the ELCCs, we do have some thoughts. We're going to be updating the ELCC study. We have some thoughts on some ways to use some information from last time to get some better synergy values. Again, if there's any work that stakeholders or others have been doing, it would be a great springboard into the modeling framework.

We also need to be cognizant of the limitations of Encompass and how can we work the synergy ideas into the way that the internal ELCC logic is implemented within Encompass. We've got some ideas, but maybe others have some ideas, too.

And then we may have some information from others that are just starting to tackle ELCC issues for renewables more in depth. So, we'll be glad to forward some information on that as it becomes available to us. That might be helpful in the discussion.

CSolPower: Tradeoffs

[In response to the question about tradeoffs, I would definitely go for carbon-free over .1 LOLE. That's just my statement: I would choose that we go carbon-free first. I would rather have one less day of no power, considering all the extreme weather events that are going to result from carbon emissions.]

PNM Response

For clarification, we were asking, 'What's the way we would rank things regarding the reliability versus the environment costs tradeoff?' We would hazard a guess and we could appreciate that many stakeholders would be okay with a less reliable system if we could get towards carbon-free faster.

Sandia National Laboratories: Inertial Requirements

While doing the planning, have you taken into consideration the inertial requirements of the system to maintain frequency security as we replace more conventional generation with renewable resources?

Initial Response: E3

Yes, the short answer to that question is "no." This isn't a study that has looked at those questions around the inertial requirements of the system. It's purely focused on when we stack up all the capacity within the region on an hour-to-hour basis: Is there enough total capacity to supply the region's demands?

PNM continued.

From PNM's perspective, it's the same answer to some extent. The way we're looking at it from the integrated resource planning perspective is looking at the resources--the loads, the typical economic and reliability related production costs simulations. Outside of this group, more in our operations department, they are doing more work on inertial requirements, taking a look at power flows, transient dynamic stability analyses within the transmission and distribution systems. And, even today, they're starting to see things come up in terms of the ability to maintain inertial requirements under specific disturbances, depending on how many renewable resources are producing at that given point in time.

So, that is a focus within the company. It has not been worked up into the integrated resource planning process, yet. It's more of an operational issue.

Member of the Public: Loss of Load with Electrification of Economy

Does the [electrification of the larger economy] impact the loss of load probability or the loss of load expectations in any way?

PNM Response

As long as we're building up expectations of increased load into the load forecast, we are using in the loss of load probability modeling, then we would be capturing those effects, and we would be targeting additional resources to be included in the portfolio to meet that additional load.

The work could fall short if there's an increased movement towards building electrification, or there are other aspects of electrifying the economies that are not foreseen within the load forecast, as well as load forecast errors within the loss of load probability modeling leading to increased loss of load risk if you're not adding enough resources to cover that uncertainty.

We have been talking with E3 about the question regarding the difference between planning reserves and contingency reserves. We will also follow up on the question of setting our planning reserve margin requirement and doing our loss of load modeling or resource adequacy modeling.

Doing the IRP cycle every three years, we're putting in our best estimates of the load forecast when we're doing our load modeling and setting up what our reliability metrics and our ultimate planning reserve margin requirements will be. Within the service framework, one of the Monte Carlo variables is load forecast uncertainty, and that's separate and apart from the load uncertainty associated with weather, and so you have some of the LOLE [Loss of Load Expectancy] risk that is then embedded within the model is associated with what happens if we under forecasted the load--not just the weather changing the load more than we expected.

Doing the IRP every three years we also get a chance to redo, reset, the Planning Reserve Margin (PRM) if we need to procure additional resources. So, we don't think that the entire economy is going to electrify so quickly that we won't be able to adapt as we're moving through this iterative planning process.

InterWest Energy Alliance: Batteries (2-hour versus 4-hour)

Your [example in the presentation] used a 2-hour battery. That doesn't seem to be a good assumption. Why not use a 4-hour battery since those are available now?

PNM Response

It was just an illustrative example. The whole purpose of the IRP is to determine the mixture of resources and storage. It's a mixture of capacity and duration that we're going to need to meet our reliability requirements. Some different durations of storage will have different ELCC values.

Given the penetration of storage that we're expecting on our system relative to what's already been approved by the Commission, we don't even think four hours is going to be doing a whole lot of justice to our system going forward; we're going to be needing to look at six, eight, and even longer storage when we think about what's happening in other jurisdictions. For example, California has been starting to add some eight-hour batteries--PG&E recently did an RFP that looking only for an eight-hour battery.

So, even four hours is too short at this point, if you've got even a modest amount of storage on your system, as a penetration of batteries on your system grows, the finite duration of that battery is going to

limit the amount of load carrying capacity it has. And that's what leads to that decreasing ELCC for storage.

Brubaker & Associates: Synergies Across Resource Types

[Recalling concerns expressed (by Grid Strategies, LLC) in response to the 2020 IRP]. I think the thing to think about is that you are making assumptions about where you're going to be in different time frames so that you can divide up the synergistic benefits across the different resource types. Is this in any way directing an outcome and the economic optimization that will take place later? And what might be revealed is if you start going in a different direction in the optimization, then you are assuming where to balance and what the resources are going to be?

You might be pretty close, and it is certainly going to be a lot closer than what was previously assumed to be benefits.

Initial Response: PNM

So, if there are other ideas stakeholders have considered, we would love to hear them; you can share anything with us in a presentation for stakeholders this year or next,

You do have the question of whether the synergistic values you're inputting are driving the results too much or, by using the 2020 IRP as kind of framework, assuming that it was relatively close in its outcomes, we would think that this should be a reasonable approach. [Perhaps there is a] better way to do it--We'll talk with Anchor Power Solutions about whether they can build something like this into the optimization model.

If you had enough ELCC parameters done, you could set up within the optimization a binary variable for each different equation, relative to the bounds of the penetration levels of each resource type and have a sensitivity factor on each. And then that binary variable has to sum to one. So, you're only at one equation in the given point in time. But if you come up with, say, 50 different equations for each year, and you've got to add that for the 20 years of the optimization, you're introducing 1000 binary variables--that's very computationally expensive.

So, if there's a way to do it within this framework, which is 100% polynomial time, it's because it's all continuous variables, as opposed to adding those binary variables--it gets a little bit more computationally efficient.

E3 continued.

Regarding the 2020 IRP, we don't want to say there wasn't any synergistic value out in the future, because even our existing starting point had 1500 megawatts of solar. So, when we looked at marginal battery, there was some synergistic value captured, and that is why we didn't feel like it was as necessary.

But we do believe that if that 1500 MW of solar goes to 3000 MW, there's probably even some additional, so we don't want to leave stakeholders thinking that last time there was no synergistic value out in the future, because the starting point might have been somewhere between 300 and 600 megawatts of storage and 1500 megawatts of solar.

Brubaker & Associates continued.

I think why it became such an issue the last time was that when you did the San Juan Unit 1 & 4 replacement resources, we just sort of iterated on the economic analysis back and forth between Encompass and SERVM.

So, for PNM particularly, a lot of the issues on synergies became more apparent and accountable, because, ultimately, with SERVM economic numbers, and then the IRP and the Palo Verde lease replacement cases, we really relied on the economics from Encompass, which I think was good. But then the concern was capturing the energy benefits. So, it was good that part of it was captured but I think the idea is to try to definitely get more into it.

PNM continued.

That is absolutely what we're trying to work towards. We did a really good job with the near-term synergies, if we're thinking about the Palo Verde case, when we're talking about doing replacements, in

2023, and we know that our 2025 calibration was pretty much spot on. So, we don't see too much of an issue there.

We know that everything's going to change before we get to 2040. We're trying to look at pathways now, doing things to sharpen the pencil and working down that route. Now, the most important part of this IRP is the action plan. We want to show our pathway, but we want to make sure that the near-term action plan is the primary impetus.

Brubaker & Associates: LOLE versus EUE

You might have to potentially look at both LOLE and EUE. This raises a question: Which is more constraining? The other thing that comes to mind is that it may be that EUE is a better metric than LOLE when it's looked at more carefully; it more optimally identifies how much capacity you need to get a certain level of reliability or, more broadly, resilience.

PNM Response

This is exactly right. When we think about what's the right baseline, if you had a traditional system that was designed to meet a LOLE [Loss of Load Expectancy] metric, there would be a certain amount of EUE [Expected Unserved Energy] we associated with it. So, what the baseline we should be using? Is there something else?

If you're going to do a planning reserve margin requirement, are you still going to base that on LOLE? Probably. If you're going to use a EUE ELCC study, you're going to need to probably adjust your PRM [Planning Reserve Margin] or you're going to have a situation where, if you're using EUE-based ELCC curves, you're exceeding your targeted PRM; if it's based on LOLE in the event where you've got EUE being more binding metric.

These are all things we are definitely should be considering and looking for feedback in terms of the right way--or the perceived right way--to go about this. we don't think anybody would question that at some point in time it's going to be energy that's more constraining than capacity.

Sandia National Laboratories: Storage Duration versus Storage Volume

Is storage duration critical? Or is storage volume more important? And what is the cost tradeoff? I would say it depends a little bit on what the application is. Are we trying to farm up wind and solar or are we trying to use it as backup? That's something I would be willing to help with as well.

PNM Response

Once again, we'll take you up on that. And we've been doing a little bit of looking at things here. And it kind of depends, when we look at the system going forward, we've got carbon intensity requirements: We've got to start serving our customers, on average, with 400 pounds of CO2 or less beginning in 2023. This is related to Section 10D of the energy transition, and that goes down to 200 pounds in 2032. And then, of course, carbon free by 2040.

When we start to think about it, we've done this with some different load shapes, depending on what you want. And then, of course, there's incremental, potentially carbon generation in the system that, if you've got gas resources on margin, and if you start thinking about that, you've started trying to figure out, say, I want to do this all with solar and storage, how much charging capacity do I need? And how much total volume of energy do I need, depending on what those carbon requirements are to offset things?

By time shifting your solar from on peak into the off peak, maybe you should say excess solar and, some of the preliminary things we found is that, really, a lot of the requirements end up being driven by the winter period, especially as you get towards carbon free, because you have the shorter daylight producing hours. And you need to have that greater charging rate in order to sufficiently charge your storage resources. But then you're going to discharge them at 1/3 of the nameplate capacity to allow for a greater durational discharge over a period of time to sustain, from a sun set to sunrise kind of thing.

So, it's a very interesting topic. If that's your area of expertise, we would love to learn from you. And if you get if you got some papers, and you want to sit down and talk, we'd love to have you over in the office, or if you want to give a presentation, you're welcome to do so. Yes, we appreciate the insight that you can work with us. That'd be great.

So, the way we size the storage, it mostly can be customized to various applications. We were looking at the mean downtime. That's another important metric as far as reliability is concerned.

Sandia National Laboratories: Baseline for Portfolio Metrics

How do we establish a baseline for portfolio metrics such as EUE, which has been around for a long time now? If you look at literature that goes back to 1970s, you can see the matrix calculated there. So, there's a lot of literature out there which have used IEEE test systems to calculate the EUE for a lot of systems and a lot of scenarios. Maybe that is something you would want to look at as a starting point for establishing a baseline. And I can help you with that if you want.

PNM Response

Yes, we're doing some digging for that. It would be terrific if you have any publications or links that you could send to share.

Technical Session #2: June 22, 2022

Member of the Public: SERVM Stress Test

Can you apply the service stress test to the significant low carbon portfolios you produced in your IRP capacity expansion model?

PNM Response

The answer to that is "yes." That's essentially what the resiliency study was doing now.

SERVM [Strategic Energy & Risk Valuation Model] works on a year-by-year basis, rather than doing all the study years at once. In the resiliency study, we looked at 2025: The big change in the portfolio we were considering was the removal of 200 megawatts of affirmed dispatchable coal generation and what some of the replacements for that might be. So, what we did was look at that IRP type portfolio for 2025.

Moving forward into the current IRP, we certainly can set up alternative years and look at, say, 2040. When we are not anticipating being carbon-free, we can look at an interim year—such as the main years where we saw some big changes in the portfolio. Along with 2014, another big year is 2032, when we have a new carbon intensity requirement that we have to meet.

That's one of the questions we wanted to pose to stakeholders: Is it appropriate, or should we be taking a look at, say, for the most cost effective portfolio some of those key years or do we want to look at 2025, 2033, and 2040 and run through some of those same resiliency and stress tests, making sure that if we're going to be decarbonizing we are meeting all these different reliability metrics, as opposed to just meeting the loss of load expectation metric? The genesis for that question was this resiliency work, seeing that there are different portfolios with different types of resources; while they can be normalized for equivalent probability of loss, a load event will perform differently if an event occurs.

Member of the Public: Fossil Fuels

We need to keep talking about fossil fuels: how they are being phased out and where those options are. Sometimes additional, more attractive fossil fuels, like gas versus coal, need to stay in the conversation in this transition period because the public doesn't really understand this issue very well.

PNM Response

We agree with you 100%. A transition should happen over time, not overnight.

You know, having some gas resources that are seldom used, but used when you really need them, is an important backup to this system. A lot of entities across the United States are still doing that. For example, Duke Energy has a carbon reduction plan. They operate in North Carolina and South Carolina, and they've got legislation that requires them to reduce carbon by 70% from 2005 levels by 2030. One year, while they will be getting out of coal completely, they are still planning to operate and potentially add new gas resources along with solar storage [and] things of that nature.

Keeping all options on the table is really important. So, we don't think that we should be taking gas off the table for our list of candidate resources. There are gas technologies that are efficient that can be converted to non-carbon emitting fuels down the road. And that can provide that reliable backup service for those renewable droughts and other periods of time when you really need to make sure that you've got a reliable system.

So, we appreciate the comment, at this point in time, we want to keep options on the table and make sure that we're talking openly, factually, and honestly about what we need to keep the system reliable, that can help us in this transition, and make sure that this transition is successful.

Technical Session #3: July 6, 2022

New Mexico State University: Heat Waves

We've heard that the average temperature in New York or for PJM (PJM Interconnection LLC) was going up .7, and we don't really know what the trend is for New Mexico. I'd like to see a scenario that does take into account the increased occurrence of heat waves in the summer, because that's what's going to stress your system. So, can we look at the trends we know about in New Mexico, project out increases in heat waves, and make a scenario for that?

Initial Response: PNM

We understand the question as asking if we could somehow work into the forecast an increase in the frequency and the number of heat waves in a given year. That's something we've talked about a bit internally, including some ways to do it.

The question is more appropriately covered in our reliability, stochastic modeling, and not necessarily something that we would build into a base load forecast. But once we have a properly calibrated load weather relationship model, we could, say, go to 2021, where we saw a couple of heat waves that were pretty geographically widespread, use that as kind of a base weather system, run that through the load weather model, and come up with a load forecast where we are using a period of time as opposed to using normal weather or something to that effect.

Itron continued.

So, as we do the 2040 hourly forecasts, we're running a daily weather pattern through and that can be anything that we want it to be right now. It has a typical hottest day in each month, typical second hottest day, and down to the typical coldest day, So, it represents fairly the range of weather that we've seen based on that 20 years of history, and the hottest days. So, we've got 20 hottest days; you average them and that's our hottest day. (Take the hottest day from each of the 20 years, freeze the 20 years, and average them.)

That's what's driving our peak forecast right now. And the day before and the day before it--those things matter in the modeling. So, the pattern matters as well. We can put whatever pattern we want and see what the implication is.

PNM continued.

That is captured more in our stochastic reliability modeling. And in terms of the way you know a couple of increased frequency of events affect the system, even if you're putting in a different pattern, it's still normal weather, and it's still within the same operating temperature ranges.

It probably would not have that big of a difference on the general portfolio, depending on the duration of some of those events. Maybe you start to see a bit of an increase adoption of more firm dispatchable resources or longer duration storage. But overall, the frequency of events is that it's not going to change--the capacity builds that much.

Itron continued.

And then there are parameters in the model that we can look at and anticipate the impact of an additional degree to the day, the day before, and the day after. If we go through those three parameters, there's some number like 20 megawatts per degree. We'd have to look at the slopes to know what those are.

PNM continued.

We welcome specific requests; for example, an ask to look at three extreme weather events per year throughout the period, with an increase of one degree per year. We want specific requests that we can put into a scenario development form to make sure that we're understanding the ask correctly.

We are planning a scenario building session on October 11, 2022, but the schedule may change.

NM State University: Load Scenario

We're mostly learning about how the baseline was developed for load, and how the stochastic scenarios affect production on the reliability side, but does the reliability model also apply stochastic variation to this baseline load forecast? Where would different load scenarios go?

PNM Response

Yes. The SERVM model that does our stochastic reliability modeling has 40 years of historical weather data. And it does stochastic variables, stochastic analysis on the load, as well as the renewable production related to the weather.

Take 2011, a year mentioned here as extremely hot in the desert Southwest. If it was sampling from the 2011 weather year, the model would then pull out the weather and apply that weather to the load as well as to the renewable production for a given sample day. You'd have that correlated effect of that weather year being applied to the base load shape, and the base, renewable production shapes with that stochastic weather uncertainty.

There are other stochastic variables--forced outage rates, economic uncertainty, other things in the stochastic model as well. When all are put together when we run that model, there are 40 different historic weather years, and a number of other stochastic variables. We end up having a little over 1000 single runs to represent stochastic hourly production cost runs. There are actually five-minute production cost runs that assess production cost and reliability for a given calendar year.

InterWest Energy Alliance: Heat Wave Analysis

Shouldn't your heat wave analysis also include a length in time, depth in temperature, and demand and geographic breadth since these are assumptions that affect your assumptions regarding market availability?

My point here is that in the last IRP analysis, some of the assumptions regarding availability of market resources regionally depended upon your assumption about heat waves, how deep they were going to be, how often they were going to be, and how regionally broad they were going to be. And the assumption was that everyone else in the region is going to be encountering the same heatwave at the same time. So, they're all going to be holding on to their resources. And there will be none that PNM could potentially draw from.

My question is, if you're going to apply that same assumption this time around--I think that there's an underlying assumption in this cascade of assumptions regarding your heat wave analysis--are these heat waves becoming more geographically broad so that everyone in the Southwest experiences the same heatwave at the same time? And is it as deep for everyone at the same time, and does it last as long over the same time span for everyone so that your market availabilities are limited?

PNM Response

The last time we did not assume that there was no ability to purchase from our neighbors during times of maximum constraints we did assume that there was a limited ability. We didn't just allow for unfettered transfer of energy within the model.

When we're doing the IRP, we have to look at PNM retail, and we have to make certain assumptions about the boundary conditions outside of PNM retail. There's more load and more resources in the PNM Balancing Authority (BA) and then there are other loads and resources even beyond what we saw in 2020. And that's where the assumption that you're referring to came about-- when we had that geographically wide heatwave in 2020, I believe is August 14-20.

There were maximum constraints in the market, and we were not able to purchase more--the day of maximum strain was August 18, or 19. when we were not able to purchase. There was one hour when we were only able to purchase 25 megawatts; another hour, we're only able to purchase 75 megawatts, despite having basically an unlimited price; we were paying over $1,000 a megawatt hour, and we just weren't able to get anything.

And so, what we've been seeing, and we've been talking about is that there has been a drastic decrease in the number of counterparties available in the bilateral markets, there has been a drastic decrease in the number of transactions. We know that there are more and more retirements of resources going on and systems are getting constrained. We saw in Arizona recently that a planned natural gas plant expansion was denied.

We are talking to our traders every day and understand what the market conditions are like. And as more and more firm dispatchable resources get retired, as more and more systems you have predominantly are solar and then storage for capacity going forward, we do believe it is less likely that utilities, especially in the near term, are going to be willing to share energy if it's coming out of an energy limited resource like storage.

So, we're not making any decisions yet on what our assumption around the market availability for resources would be for times of maximum constraint in our reliability modeling. We'll revisit that after the summer and see if there's any new data to consider. Right now, we're thinking we're still going to use the same assumptions as we did in the IRP last time.

In 85% of the lowest hours, there were no constraints in the model for that. And when we look at the top 85 or the top 50% of load days, if it wasn't a gross load period, the market was limited to between 200 and 300 megawatts of market assistance during those peak gross load hours. And then when we got into the peak net load hours that were reduced down to 50 megawatts, consistent with what we saw during the 2020 heatwave when we weren't really able to purchase anything, and it was those hours, as the sun was setting and there were maximum drawn resources into California and otherwise, when we talked about some of the limitations in the model as well.

We're trying to update the modeling of our neighbors--the change in their resources based on their IRPs so that way, we can understand some of the better implications of how the market dynamics may change as regional systems change, not just as PNM's system changes. We were only modeling one timeline away, say Arizona, for example. Most of our imports come from west of us from Arizona. We got negligible transmission capacity coming in from the east and from the north. And there's not much availability to be able to bring things in across white path 47 from the south.

So, most of what we get is coming in from the west. And Arizona also sells a lot into California. And we didn't have California in the model as a sink. All of that energy that might have been excess in Arizona was assumed to be made available to PNM at a perfectly efficient market, which is just a simplifying assumption.

That's why we have to look at some of the actual data of what is occurring during these times of key constraints and not just say, well, anything a model says is 100%. And that's some of the flavor behind what we're looking at when we're trying to take the reliability modeling forward.

But the heat wave analysis per se is something that, as we model PNM loads, we need to consider outside of the PNM retail system when we consider that it is more in the context of what we think we could reasonably count on to bring in from other systems during times of constraint.

The more we take out of our control, the more we sell, we put ourselves at risk. Should we be planning that we're an island? Should we be planning on limited amounts? Or should we plan on unlimited amounts? And should we add to risk to the system?

Is it a balance?

See also Load and Energy Efficiency Forecasting.

Technical Session #4: July 27, 2022

Form Energy: ELCC and PRM Calculation

Will there be a more in-depth discussion of the first step discussed in this process? That is, the ELCC and PRM [Planning Reserve Margin] calculation methodology and SERVM?

PNM Response

We've had a few stakeholder presentations on ELCCs and the PRM methodology. There's some specific information in the June 8, 2022, and June 22, 2022, presentations, as well as in our September 15, 2020, presentation from the 2020 IRP.

We can certainly try to address any specific questions you might have. And we'll have more presentations once the ELCC study has finished. But in terms of having anything immediately coming up, unfortunately, we've already gone through some of that information. So, are there any specific questions you might have in that regard?

{Form Energy representative responded that he had nothing further -- He would go back and review the earlier material.]

NM RETA: Future RTO Membership

Does the energy market input include future PNM membership in an RTO in the later years of the IRP?

PNM Response

There's no specific representation of an RTO within the model going forward.

If we take a step back, we'll see that there are two different places where we look at energy markets in the modeling.

The first would be when we're setting up our planning reserve margin requirements to SERVM. What level of market support from external entities outside of PNM's control are we willing to allow to contribute to the planning reserve margin requirement?

The second piece would be when we do the capacity expansion modeling. We do not allow that, except for whatever that specific reduction to the planning reserve margin requirement is, as an input. We don't allow purchases to be used to meet capacity and energy requirements when determining what the preferred resource bills will be for any scenario, nor do we allow sales to be included. We don't want to have the system being built for speculation; we want to make sure that we're picking the right resources to meet our requirements for our retail load.

That's what we have to do in the IRP--look only at our retail load. We don't even look at the whole balancing area, the requirements under the New Mexico rule, or our retail load in the IRP analysis.

And then when we do the more detailed production costings, once that capacity expansion is finished, and the portfolio for that given scenario is set and locked in, we re-dispatch the system on a full chronological hourly basis every year for the full 20 years. And we allow economic purchases and sales to be included in that there's no restriction in that representation, in terms of the amount of capacity or energy that can be done in any hour, except for what we believe are limitations at the liquid hubs where we trade.

So, we're typically saying that's roughly 250 or so megawatts. And that corresponds to when we do a lot of our trading; we can typically do 250 to 300 megawatts of economy trades without incurring significant transmission cost. If we go beyond that, then there's transmission or hurdle rates that typically have to be included. That's the general setup.

We do fully anticipate that the West will move towards an RTO in the next 10 or 20 years. It's difficult for us to say exactly when. And it is even more difficult than to say, once they are created, how quickly we can do transmission planning. How quickly then could transmission lines get built?

So, there are a number of assumptions. We are supportive of the idea of an RTO but cannot say specifically when it will occur. And then to assume interconnection capabilities beyond what we already have here today is pretty speculative.

We will discuss some of these things a bit more in a future meeting on transmission modeling.

We've talked about this a little bit in the past when we brought in the Encompass nodal version of the model, which will allow for a full transmission constrained economic dispatch, not just of PNM retail system, not just at the BAA, but of the entire western interconnection. But it's going to be some time before we have that model, fully calibrated. Then, trying to use it going forward is something that's going to take place over time, at least as it works its way into the Integrated Resource Plan.

So, for right now we're focusing on what we've been able to see for economies within our existing operations. And regardless of whether we would be in an RTO or not in an RTO, we would not want to plan the system in a way that's going to be maximizing resource additions for the year to make purchases or sales. We still would have the obligation of finding a least cost solution for our retail customers, depending on how that RTO is set up, whether there's a capacity market, sharing of capacity resources, and other things, would depend on the market design of that RTO.

Technical Session #10: January 17, 2023

InterWest Energy Alliance: LOLE in Winter

Please describe why ELCC is used only for wind, solar, and storage. PJM's results from the recent [2022] winter storm Elliot in Texas and 2020’s Texas winter storm Uri showed significant severe thermal outages during peak need times.

Initial Response: PNM

We can talk about that a little bit, but that was also in the presentation that one of the members of [the InterWest] team, Michael Goggin, presented at a previous meeting. We've committed to look at this.

Fundamentally, one of the things that needs to be kept in mind is that the loss of load risk hours for PNM's system are currently in the summer. And so, when looking at thermal outages in winter conditions, that is not likely to modify ELCC results or PRM results or LOLE results for PNM's system. As we are still a summer peaking system and the risk hours are in the summer, winter outages like that are unlikely to affect the overall LOLE and system requirements.

Astrape continued.

I think you covered the main points [regarding] summer LOLE systems.

We don't really see this winter impact. We did, as part of a previous resiliency study for PNM that we worked on with E3, look at the cold weather outages over the last few years. The units actually performed quite well.

So, Atrape's MO is really to look at the data. And if the data doesn't show that we've seen those cold weather outages, then we won't capture them. Even if we did put in some additional cold weather outages, I think it would take a very significant amount to really start surfacing much winter LOLE.

But I do want to make the point about our reserve margin accounting. I know we're not talking about it today. We do capture thermal resources on a UCAP basis. So, we are essentially reducing their nameplate by some discounted value: we're using one minus EFOR (effective forced outage rate).

If there was substantial cold weather outages, and there was winter risks, yes, I could see calculating more of a winter ELCC for those resources.

PNM continued.

You hit it on the head. The data just doesn't show it with our system, in terms of the way our units have performed. There were a lot of winterization efforts that had gone into our fleet following the 2011 cold weather event. The data just doesn't show what the PJM data shows.

You have to keep in mind that those are different systems or different units. They have different attributes and different risk hours associated with them. So, we can't just take a PJM analysis and assume that it can be applied equivalently to PNM's system.

NM RETA: Minimum Storage

Is 650 megawatts of storage the recommended minimum for the PNM system to have operational by a certain year?

PNM Response

The 650 represents the known procured storage resources we expect to have online by January 1, 2025. So, that's where that number comes from. If we were to go back, a few slides where Astrape had the starting point assumptions for wind, solar, and storage, the 607 megawatts is the wind we currently have on the system, actually, and we don't have any approved changes to increase that level of wind by the time we get to January 2025.

And if folks that were to do some more digging. that 607 is actually 657, but there's 250 megawatts of wind that are behind the 200-megawatt interconnection. So, it's never possible to get 657 megawatts out to the system. It's capped at 607.

Then the 1,531 megawatts of solar and 650 megawatts of storage represents PNM's existing solar, and while there is no storage on the system yet, all incremental solar and storage additions that have been approved by the [Public Regulation] Commission, either in existing contracts, new contracts, and amended contracts have been filed with the Commission and are expected to be online by January 1, 2025.

So that's, that's where those numbers came from.

Member of the Public: BTM [Behind the Meter] Storage

How would PNM view independent solar, whether on individual, for example, a roof, or DG (distributed generation) context adding storage? What might those installations look like?

PNM Response

We would say that we can't require any individual customer to add storage, if they want to do something behind their own meter, as long as they go through the standard interconnection process, either for a rooftop edition or a small generator or large generator edition. We can't require them. We would like them to.

So, as we see more and more behind the meter storage added, PNM will likely need to start thinking about how can it best manage those additions, and it will likely be through other types of storage additions, whether on the bulk transmission level or on some targeted distribution feeders, to try to make sure that we can start maximizing the value of that solar energy that customers may want to put on their roofs--and ultimately would be putting back to the system as a part of their own interconnection.

So, the key takeaway from PNM's perspective is there really shouldn't be solar additions at this point without storage additions. If we just continue to add solar, there are going to be times of high curtailments. That's not good for the system and not good for customers. If we really want to maximize the value of the solar renewable energy, there's going to have to be additions of storage along the way as well in order to best manage that.

And it's going to have to be targeted on distribution feeders. It's going to have to be at the bulk transmission level. We're going to have to incentivize customers to add their own as well. Now we can't require them to but storage and solar work together. So, we need to find ways to make sure that we're not going to be disproportionately adding one or the other.

The system is really the key takeaway from Astrape's analysis here.

InterWest Energy Alliance: Wind Penetration to Storage Penetration

Is there a slide to show wind penetration to higher storage penetration?

Initial Response: Astrape

Yes, [but] we don’t in this in this deck. This just shows the movement as solar increases.

We could go back and look.

PNM continued.

Here's the 650 storage [Slide 53]. We've got wind penetration levels there along the front axis. And if we were to take this and keep an eye on that front left corner point, that will say, "Well, if we keep wind the same, and we keep solar the same, and we just move forward in time, how does that front left corner point kind of change over time?"

You're adding storage, but the bulk of the additions and the portfolio ELCC is really being attributed to storage. There's very little, if any, interactive effect between wind and storage.

Astrape continued.

Yes, that's correct. I don't know that we can really glean it very cleanly from here.

But yes, certainly, that's something that can be looked at with the analysis we've done. We generally think wind and solar is the main interactive relationship there. So that's why we put that in here.

PNM continued.

Everything that we've looked at with Astrape shows that there's very little interaction between wind and storage. There's data out there, literature out there, that kind of says the same thing. And given where

we're at on the solar proliferation, there's already all the benefit coming to the wind from where the net peak hours are.

So, the predominant interactive effect that we're seeing is between solar and storage. The wind ELCC at this point is almost independent, due to the way the rest of the system looks.

Member of the Public: Battery Outage Rates

How much do the battery outage rates impact the study?

Initial Response: PNM

We modeled them as an availability factor. So, the outage rates could have occurred at any point in time across the year. Holding everything else equal, if we had a 2% outage rate and, in the previous study, the maximum ELCC value theoretically could have been 98% for, say, a 4-hour storage device before we think about the penetration levels. And then this time, if we're modeling a 92% availability factor or an 8% outage rate, the maximum value that a storage device could see before accounting for those penetration levels is 92% instead of 98%.

So, you could think of it as a step shift downward in the starting point before each of the individual additional components that could degrade an ELCC over time were implemented.

Astrape continued.

That's it. You're basically lowering the starting point of where your storage ELCC can start. You're obviously from an LOLE perspective hurting reliability as well by having 600 megawatts of storage that now has a higher outage rate. Just like if I were to increase the outage rate on a coal unit or CT.

Member of the Public: Wind Over Solar

Is there any point at which you lower it [battery availability] well enough, it switches? That wind is better than solar for the system?

Initial Response: Astrape

I think generally we're seeing wind ELCC is higher than the marginal solar ELCC already.

PNM continued.

If we were just adding a renewable resource without any storage, from a reliability perspective, wind would be better. That doesn't necessarily mean it's better from a cost perspective.

Because we don't see the interactive effect between wind and storage, as we do with solar and storage, the outage rates would have to go up pretty significantly if we wanted to say, “Well, when would we start adding wind instead of solar plus storage?” That might be a better question.

Astrape continued.

Yes. I would agree with that.

Member of the Public: Curtailments

By adding significant amounts of solar, what's your level of curtailments?

Initial Response: Astrape

We can pull that. The model certainly will calculate that. They're definitely increasing. And definitely, as you add storage with the solar, you can reduce that. So, we could certainly show what the curtailment looks like.

Member of the Public continued.

Are we talking 30%? 40%? This a significant amount of solar over generation in the summer hours, the peak hours.

I would assume if you're not keeping up with the storage, you're going to have significant amounts of curtailment that you're paying for and you're not getting the generation.

Astrape continued.

Yes, and that should flow through the economic benefits that get seen in the expansion planning model; that should play into the economics.

We see curtailment more as an economic issue than a reliability issue. As we talk to solar developers out there, it does sound as though they have the ability to curtail. Obviously, that can be put in the contract. So, it's not so much a reliability issue as it is economics; You're paying for solar that you're not getting. And so, you'd want that to be captured in the expansion planning results.

But in 2025, [we'd have to check] we've got 1,500 megawatts of solar modeled. We have 650 megawatts of storage. So, imagine the storage is helping out quite a bit, keeping the number reasonable, if you will, in 2025**.**

PNM continued.

From PNM's perspective, there's still enough load in the summer, most of the time to where there's not going to be significant curtailments on the solar; [rather] more in those shoulder months. Peak solar production is really going to occur in May, because there is a bit of a degradation effect from the overheating of panels in the summer. So, you actually get slightly less output then, when you've got higher loads.

But we do agree curtailments will be more and more prevalent.

The degree to which there's going to be curtailments will also depend on how much our load grows and the storage that's added over time. To decrease curtailments by 1 or 2%, is it worth adding a significant investment in storage? That's a question, versus whether it's 10, 20, 30% curtailments.

I don't think we're seeing anything get up that high, especially in the near term. We're going to continue to keep an eye on it. And we've talked about some of the more nodal modeling capabilities that we're bringing in that'll help to pinpoint those curtailments a little bit more specifically.

But, as more and more renewables are added, there's going to be curtailments, there's no way to get around that. There's no way to deny it. It is an economic issue. And it's a cost trade off on whether it's more economic to curtail and potentially pay for curtailed energy versus make additional capital investment in storage.

There's no right answer. And from a contracting standpoint, there are ways to build the curtailments into contracts. And, ultimately, what that'll end up doing is leading to higher-price contracts if developers start building a certain level of curtailments into those contracts versus assuming that [the solar production from their facility] can't be curtailed.

Member of the Public: Adding Solar versus Wind versus Storage

I thought that adding more solar to the system was detrimental to it, or at least more detrimental than adding wind and storage. But from this presentation, I'm hearing the exact opposite. And so, I'm trying to reconcile what has changed from my [previous] understanding of it.

Initial Response: PNM

I think the way I would characterize it is that just adding solar by itself is going to have very little value from a reliability point of view to the system. It's marginal ELCC is very, very low. It may have some energy value to the system, depending on the price of that resource.

And when we model--we're getting back to the curtailments a little bit--the renewable resources, we either model them as a PPA, and say that even if you curtail the resources, you've got to pay for those

curtailments. Or if we model them as a capital cost, you're already incurring that capital cost, so you're not saving any money by curtailing them.

So, when we look at the economics that play out, you're really looking at the economics of the total cost of the resource or contract, not assuming that you save anything when curtailed.

And then thinking about the wind piece of it from a reliability perspective, in and of itself on a marginal ELCC basis, wind provides more reliability to the system, but there are going to be issues in getting that wind to Albuquerque, because there's not any available transmission, and it's going to take a long time to build transmission. It's likely we couldn't get transmission to deliver wind for seven years or so, [according to what our transmission group presented earlier in this stakeholder process.]

But when we think about solar plus storage, as long as we're adding reasonable proportions of both--and I think that's one of the key takeaways from the updated ELCC analysis--there is a sweet spot of a ratio of solar to 4-hour storage. Of course, that ratio is going to be different if it's 8-hour storage, or if you take the weighted average of duration on your system. Fundamentally, there's a sweet spot in the amount of solar that will maximize the reliability contribution of that solar plus a storage resource, and we just don't see wind providing that level of combined benefit, in and of itself, or providing similar synergistic effects when combined with storage.

That doesn't mean there isn't value to wind. A lot of the value that we see in our modeling associated with wind is not from a reliability perspective, but from a carbon intensity perspective.

So, for folks who are unaware, one of the things that PNM is going to have to start doing is demonstrating compliance, starting with the 2023 operational year (note that the [Public Regulation] Commission has not yet promulgated the rules on compliance), every three years, with Section 10(D) of the Energy Transition Act. PNM must prove that it is serving its customers with 400 pounds of CO2 per megawatt hour or less, on average. And that drops down to 200 pounds in 2032.

And a lot of what we saw from the wind piece of it is that wind is the alternative resource to overbuilding solar plus storage to start decarbonizing the non-solar hours.

And so, the value from wind may not necessarily be from a reliability piece. But it can be from a carbon emissions requirement piece as we have to dip down into that 200 pounds per megawatt hour. Because by the time we get out to that point, we're probably going to have so much solar and storage on the

system, the carbon emissions are no longer being created by serving daylight load, but by serving non-daylight load when you have natural gas on the margin.

If you think about it, the best natural gas resource out there is maybe 800 pounds per megawatt hour, if it's a combined cycle, or 1200 pounds per megawatt hour if it's a combustion turbine. And so, if I've got to serve an increment of load with a marginal gas unit, I'm going to have to offset that by anywhere from five to eight units of energy that is zero carbon.

So how do you best do that? That's where we're going to start seeing a lot of value to wind. Are we going to have the ability to do some type of pumped hydro or long duration resource that we can use to time shift significant amounts of solar energy into the off-peak hours? Do we have to do it with overbuilding shorter duration or mid duration storage? Or do we bring wind onto the system [since wind has a very different production pattern from solar].

And so, we have to think about all those different pieces.

Astrape continued.

To follow up, maybe the disconnect was overall value versus resource adequacy value. This story we've told as far as just resource adequacy values is pretty consistent and intuitive with what we've said in the past. So maybe it's more just the overall economic package. Obviously, the ELCC is a piece of that. So [perhaps] this is the disconnect.

Member of the Public: Future of Four Corners

Did you assume that Four Corners was in the mix in 2025?

Initial Response: Astrape

Yes, Four Corners is still in the mix, 200 megawatts.

PNM continued.

Yes. We have not been granted the ability to abandon that yet. So, we did not assume it was out.

NM RETA: Help from Neighboring Markets

Regarding the difficulties in hours 18 and 20, is the forum for where PNM goes [to purchase power] all in WECC or can SPP offer any assistance?

PNM Response

It's predominantly WECC. Regarding SPP: One of the other utilities in New Mexico, SPS, does have the ability to transfer power across the AC to DC converters at the Blackwater station and at another station. The problem there is that all the transmission is pretty well tied up and those converter stations are fairly unreliable.

So, the ability to count on getting some of that power scheduled across the converters and then actually deliver it to our load center is fairly limited. It is possible but it's not something that we would truly count on.

Transmission

KICKOFF MEETING: April 28, 2022

REIA: Interconnection Docket

Why doesn't your list of current events include the interconnection docket 21-00266?

Initial Response: PNM

Work on the interconnection docket is ongoing. A final order was issued in this docket on November 30, 2022. As of early December, it is unclear if there will be any petitions for rehearing or other forms of appeal.

We are reworking the interconnection manual, which, when done, will determine how the docket will affect the integrated resource planning process.

The interconnection manual and the interconnection process are governed by FERC and the Transmission side of the house within PNM, which is completely separate and distinct from the Generation group, where the IRP group falls. So, we have to keep a bit of separation in terms of what we would be discussing and what we would be thinking about in terms of interconnection and how that process works versus what we're doing on the generation side.

So, once a rule comes out, or once a change to the manual comes out, we'll see how we think that affects us. Ultimately, it's going to be a question of which resources are moved through that process and coming onto the system that we will have to ensure we account for in our modeling.

PNM Subsequent Comment

The interconnection manual updates rulemaking. We started this process to address two things: community solar and behind-the-meter rooftop solar. Community solar has a statutorily prescribed volume of solar additions to the system; we are absolutely going to include that in the IRP. Separately,

we have a behind-the-meter rooftop solar forecast, also planned for the IRP, which is developed without consideration of the effects of how quickly or slowly interconnections can be processed.

WRA: Regional Transmission Coordination (RTO)

I hope that one of the sub-topics of transmission will be the work that's being done around the West for regional transmission coordination (RTOs). What's being considered, by whom, and where? Is this an opportunity for PNM? Also, regional market opportunities because of what I've been learning is that for reliability in this age of increasing weather variability and penetration of utility-scale renewables, like we need a larger footprint, so I hope that's one of the sub-topics.

Initial Response: PNM

We will have to dive into the transmission topics in one of the technical sessions.

There are certain things that can be done within the IRP perspective, and unfortunately, there are things we won't be able to do, at least not in this IRP. Transmission is a regional or broader issue, and the IRP is required to look at retail and not even the full PNM balancing area authority present some complicating factors.

We could benefit from some type of regional transmission organization or other type of transmission operation to get to a full decarbonization, but we can't do that alone. PNM is a very small utility in the West, and that effort is something that's going to take more than just PNM to get the ball rolling.

WRA continued.

Regarding historically marginalized front-line communities, we may also want to consider the location of generation--whether it is for the jobs that would be provided or such.

See the discussion regarding sub-populations in Grid Mod..

PNM continued.

In terms of location, where we site generation in marginalized communities gets more into an RFP type situation, where you're trying to determine where specifically and what specific projects you are going to be adding. The IRP is more generic in that we look for trends. We look for how much, say, solar, wind, battery storage, and other things we are going to need to get the system right. You don't see the specific locations until you have specific projects offered in an RFP.

We are trying to figure out ways to improve upon that. Currently, we are working with some of our software developers to go to a more nodal production cost modeling paradigm so we can incorporate more transmission work and location-specific elements into the planning process. I don't know if we're going to get there through this IRP cycle. It takes a whole lot of effort to get those databases set up and those models calibrated, as well as trying to run nodal models.

You have to have very specific transmission elements to include in terms of locations, impedances, and other characteristics, and then you have to have very specific generator characteristics to include in terms of locations that would connect to those transmission lines.

So, we want to have the conversation. That's why we have transmission analysis in the IRP as a topic. It's much more complicated than most people understand. We are committing to do our best with it. We are being 100% straightforward, but we don't know that we will fully meet stakeholder expectations in this planning cycle.

Sandia National Laboratories: Transmission of Wind Resources

I was wondering if you're thinking that a discussion around something like transmission for wind resources may have a place in the transmission analysis group?

PNM Response

Yes, it has a place there. What we generally saw in the last IRP was that there was a tradeoff between wind coming in, around 2032, mainly centered around that reduction in the carbon intensity

requirements and needing to decarbonize the off-peak hours versus a lot of additional solar plus storage and trying to time shift the additional solar energy to the off peak.

The major hurdle on wind is transmission, bringing it in from the east and getting enough support to try to get that transmission built as well as enough support to have a large enough wind farm to enable that transmission. If we consider the most recent transmission line, the Western Spirit Line, that was completed and energized with pattern energy (it's not PNM--PNM is not an off taker from that project), they had to start that line five years ahead of when they started the wind farm.

So, we have got to get into a paradigm where we can look further ahead through our regulatory process and other things to take those proactive steps when we may not need the resource for another 10 years from now. We will definitely talk about that in the transmission planning aspects.

Also, from the transmission point of view, and maybe from the holistic system point of view, right now we have enough transmission to serve a load reliably. Assuming you can have control over all of your resources, as we move towards a paradigm where we have more variable resources and more storage resources, we're going to have to consider: Do we build the transmission system out enough to where you can deliver every single megawatt of renewables at the time it's produced? Do we accept some curtailments? Do you put storage both at the generator and in the load pocket? Or is there some combination of the three that enables the most cost-effective solutions for customers?

Yet another part about the transmission system design is that you have to figure out the most efficient way to utilize the existing system, and the things you need to add to that system to make it as efficient as possible throughout this transition.

TECHNICAL SESSION #1: June 8, 2022

Brubaker & Associates: Computing Limitations

The last time around you did some limited work when doing resource selection, allowing certain transmission upgrades or projects to be selectable in the optimization. Obviously, there are limitations on computing capability. Do you envision doing some of that this time around as well, [to the extent] it's workable and practical within current computing limitations?

Initial Response: PNM

We're looking at the lessons learned from that last go round. One of the things that we failed to anticipate was that, especially in some of the higher load cases, there just wasn't enough combined transmission plus resources, on an ELCC [Effective Load Carrying Capacity] basis, to meet those very, very high load cases.

Our transmission group is very busy, and we don't know if they are going to be able to provide us with additional candidate transmission. One thought could be, 'What do we leverage from the previous work?' Are there some ways to have another piece of it, like the MISO MTEP [MISO Transmission Expansion Plan] process, for example? They're saying, "What's in the queue? And how can we figure out different transmission solutions based on known projects in the queue?"

But then they're looking at adjusted production cost savings to look at the economic pieces of it. Well, if we've got generic resources, and not specific resources, trying to determine what the actual cost for those resources are, if you don't have an RFP, becomes a factor.

Can we go to the RFPs and say 'Well, we have these four zones, is there a way to come up with differentials and pricing and maybe production shapes for these different zones?' as opposed to being more generic? Then, that gives you a differential on both the transmission component and the resource component. But you're still only as good as those assumptions might be versus going to the actual RFP.

No matter what we do in this IRP, we're going to have to do a full transmission and production evaluation of an RFP in the future, so it's going to be somewhat duplicative work.

Brubaker & Associates continued.

We may have some information, at least ideas that were floated in Colorado about interactions between RFPs for resources, and what transmission projects are very well assumed to be available--how you factor that in. So, that might be helpful.

There were some concerns about the practicalities--some of the things that were uploaded in that study--and certainly some of our stakeholders may have similar concerns, so it may be helpful for you to share them.

PNM continued.

We'd be happy to take a look.

Of course, Colorado's transmission will be a little bit different than ours. But if there are lessons we can learn from their methods, we'd be happy to consider it. We—PNM and others--have been talking with Sandia National Laboratories about their research on integrating transmission modeling. It's a very difficult topic. The tough part is how to get this done in a way that actually provides value to the overall results and is not just nice window dressing.

Brubaker & Associates: Market Assumptions

How is transmission going to be worked into the IRP? What assumptions are going to be made about market support? What are the plans to tackle ELCC?

Update: PNM

See the discussion regarding market assumptions in questions asked at June 22, 2022, July 6, 2022, and July 27, 2022 meetings regarding Reliability, Resilience & Resource Adequacy.

TECHNICAL SESSION #2: June 22, 2022

Member of the Public: SPP Resources

If PNM is not connected to the SPP except through the Blackwater tie, how then can PNM take advantage of SPP/SPS resources?

PNM Response

Interaction with resources in the SPP [Southwest Power Pool] would be significantly reduced without the Blackwater tie. In recent years, interaction between PNM and SPP resources has been minimal. PNM also has ownership and capacity in the Eddy County tie in southern New Mexico could allow some ability to lean on SPP resources. This tie is at the end of life and options are being explored for possible replacement.

There are a few other AC to DC to AC converters between SPP and WECC that might provide limited power transfers between SPP and PNM. So, there should remain some very limited ability to interact with the SPP RTO, which includes SPS [Southwestern Public Service Company] here in New Mexico.

SPS, of course, is a subsidiary of Xcel and does have some resources in Colorado that we can potentially interact with PNM directly or indirectly through converters located in Colorado. But that's expected to be very limited and typically our interactions with other utilities are to the west of us not to the east

TECHNICAL SESSION #3: July 6, 2022

Member of the Public: Transmission of Wind versus Solar

Is transmission also an issue with wind that may be less of a transmission issue as solar?

Initial Response: PNM

The transmission issue with wind is predominately related to the fact that there's not really the ability to add wind resources anywhere near the load pocket. And so, when we think about where the good New Mexico wind resources are, they're all out in the eastern New Mexico, Clines Corner, and further east. The transmission coming in from that part of the state is fully subscribed.

In order to get more wind into the system, we wouldn’t need to add more transmission, where the general geography and availability of solar allows for different resources that have solar resources to be added differently throughout the broader part of the state. They may not require transmission. We're getting to the point where the transmission system overall is pretty fully subscribed when you talk about firm transmission service.

And so there may have to be a different way of viewing the way that the transmission system is going to be used and operated. Maybe we need to start looking at energy only interconnects, where you allow for some curtailments, or you got to start putting the storage resources in the load pocket as well as having the resources be able to soak up some curtailments that might occur in order to use the transmission system as it currently exists without adding much more transmission.

It takes a long time to add transmission to what our transmission group will typically tell you; we've got to go through the standard process and build a new 100 mile or 150-mile line, and you're probably talking about a 10-year project from start to finish--from conceptualization, permitting, commission approval. and then actual construction.

And so, all those things we have to factor into the equation. Many think that transmission is going to be something that can get us over the hump of decarbonization. But unless we can build transmission

faster, we might need to focus a little bit more on distributed resources until we can get that transmission built.

Member of the public continued.

I was aware of that, and it's always been a question of a concern for me--that transmission building doesn't seem to be a very immediate resolution to anything.

PNM continued.

Yes, you're exactly right. And we would like to be able to build more transmission and upgrade our existing transmission system and the backbone structure. The main PNM transmission lines were all built back in the 60s and 70s. We think that it would be prudent to add more transmission upgrades. The reality is that it's very difficult to do from a regulatory, permitting, and other process perspectives. Just because we want to do it doesn't mean that there aren't impediments to getting it done.

InterWest Energy Alliance: Transmission Analysis

My understanding is that PNM is looking to link transmission to a particular resource in a particular location, and then ascribe the costs to that resource or development or whatever? Is that right?

PNM Response

The IRP is not a full-blown transmission analysis, and it was never meant to be one. There are things that we can do and things that we can't do.

We addressed transmission hurdles in the 2020 IRP, where there were four candidate transmission projects: one that would increase transmission capability from the Four Corners area, one that would go towards eastern New Mexico, one that would go to northwestern New Mexico, and one that would go south of Albuquerque, but not across cut Path 47 into the southern service territories. We had costs for those such that we knew what resources could generally be added in those different resource locations.

For example, when we would only assume what was available in the east, we said that to do that 800-megawatt transmission line had a cost of, say, $300 million, or X dollars per kilowatt of transmission. And then we would add those X dollars per kilowatt of transmission on to the dollar per kilowatt for wind. And so, the combined cost of the model would show that when making that choice to add wind it was a combination of transmission and capital for wind.

And we said that for wind, in particular, if you're going to have to build that whole big new line, you're not going to do it for less than 400 megawatts. So, we made an assumption that you had to take at least a 400-megawatt wind farm with half of the transmission line, essentially. And maybe there was some other party who would take the other half of the line that wouldn't go into retail rates.

That's another distinguishing feature about the transmission piece: We only look at New Mexico retail in the IRP. All of the transmission that PNM owns and what is in our balancing area authority; half of it is not used to serve our retail system.

So, you have to think about the things that are affecting the transmission system and how that would work when only half of it is actually utilized for the transmission of energy for the retail customers and only half is cost recovered from retail customers. The other comes from FERC jurisdictional.

InterWest Energy Alliance: Transmission Constraints

PNM, having acknowledged transmission constraints in the east, why not look at those as individual pieces of the IRP as well, instead of just linking it to particular resources?

PNM Response

This question gets into the difference between PNM retail and then PNM the balancing area.

The eastward constraints are because we have, aside from needing additional transmission, to bring in resources, say from the east, for new wind. If we wanted to go further east than that, we're up against the AC to DC to AC converting stations that interconnect us into the eastern interconnect. They're on a different frequency; they're asynchronous, essentially, to the PNM system. In order to transfer power between the eastern interconnect and the western connect where PNM is, that power should go

through these AC to DC to AC ties, which are very old and not very reliable anymore, and would require significant upgrades in order to allow for greater deliveries.

Once that power gets across the ties, there are additional constraints then to get the power from across those ties to the PNM load centers. There really is a need for us to increase those ties and increase that transmission versus adding resources elsewhere.

The same thing could be said about going up towards the north, but that would all be power that's coming in from neighbors. Are we going to be able to count on that? Are we going to be contracting for long term obligations that would necessitate those transmission additions? And would that be cost effective, rather than building resources closer to our load center, and being able to control those resources

The IRP really is not the right process for assessing that.

Given that there are these fundamental differences between the way the PNM retail system works and how we plan for that versus the way you might think of doing broader regional transmission planning through an RTO, is one of the keys that will help us get to carbon free. But it's not going to be PNM that drives that process. We're just too small of a fish in too big of a pool.

NMPRC: Transmission Constraints

Is a decent summary that you are largely approaching these transmission constraints in the IRP by planning for large projects, a couple of 100 megawatts where one or two developers will serve as a kind of anchor customer that will take responsibility for the transmission upgrades needed for their projects?

PNM Response

You might infer that somewhat from the wind example. But generally, we're just looking for trends in the IRP. When we get into an actual procurement, we will identify the specific resources and then apply to the [Public Regulation] Commission.

In a countervailing example, when we are looking at storage, or solar things that can be built much more modularly and added closer to the load pocket, we didn't require a minimum 400-megawatt size. There were different transmission options: For example, there was a transmission option looked like it could upgrade the load carrying capability just within the load pocket. And then there were two or three transmission options that were in the west and the north and a little bit in the south.

And because we see much more difference in size on solar and storage, we said that those could be picked up in much smaller increments, and so might marginally add some transmission upgrade costs, but in proportion to the size that was chosen for that specific resource type.

The IRP might say: In X year, we need only 25 megawatts of solar and storage at this location. It would only incur a transmission upgrade cost that was proportional to the dollar per kW cost of the transmission that was associated with the north or west, which was a lower cost than going to the east, but it didn't require that big hurdle in terms of a 400-megawatt size.

That's what we've been seeing in the RFPs as well. There's some work that can be done within smaller time frames. If you start adding those really big resources--200-, 300-, 400-megawatts--those are going to drive significant transmission upgrades. We'll get to a point where everything will drive that, letting you know that the transmission system is getting pretty fully subscribed.

There are little things that the transmission group can do to accommodate some smaller resources, but eventually we're going to run out of those and it's going to drive larger transmission upgrades.

TECHNICAL SESSION #5: September 13, 2022

NM AREA: Ordering Paragraph B

NM AREA will be most interested in PNM's specific plans for its 2023 IRP to meet Ordering Paragraph B of the Commission's July 25 Order.

PNM Response

We're going to start talking about transmission modeling in the IRP generally, what we see across the country as well as specific events we'll be doing,

Paragraph G of the Commission's July 25 order, and the 2020 proceeding, is not part of the ordering paragraph.

The ordering paragraph's particular section is Section B, which recommends we include a meaningful analysis of transmission and distribution constraints as well as see what other new requirements may come out to new or amended IRP rules.

We do know that there is an IRP rule scheduled for discussion, potentially a final order will come out of that in [the September 14, 2022] open meetings. We'll have to wait and see what that says.

You were focusing on the ordering section, and we will evaluate any new rules that come out then or otherwise that we have to take into account.

Member of the Public: FERC Withdrawal Penalties

Are there withdrawal penalties for applicants?

PNM Transmission Response

They're not necessarily withdrawal penalties, but there are obligations for study costs, to continue through with study costs, and it will just double their study cost requirements as it stands today, but not any "withdrawal penalties."

Member of the Public: Target Audience

To whom are you targeting this information? Is this to the general public or is this just specific financial interests? It seems that the general public is not very well informed about much of what was covered today.

PNM Transmission Response

That's probably true but we try to get the information out through our open access website. Normally, the public is interacting with our site, where we have published every study we've ever done on the transmission system. We have all the information that's required out there. Folks can get a great feel for our system. I'm surprised at how few people use it. To remain in compliance with the federal rules, we make all information about the transmission system available to all parties, identically, and at the same time. That is a federal obligation.

So, this information would be available to the general public, on the internet.

InterWest Energy Alliance: Proactive Transmission Planning

Back to the chicken and egg problem. I want to put in a plug for proactive transmission planning.

We've encountered this problem for a long time, and we found that the only thing that works is proactive transmission development. You know the CREZ (Competitive Renewable Energy Zones) example was kind of the first one that did this. At that point, it was kind of the risky and novel idea that we are going to designate these zones, we know where renewables are, and we think they'll develop. And they did. We built it and they came.

We've seen it replicated in SPP and MISO with the MVPs (Multi Value Projects) and [in California]. All these examples we've seen have been very successful. And given where the renewable cost trends are with the IRA tax credits, and most importantly with New Mexico state law basically specifying where your generation mix is, it seems to me there's extremely low risk that you would build transmission to these high real resource areas. And we know where these are, and the renewable resources are not going to change. We know where the wind is and where the sun is. It seems almost no brainer that if you were to build transmission, proactively plan transmission to those resource areas, maybe informed by projects in the queue, and even do some type of public season process where there are some deposits, some skin in the game, from developers to ensure they are real. That's been used in other regions as well.

I'm very confident this would work and get you much more cost energy at a lower cost of transmission because you could right size it to accommodate the scale of the project for one interconnect that you need to meet your load. Basically, you can do proactive transmission planning and incorporate this into your process. I think that is essential for doing this cost-effectively.

Initial Response: PNM Transmission

Yes, I think there's no question that you're correct. And that's one of the things we're looking at is trying to do a longer-term transmission plan. And again, a transmission plan is only as good as where did loads decide to go and where did the generators decide to go?

We've talked about doing this internally and we haven't been able to execute it quite yet, but one of the ideas we're knocking around is exactly what I talked about a little earlier: trying to break a system up into zones. One of the things we've been cautioned on is, as a company, creating winners and losers in the state. And so, we'd have to figure out a way to do that collaboratively with stakeholders and ensure that we're not discriminating in any way or creating some kind of disincentive for economic development in parts of the state that might not be on our top five or top ten list in terms of locations.

But we're working through those conversations to try to figure out how we might go about doing something like that because, again, we see value in that potential.

InterWest Energy Alliance continued.

Great, thanks.

PNM continued.

To follow up on that a little bit.

The example that you gave--CREZ--might have been legislated for that development, and the MVP projects and other things went through the RTOs. There's just a different planning process, different cost allocation, and recovery mechanisms that are set up.

PNM is a smaller utility. A half a billion- or billion-dollar line is approaching 25% of our total market capitalization as a holding company, not just even looking at PNM utilities. So, it's a difficult proposition. Unless there's some other way to gain additional financing, to try to stand up some of those things on speculation and take the risk when regulators have been looking for ways to write us off.

PNM Transmission continued.

The way we talked about doing it is trying to put the information out there so people can organize around the information. So, instead of us deciding--please come and give us a chunk of money to help us make it happen--It's empowering people with information about economic feasibility, permitting feasibility, and constructability incorporation in the broader system. Those kinds of things are what we'd like to arm people with, rather than trying to be at the center of taking a risk.

For transmission, for example, SunZia is somewhere in the $2 billion range. This company doesn't have $2 billion to invest in a project like that today. The kind of thing we would hope to do is this idea of arming people with information and helping the market to organize itself.

Sandia National Laboratories: Transmission Rate Base

When an interconnection is made for a specific generator, how much of that cost eventually goes into the transmission rate base? It seems like some facilities could be useful for interconnecting more resources and others might be only used for that one generator.

Initial Response: PNM Transmission

Yes, there are not going to be a lot of instances where a transmission line is exclusively for one person, unless it's like a DC line, where you can control those flows. Anytime you add a pipe to this system, the physics will be that those electrons will take the path of least resistance and those electrons may flow if there's an outage on some other part of the system.

Now, that new addition that we get for this network customer is useful to keep the system going. So, in an interconnected transmission system, we can't think of any scenarios where the transmission would not have a benefit to the broader system.

Sandia National Laboratories continued.

I'm wondering why, if it's just a radial line, you've got a solar facility and you've got a single radial line connecting it to the transmission, then you wouldn't expect any flows on that line, normally, right?

PNM Transmission continued.

We can't think of an instance where we've built a radial transmission line. There are radial generator interconnects, which is a different situation. We don't build those generator interconnections. Those generator interconnections are part of the generators because it's only when they get to the switching station, or substation, that we built to integrate them into the transmission system. And then everything is downstream from there. That's been these costs we're talking about.

InterWest Energy Alliance: Transmission Investment

Are you thinking in terms of incentivizing developers to focus on particular areas just to be more efficient with your dollars? Are you thinking that you will be focusing some investments yourselves to enhance the interconnection opportunities in particular areas, to kind of create the hot highway and they will come and focus on those particular areas?

PNM Transmission Response

We would love to be able to do that. [We will address the chicken and egg issue later in this presentation]. We know people don't like chicken and egg kind of problems. But we have a hard time going to a commission to say, “I need a half a billion dollars to build a line that I have a specific order generator to go with.” And vice versa: There are generators and loads have a hard time getting interconnected if they don't have something to go to, or they now trigger a seven- or 10-year, half a billion-dollar event.

So, it's this quandary that we're in right now. Our planning--you're seeing this on the resource adequacy side--is this: This issue is driving the fact that we're building resources just in time and just the right amount for just the knowledge we have today, rather than doing what we've done historically, which is kind of going long.

But our regulatory paradigms don't support that because we might be wrong, right?

Say, we invest this half a billion dollars in flows, and the generators don't go where we set them. Now, we've put half a billion dollars of customers' money at risk for maybe not the payoff we thought we were going to get. We doubt that would happen. We think if we build it, they would come. The hard part

is getting those folks who need it to give us that money to agree to do that. Speculatively, that's the crux of our issue here.

InterWest Energy Alliance: Transmission Options

Am I to understand from the previous few slides (Slides 30-35) that these transmission options are all selectable in the IRP model? Can you describe what is selectable in the IRP model?

PNM Response

We cover later in the presentation some of the things we've looked at in terms of modeling transmission, the IRP, some of the limitations, and where we think we'll be going.

The short answer is that these are all looking at delivering resources to load. And the way we were looking at them in the last IRP ultimately was through the use of transmission cost adders, not looking at a specific representation of this in a pipe and bubble or other fashion.

PNM: Permitting

Can you provide any color around the cost of the permitting/CCN labels on here (Slide 30)? The cost last time was obviously lower than this when we looked at it, a couple years ago in that IRP cycle. Is the permitting and CCN timeframe there five years, is that the entirety of the process or is there additional time on top of that for construction and other things that need to be done?

PNM Transmission Response

Typically, there would be more time on top of that for construction, potentially a couple of years on a project like this. For this one, the permitting is potentially not too complicated at this point, so that five years may be a conservative answer for this particular edition.

In most cases, and a lot of the transmission we look at, that would be not at all conservative. We would expect to actually run into longer permitting times. The five-year total project is probably not unreasonable.

We're actually laying some groundwork today to try to make sure something like this could be built in the future. And the cost there is much higher than it was the last time. I think we're more in the $40 to $50 million range. But that's just factoring in what we've seen happening this year.

InterWest Energy Alliance: Integration to the West

[Concerning AC/DC projects], is it in our interest, is PNM having discussions, particularly with Sun Zia, about essentially integrating the eastern end of that into the New Mexico system so that you take advantage of load diversity with other parts of the West, particularly, areas to the West--most notably California--that have built a lot more solar?

There's a lot of cheap generation available during most of the afternoon in New Mexico that could flow west to east along those lines that maybe wasn't envisioned 10 years ago when those lines were initially sketched out. Is that something that would be of interest, is PNM exploring, potentially making some of those lines network elements?

PNM Transmission Response

That is a question that’s been raised internally. The hard part, again, is the capacities they are proposing. There has to be some kind of redesign scenario to make them useful for what the system could off peak. For example, the size of Sun Zia would absolutely overwhelm, and we'd have to figure out some way to get it up to where the load serving capability is.

We have spoken with and are working quite a bit with Pattern and Sun Zia from a logistics perspective and looking to share easements and in some cases to share colocation and those things. In those discussions, there hasn't been an interest at least in operating up interest in it. And number two, on the size of it, we don't know how it would be incorporated given existing plans because it would absolutely overwhelm the system and not be able to be incorporated without conditional changes to our system.

PNM: AC DC Cost Increases

You've given some of the significant cost increases related to the repair of the AC DC converters. It may have doubled from the last time those were estimated, or something to that effect. Do you have an idea

of what the cost of doing these lines today would be as opposed to when they were done just a few years ago?

PNM Transmission Response

We have seen cost increases. As an example, year over year, steel prices have gone up 92%. Transformers, poles, conductors are all ranging somewhere from 40 to 60% more expensive year over year. So right now, is not a great time of stability.

Price volatility is out of control--probably somewhere at 60 to 100% more expensive to go in today. [Current supply chain and potential labor issues may be contributing factors in the future.] These are unprecedented cost changes, at least in the last 30 years.

PNM: Interconnection Costs and Network Upgrades

Are there interconnection costs that are network upgrades as well?

PNM Transmission Response

Yes, the majority of interconnection costs generally become part of the network upgrades as defined by FERC. There's a portion that's always dedicated to the specific developer in the interconnection process. And the rest is considered an integral part of the transmission system, although it also becomes part of the generalized transmission system and rate-based.

PNM: Resources Without Defined Customer

For resources that come online that do not have a defined customer yet--they're building and they're assuming that they will find a customer once it's built--how are we studying the network upgrades that may be required?

PNM Transmission Response

That's an interesting question. Typically, we really haven't seen that situation too much because most of them, if they don't have a customer yet, will not move forward. There's too much risk for them. The banking and the financing system almost mandates that they show who's going to be paying them revenue for a project.

So, it's not usual for us to actually have somebody move forward with a resource and not have a clearly defined customer. But if they did do that, we would not really be able to start without them telling us where they want the power to go. And if they haven't done that, then we don't even offer them what we would call firm transmission service. They always have to tell us at least where they're going to take some power in order for us to accommodate them from a transmission service perspective.

We do have some resources connected that have short term customer obligations, but from our perspective, they've arranged transmission long term with us to points on the system.

Member of the Public: Developers' Responsibilities

Do these developers have any responsibility for what they do to the system? They put their generation unit out there somewhere with a big wind farm. They put in the generator tie, and then they don't care what happens? Are there no controls?

Initial Response: PNM Transmission

The FERC processed define the controls that are there. For the most part. They have to go through the FERC OATT (Open Access Transmission Tariff) process to get interconnected. There's a significant amount of risk that's put on them initially if we are going to be constructing facilities to accommodate their requests.

There are two primary things there: the interconnection facilities, which get defined in the generator interconnection process, and then there's potentially network upgrades to move the power from the point of interconnection to a customer or some other point on the system that they've requested. So, there are potentially two types of costs we can run into in terms of accommodating that request.

The developer is on the hook to fund those upgrades initially upfront. Of course, if they take transmission service, they do pay for a portion of the transmission system as a result of that. So, they have a lot of risk from that perspective. If the project were to fail, and they didn't complete it, they

would be out the money because we had pretty much collected from them as we build. In the end, FERC requires us to refund that money back to them, provided their facility is fully up and it becomes commercial.

There's risk on the front end for them for sure. They have to carry security on everything from the time that they enter into an LGIA (Large Generator Interconnection Agreement) until the time they actually move forward. They are carrying security on the construction costs we could incur.

PNM Transmission continued.

In no case are we interconnecting something that would cause the system to not be able to maintain its compliance with reliability standards. That's the purpose of making sure, if we need network upgrades, that those upgrades are there to make sure no one else can be harmed.

Member of the Public continued.

So existing customers are essentially protected, and the system is essentially protected. But that gets back to the point you made previously about storage, which clearly becomes part of this conversation at some point.

PNM continued.

We are protected up front from the financial risk, where you are ensuring safe, reliable operation of the system, but those additional interconnections can change. As we've been talking about the flows, the way the system is operated, redispatch of the system, all within the normal operations allowed for by reliability standards.

PNM Transmission continued.

And the cost of the facilities does become part of the transmission rate base. It's not specific to any entity once it's been refunded. Generally, there may be some exceptions to that.

PNM continued.

So, the network upgrades, not the interconnection costs, after being refunded back to the customer, would then be flowed into the overall transmission revenue requirement, jurisdictionalized between FERC and retail customers, and could lead to cost increases that were not necessarily in support of the retail customers' own request.

PNM Transmission continued.

That's correct.

PNM: Interconnection Points

Do you have a thought why most of these interconnection points (Slide 26) are situated along the major transmission corridors?

Initial Response: PNM Transmission

Most developers recognize that they have to get to an interconnection point with a transmission system. When they start looking at the fact that it's their responsibility to get to a point on the existing system, that becomes cost prohibitive if they're too far away. A lot of them are pretty savvy about trying to be as close to existing interconnection points as they can be.

PNM continued.

Because they don't want to trigger a large generator tie or a significant upgrade on the transmission system that would either take a long time or create a large cost burden?

PNM Transmission continued.

Right, it creates both a permitting uncertainty, you end up involving a lot more types of lands or landowners if you have to build a longer generator tie, and of course, the longer it is the more cost there's going to be.

InterWest Energy Alliance: Off-Peak Periods

In your in your off-peak period, where you've got high winds, high solar, you've got substantial flows to the northwest, are those off-peak periods times at which some of our neighbors to the west, and I'm thinking in particular California, they might still be on peak, or that they have higher needs that we can fill? I'm wondering if that occurrence can help us with some geographic diversity enhancements and filling neighbor's needs, when perhaps we have excess during these off-peak periods.

Initial Response: PNM Transmission

We are allowing the EIM (Energy Imbalance Market) to dispatch our resources inside the scheduling hour to address those kinds of things. The EIM is taking place in real time to do that very thing.

PNM continued.

Though, if there's high solar output on our system, there's also high solar output on the California weather systems.

PNM Transmission continued.

You might see negative prices in the market.

InterWest Energy Alliance continued.

That's what I was wondering. How much of our off-peak excess, shall we say, can benefit the West? Or not?

PNM continued.

A lot of the wind resources we talked about--that 2000 MW, that 2500 MW--was in the eastern New Mexico areas already flowing towards California, scheduled into there. The power is going to flow inversely proportional to the impedance of the system. And then we've got to re-dispatch our generators in order to manage the contractual pass as best we can. And those create those inefficiencies.

PNM Transmission continued.

Internal constraints in New Mexico are potentially limiting the ability to get that excess to another party. We're putting so much capacity into renewables that it exceeds what the transmission system is capable of – internally to the state. If you can get that to market, somebody could probably use that. The other big message here is that that characteristic plays a role in where and how much storage you need to help manage the energy picture.

PNM continued.

Those new flows are specifically a direct result of these non -PNM retail customers taking service under the Open Access Transmission Tariff to develop projects and move that power out to the west. And within a retail-only snapshot that would not be identified, but that certainly would have significant impacts on how you would design the retail system or any changes to the overall network given those third parties.

PNM Transmission continued.

That is a big part of it, but the other part is that even to serve New Mexico load, we build renewable capacity that at times will dispatch well above the level of the load, which means it's going to go somewhere else. When you exceed your load in New Mexico and you're generating more it's going to flow out. It's a combination of the two that leads to this scenario – you have a lot of capacity being built for renewables and it can simultaneously all generate, or close to all of it generate, at the same time.

Member of the Public: Non-retail Users

How much do you anticipate that some users, perhaps even the non-retail users, which are perhaps [a] larger [segment], would peel off and become kind of separate independent nodes of their own to do their own power generation, solar with battery backup, things like that, and how would that impact the need for transmission?

Initial Response: PNM Transmission

A lot of wholesale transmission is entities that are completely independent of PNM. They typically are interested in selling resources to a customer somewhere. But you really can't peel off from the transmission system. Everything kind of flows, the way it's going to flow once you inject their resources. They do pretty much define what resources they put in and how much energy storage they might have.

It's really up to the developers to decide what generation project or portfolio they want the transmission system to address.

PNM added.

As we understand the question, were you asking how might potential changes in the transmission system be recognized given customers' personal desires to add their own generation, especially storage, and, would that change how might the design of the transmission system be effectuated in the future?

Member of the Public continued.

So, it might be the non-retail version, which we're not really dealing with, which we find a little bit concerning. It's helpful to have this presentation to get this bigger picture. But, when we're talking about the IRP, per se, it is concerning that these other factors can be such drivers. And it's hard to understand how that can be controlled very well.

PNM Transmission.

That is the crux of the challenge. That is what keeps us up at night. It really has been a challenge – FERC opened access to the transmission system in the 1990s. It is effectively wires available to anyone for any reason as long as they meet federal obligations, they get their piece of the pie. That is a federal

regulation – not something we've developed or decided to do independently. That is the way the US grid is set up today. That is the thing that really makes things difficult on the retail planning side, given the volume – the Western Sprit project that went in this year, 100% of that is going out of state, but using the transmission system in New Mexico to do it. And that is allowed – that is what the rules say. You are picking up on the core issue here, it makes this IRP process very difficult to give a good and complete picture of the transmission system when it's focused on simply retail and one element of the transmission system.

PNM continued.

We don't have any control over what the third parties are doing. And, hypothetically, if we were to look at just a retail snapshot of loads, resources, in the transmission system, it's possible that we could identify what could be perceived as a transmission solution that would help our retail actions.

But the presence of the non-retail customers and their utilization of the system and their own future interconnection requests could nullify any benefits potentially of some only-retail look at the transmission change, right? But one of the things is that if you don't look at the whole picture, you're not really getting the full solution.

PNM Transmission continued.

This is not new. In New Mexico, we've always had a substantial amount of power moved out of state—one of the big changes, particularly out of the coal plants up in the Four Corners area, and to a lesser degree with the gas down in southern New Mexico.

So, energy moving out of state is not unusual. But the location of the energy moving out of state today is very different. It's in a very different location than those coal plants were. It's loading the transmission system in a very different manner.

Member of the Public continued.

I just continue to be concerned [about] the changes in the industry overall. The grid is 115 years old, or something like that. Really not very old, in the grand scheme of things. We're trying to look into a crystal ball that's pretty cloudy, looks like to me.

PNM Transmission.

Yes, that's a good way to put it. It's hard to know what the perfect solutions are. We think that's the hard part. There probably won't be a perfect solution but we'll be trying to achieve reasonable solutions. When time passes, your vision will be 20/20, and it's not that when you're trying to make those investment decision in advance of what will ultimately transpire everywhere.

InterWest Energy Alliance: Cost Allocation

What about the thorny issue raised of cost allocation? Do you plan to provide input to FERC on that? What's your view on that issue?

PNM Transmission Response

Cost allocation has been the thorniest issue. Not everyone's aware of the Desert Star effort in the 90s to create an RTO (Regional Transmission Organization) in the West. And it seems that cost allocation is still a significant issue in the West. It's the thing that holds us back collectively as a group.

We're very anxious to see steady results on our RTO, very anxious to participate and be part of the solution. But not everybody feels that way. We've seen a lot of the attitude of: if even $1 changes in my equation, I'm not doing it. This, despite the potential improvements in efficiency and reliability. So, it's something that we're continuing to work. We have a manager who handles RTO participation.

And through the EEI (Edison Electric Institute) we are participating in those pieces of cost allocation that are part of the FERC NOPRs (Notice of Proposed Rulemaking). We must collectively come to some solutions here because there are a lot of efficiencies to be gained, as we saw in national studies, and as we know empirically through the success of the EIM (Energy Imbalance Market). There's really something to be gained here.

InterWest Energy Alliance: FERC Process

What kind of input have you as PNM had into the FERC process? I know it's early days, but what do you anticipate contributing into that, the FERC consideration of its rules?

Initial Response: PNM Transmission

We're participating in the EEI, the Edison Electric Institute, the consortium of utilities across the U.S. that meets and puts together responses to federal and other rulemakings or policy issues. We are participating in the EEI processes to provide that on a broader basis. I think there's certainly value in contributing individually. But I think there's a much stronger and better voice to come through a more organized and well thought through approach that will participate in the EEI comments.

InterWest Energy Alliance continued.

Can you share with us what are the objectives that PNM would like to accomplish? Or what's the message that you all want to send on these issues?

PNM Transmission continued.

There are some significant flaws in the open access transmission tariff process [because] when it was designed, it never contemplated the energy transition. And the rules reflect that. The rules are really why you see backlogs of multiple years in not only our queue, but in some of the ISOs who have applied to have a period of no study or no new requests, because it's been so overwhelmed.

So, the system is completely overwhelmed by the volume in the energy transition, making it pretty ineffective. We are very excited about some of the points that are being contemplated in the FERC NOPR (Notice of Proposed Rulemaking).

I'll give you an example: withdrawal penalties. It is one of the things that really slows the process down.

Generally speaking, folks get into the queues just to see. And when you see the volumes of folks that are coming in holding up these processes just to see, it is a really stagnating development. It is really a problem. And most folks end up withdrawing either after the first round of studies and the second round of studies, which then triggers a required re-study of the entire cluster.

We had 11 withdrawals and ended up with four rounds of re-study in each of the study processes. You can imagine that at 150 days a pop at least, that really puts things behind.

So, I'm quite excited about the FERC NOPRs. There's several of them out, but one of them is related to the whole process. Very happy to see some of the changes.

Interestingly, I'll note that some of the things that are being proposed in the FERC around the OATT (Open Access Transmission Tariff) are things we're already doing. We already do cluster studies. We already allow for multiple requests to be interconnected on the same interconnection.

There are a number of those, what they're calling "reforms" that we have adopted already and did years ago. So, because of the overwhelming interest in our queue, given our wind and solar potential in the state. Necessity is the mother of invention here. That's the route we've taken, and it seems that FERC is directing the rest of utilities in the U.S. to go that same direction.

PNM: Third Parties

In terms of all these other customers accessing PNM's transmission system, whether to try to incorporate resources for PNM's use, or to ship out of state, any of those that are not dedicated to PNM retail still affect the way the transmission system is operated. All the interconnection requests that PNM Transmission does from the federal Open Access Transmission (OATT) standpoint really is the primary driver in the manifestation of changes, investments in the transmission system. Is that fair?

Initial Response: PNM Transmission

Yes, certainly the other customer usage is a very key driver in how we try to expand the transmission system and operate the transmission system. All of their needs are factored into operations and scheduling of the system on every day of the year. Today, we have to manage that every minute, every hour, every day, making sure that the transmission system usage has been indicated and that it's clear that that usage is within limits of the system.

PNM continued.

And we've got no control over what those third parties are doing from a PNM retail standpoint. But from the transmission unit, you have to accommodate each and every one of those requests, just the same as PNM retail use. It's 100% equal an open access to all.

PNM Transmission continued.

That's correct.

PNM continued.

We want to make sure folks are following along and hopefully start to understand a little bit of the differentiation between PNM the utility, PNM the transmission company, the open access transmission tariff, and PNM the Transmission Balancing Area. These are not all one and the same thing. They all are governed by different rules and regulations and different ways things must be looked at from the retail versus the FERC point of view.

PNM: Existing Resources

Today, given the resources, the loads and the rights that we have, is there much of any more resources that can deliver into southern New Mexico to then be transmitted up to the northern load centers?

PNM Transmission Response

There is potentially still some ability to do that. We tend to look at them on a case-by-case basis--where they're located exactly in southern New Mexico can make a difference. And PNM itself would have to acquire transmission capacity from another provider to move additional resources from the south to the north.

So, we would look at what we can do within rights in the south. What can we acquire from another provider in the south and then what can we provide acquire to move from the south to the north?

PNM: Existing Resources

The existing resources in the eastern part of state, the 2,457 megawatts--it's probably about 500 megawatts that's actually contracted or delivered for PNM retail and the rest of it is wholesale being shipped out of state, or something to that effect?

PNM Transmission Response

That's correct. We're subscribed to about 500 megawatts of those wind resources.

NM AREA: 2023 Additions

Are the 2023 additions for 840 megawatts (Slide 22) additions that are based on the latest updates from PNM to the Commission. that is, the resources that are actually expected to be in service in 2023? Has that been updated to match this number in line with that, or is it a different number?

Initial Response: PNM Transmission

It should be in line with that. It represents some of that--it's still got some uncertainty around it, but it represents the 300 MW between San Juan Solar and Rockmont, the 300 MW Arroyo Solar, and the 190 MW of Jicarilla Apache Energy Center that was looked at as a Palo Verde replacement. It's pretty much what's in that 840 MW number and it includes the 50 MW of Jicarilla I.

PNM continued.

I think a better way to express this is from the transmission interconnection or large generator interconnection, this would represent those still active requests associated with the resources that have been approved.

PNM Transmission added.

Yes, it represents the resources that had been approved.

NM AREA continued.

Alright, so the dates on this don't necessarily line up with the latest expected in-service dates.

PNM Transmission continued.

That is certainly possible.

NM AREA continued.

Or the latest ESA (Energy Storage Agreements (ESA). It is like there's a pending expansion of the Atrisco Energy Storage Agreement, for example.

PNM continued.

That does not change the interconnection size. so, it wouldn't make a difference on the size here.

NM AREA continued.

You're right. I was forgetting that point. But the dates here don't necessarily line up. These are more based on the proposed interconnection dates, or approving your connection dates, but not necessarily latest status and projects, right?

PNM continued.

I think that's fair. This is still the work that these developers in their contracts, as a provider of the Commission, and standing in the interconnection queue, will be working with the Transmission Group, insofar as trying to get those interconnections finished and delivered by those time periods.

As we're continually updating the Commission, some of those things will change. But this does paint a pretty realistic picture of some of the changes that we will be seeing on the system over time.

PNM Transmission continued

Just recognize that some of those resources may not be in 2023. It may be after that, but it does try to tie it back to what has been previously approved.

InterWest Energy Alliance: Manchin Bill

I just wanted to chime in that the Manchin Bill is currently still being drafted but drafts that are circulating include a cost allocation measure that would allow FERC to determine cost allocation for transmission. And so, I think that is improving some obstacles, certainly for DC lines.

But I think cost allocation is one of the biggest obstacles for significantly sized transmissions because it benefits large regions. It's certainly a national network like this, which allows FERC to do that. There's also a parallel FERC effort looking at transition planning and cost allocation. So, there is federal action that is going to help on some of these issues.

PNM Transmission Response

Yes, there is a lot of activity. And first, we'll talk a little bit about that to try to ease some of the dilemmas from the inherent problems with the process today. That will help all of us.

InterWest Energy Alliance: Major Investments

I have a question about your opinion about [Slide 15]. I see a 35-year study window here, and IRPs generally look at a 20-year study window. [Do] you believe like I do, that since transmission is such a long-term investment, IRPs don't really fully capture the benefits of investment, similar to the way that this study in front of us does?

Initial Response: PNM Transmission

Yes, I would totally agree with you. And we're going to talk a little bit about the dilemma of how our FERC rules and the FERC process are really driving a short-term view of transmission expansion, when

really what we can benefit from is a much longer-term view. Yes, we agree wholeheartedly. These are major investments.

We'll talk some about what it takes to develop a transmission project and the financial and time investment in permitting, regulatory approvals, and those kinds of things. All of that needs to get better to really get us to where we need to go. But thank you for your question.

PNM added.

I appreciate the question as well. We're going to get into more of the specifics for transmission within the IRP or where things might need to move towards, specifically related to perhaps a different connector called integrated system planning as opposed to integrated resource planning and how we might get to that point.

There are some very distinct nuances as well about the PNM system we will go over, specifically the vast amount of transmission that is planned for and utilized by non-retail customers, and the subset of the requirement that the PNM IRP only look at retail operations.

So, we agree that there needs to be a better job of transmission work. There are some significant limitations on why or how we can do things. And we hope to get to explain that before we get into the details of the IRP and transmission components.

InterWest Energy Alliance: Converters

I'm glad to hear you're looking at what it would take to replace or upgrade the converters. Are you looking at just replacing the same capacity? Or are you looking at increasing the capacity so you could transfer more across the ties?

Initial Response: PNM Transmission

That's a really good question. We're looking at just replacing right now. Because even if we are to make that larger, with the technology of the HVDC converters, the size is a really significant factor. And we think if we were to increase the capability between the two interconnects, we're looking at doing a

parallel device. Because of the way the technology is designed, it's not amenable to being a really large piece of equipment.

We also like to spread our risk. So, a lot of what we're looking at on the transmission nowadays is resilience. We know that extreme events or extreme people can cause harm to equipment and locations. And we're looking to try to spread risk as much as we can. Transmission development and additional HVDC cover capability will probably have to go hand in hand, given the transmission capabilities that are out there to support a bigger converter.

InterWest Energy Alliance continued.

So, I think what I heard, just want to make sure I got this right: You're not looking so much to expand what you have at the existing ties, maybe adding another one? Is that what you're thinking?

PNM Transmission continued.

That's something that, if we were going to go down that road, we would do. We don't have plans for one today. But we have had discussions with entities who are looking to expand the capability between interconnects.

This is a great segue into our next set of slides (starting at Slide 12), Were going to talk about an NREL (National Renewable energy Laboratory) study that talks about the benefits of these interties and the value in expanding and creating additional ties.

TECHNICAL SESSION #6: October 6, 2022

NM AREA: Scenario Analysis

One of the things E3 talked about was scenario analysis, sort of the middle course method. PNM has done some co-optimizations. Very slow. Very limited. And you've done the approach of adding, also on the cost for the transmission as an adder.

Could there be some potential, and maybe [this will] depend on RFP results, for [something like] PacifiCorp it did - they had a large collection of RFP results, so they had resource options. But they did

some scenario analysis, basically comparing one portfolio—if you built a certain transmission project that had been identified in the past as potentially being beneficial—and then take another scenario with an alternative portfolio that's optimized, assuming you don't have that, and then compared [them].

Do you see any opportunity for potentially doing that? Though it might depend on what you're seeing in your results, when you actually get in, to start doing the IRP.

PNM Response

We're certainly going to consider different scenario analyses and whether or not they make sense. We think we're still defining the scenarios we're going to be looking at.

One that might pop out is a wind scenario where the transmission delivers that wind versus something where that's not there. If you're speaking of the Energy Gateway project, which, of course, has been working for a long time. Or take other things like NV Energy, which did a scenario where they were looking at an additional north to south line. Those were some very concrete proposed transmission lines that were not only justified for bringing on new resources, but also reducing significant amounts of congestion across the system.

And if we're looking at transmission to just deliver resources, the ability to model a scenario or the need to model those as a scenario with anything other than a transmission hurdle may not make sense.

NM AREA: Transmission Congestion

Do you see this as really a tool for better understanding congestion going forward because, again, the zonal models have limitations and it's an art to putting those together, right?

So, there's some art to this but this would give you a much more accurate picture of the congestion situation. For example, you could run future portfolios for a sample year in the future, or you could look at are there congestion transmission projects that make sense for the PNM transmission system as a whole? That is, not just PNM retail but PNM retail and the other transmission customers? Is that how you're seeing this?

Initial Response: PNM Transmission

That's a good question. This slide (Slide 31) was sort of intended to help possibly answer that.

I think the first thing we're trying to do is to understand whether the portfolios PNM comes up with continue to make sense when we get better information on how they fit in with the transmission system. So, sanity checking the IRP portfolios is the first goal of this: when we put future expansion or resources PNM is proposing into these rungs, are we seeing anything unusual like transmission constraints that were not captured previously in the zonal model, and that would lead to curtailment or might lead to a different decision about where storage should be located?

So, informing the IRP process initially is the primary goal.

Going forward, we will certainly use it as a department to help quantify congestion in general, especially around interconnection and transmission service requests and how they might be impacted so we can provide better information to our customers.

In the deterministic approach we use today, you tend to be pretty conservative. You may have constraints you can't honor all hours of the year. And that tends to come across as something that is too prohibitive, where, in reality, some congestion might be tolerable, and the correct economic decision is to live with it.

So, we're trying to get a better understanding of those types of things. Also, from this type of modeling, the other thing we'll look at is whether it's providing insights to do a better job on capturing the zonal model. We can't get away from doing the zonal modeling in the IRP to capture the 20-year production cost of the different portfolios; you're still going to have to utilize a zonal model to do capacity expansion type runs and capture your total production cost over time. We'll use it [the zonal model] to help see if we can come up with better insight on what looks like the real constrains to PNM. We may be able to, over time, actually have some of the zonal model capture some of those other company uses, we would probably have to aggregate a lot of that information, but there will be things we study to see if we can do a better job on the zonal modeling based on new information we get out of the nodal runs. And then of course it will certainly provide some significant insight into what transmission expansion seems to make sense over a long-range period. We'd be looking to try to extract specific transmission plans, that when you look at over a long enough period of time, the economics of adding them make sense.

PNM continued.

What we see as the path for additional transmission modeling, or more co-optimized transmission and generation in the IRP is really going to be once we have the nodal model calibrated, we go through a process of determining how to use that information to better represent a zonal model. Or, perhaps to the point where computing power will allow us to run a reduced-form nodal model for capacity expansion, that would model better the transmission system in there.

Incorporating additional transmission candidates becomes an additional part of the problem, but it's not something we're considering, at least not initially – we need to get the nodal model set up right and make sure that we can utilize it in a way that we get some sensible results. In terms of running a full nodal analysis on IRP portfolios, that's something we discussed but that again will take a lot more time to determine the best way to do that. For example, the transmission build-out that may be required if we have an economic development boom and the size of the system doubles. Additional transmission network required to service that load and the resources to service that load could be completely different from what you would represent in just a standard ordinary load growth case. Trying to assess what the loads and resources might be on a full nodal basis under some of these high load scenarios would require so many assumptions that it really makes sense to run those for a couple of key portfolios associated with the MCEP.

All of this is to say that there's a lot more work to be done – we're trying to give some nights into the work that we're currently doing to try to improve our insights into the transmission system and how we're going to be modeling that going forward, but it's going to be some time until we can take those nodal databases and transfer them into information that can be used to represent in a different way within the integrated resource planning process. It's going to take some time.

Hecate Energy: Contract Path versus Physical Path

So, do we model contract path versus do we model just the physical flows relative to the inverse impedance of the system?

Initial Response: PNM Transmission

Yes, models don't really have a concept of contract path, so from that perspective, no. They do have the ability to model transactions, one area to another or from one part of a system to another, which may capture some of that. Typically, transactions are pretty uncommon in these databases, as provided.

We will probably try to simulate some things. But what we'll be looking for initially is the services that are being provided to the net transmission customers. Are there any constraints actually being run into on providing those services? And if that's the case, then we would have to dig into understanding who's got the rights to be on that system, if somebody has to be re dispatched and stuff, which gets back into who owns the TSR (Transmission Service Rights), who has the wheeling rights.

And that's particularly true going forward when you've allocated your system out close to limits in several different ways. As you go forward, you're looking at how you manage that.

Hecate Energy continued.

That's exactly what I asked because I'm familiar with the MISO market, premarket, post market. Post-market the TSR numbers went down drastically.

NM AREA: Cost Adders and Generic Resources

I'm struggling understanding the difference between these two (Slide 21). I'm assuming the initial modeled topology is essentially related to the slide previous to this.

Initial Response: PNM

That's correct. That's where we had the actual pipes and bubbles from each zone. And each pipe had its own cost. And behind that pipe, you had resources that could utilize that pipe. And so that pipe had cost and had capability.

NM AREA continued.

So, as I'm understanding, was it done as a price adder to the individual resources? Or the pipe was actually one of the selectable, essentially resources, even though it's transmission?

PNM continued.

Yes, it's a lot of the pipe that was an actual asset that could be added or could be optimized within the capacity expansion.

NM AREA continued.

And really, this is the first time you ever tried any of that. I recall the discussion from the IRP report.

PNM continued.

Yes, that's right.

NM AREA continued.

So, then my issue becomes better contrasting what the final model topology is actually doing versus this.

PNM continued.

The final modeled typology is essentially cost adders for generic resources. And, and when I say that what I mean is that we don't have those zones, those pipes and bubbles anymore. We just have generic resources that have cost adders for them, that can be added to serve our load, and it doesn't really matter in terms of the 2020 IRP what zone it was added in. It was more just to account for the transmission costs that we know of today that would likely need to be added because you have generic resources added over time.

And so, we're counting for the transmission costs there. But the generics would be added, as needed, to meet our demand and energy requirements.

NM AREA continued.

But is it a generic assumption regardless of where the generation is located?

PNM continued.

That's true. So, what we did was to still use utilize the same information that we had before, which was we had all the information about the different locations of transmission projects and their costs.

PNM continued.

For example, in the eastern area where the wind was located, the transmission hurdle rate was based on the eastern transmission line. And so, I think what you probably heard from E3's presentation earlier is when you're looking at just adding transmission to deliver to the load, the transmission hurdles are generally a reasonable methodology to do that.

When we're looking at adding the transmission topology and requiring the transmission pipes to be added along to deliver the resources, all you're seeing is a very similar resource that is added throughout the portfolio, you're just seeing differentiations, in which transmission was kind of added when, and it was all based on the transmission prices, because there wasn't enough differentiation on the resource prices.

In order to adequately do the combined transmission and resource modeling, you're going to need to have not just differentiations on the transmission capital cost, but you need to have differentiations on the production profiles, capital costs, land costs, all those other things for the resource side.

And so that is something that is much more difficult to put together outside of an RFP process, because we don't necessarily know what incentives a particular community or county is going to give to a developer for IRBs, or avoidance of property taxes, things like that. We don't necessarily know what their land costs are going to be.

And so, if you don't have a differentiation on the price side for the resources, it just becomes which transmission is cheaper, and it doesn't give you the full picture.

So that's one of the difficulties that we found here.

NM AREA continued.

Yes, I guess it is an order of magnitude question, though, on those differences in those costs, influencing a location.

PNM continued.

Well, it's influencing the location, but it also influences the run times on the model.

NM AREA continued.

The more complicated the problem is, right, the more

PNM continued.

You don't have the differentiation in prices, and you have all these similar resources that are priced similarly. And the only differentiation is that the transmission piece, the model, and trying to close its tolerance gap can hang up much longer, and it can lead to significantly longer run times.

And the value that you're getting out of it is not good enough to say this is really what you would use to make a transmission investment decision.

NM AREA continued.

Right, this details where the model is selecting the projects, and selecting essentially the transmission and projects combined.

The second approach, though, is it a cost data approach. Is it a lumpy thing? Or basically is each resource—let's go back to the eastern—are there multiple resources in the eastern that could be selected? Or is it one resource?

What I've kind of been trying to understand is, do we create this big hurdle because of lumpiness when doing the cost adder thing? Or are you doing something more granular?

PNM continued.

For the eastern resource, we had assumed, the original transmission line that was developed as a proxy by the transmission group was an 800-megawatt line, essentially, a Western Spirit II or a BB3 type line, that would have 800 megawatts of additional transmission capability. And there was a lumpy cost associated with that.

We model it as a 400-megawatt wind resource with half the cost of the transmission line, basically saying, there's going to have to be some project to get this thing off the ground, maybe there could be, half of it goes towards FERC jurisdiction and half of it stays within retail. There might be some ability to have a partner in that situation.

So, we didn't take it down where you can do megawatt by megawatt, but we didn't require the full 800 megawatts to be dedicated to retail.

NM AREA continued.

All right, that helps that so it's more about a more granular thing, but not super granular, but not as chunky as you got to get this through this theory bit—the cost of this very big transmission project even for something smaller. But realizing you didn't break until lots of little steps by just a few smaller steps.

PNM continued.

I just wanted to add that we compared the results of these two types of modeling efforts and what we really found is you're adding the same resources, the same types of resources, and around the same amount of resources in similar years for both topologies.

And the interesting thing about the zonal modeling is, where we actually put in the transmission pipes or projects as hurdles, that you have to build those first, before you add resources behind them was that

it was always adding the lowest cost one first. So, if you have $100 million project or a $500 million project, we're always seeing the 100-million-dollar project, or at least the resources from those zones added first, along with that transmission project.

When you're talking about, say, the different solar areas, wind was a little bit different. But then again, the difficulty is that when we go and we look at some RFP type data, there is differentiation of the prices, depending on where the projects are located. And having just generic resources in there without price differentiation, which, again, PNM does not have specific sites that we have interconnections at all across the PNM footprint. There're very specific sites that we have.

And so, without the price differentiation, it just becomes what's the cheapest transmission.

But when you're doing the generation and transmission investments, through an RFP, it's going to be the combination of what's the cheapest generation, including the transmission. And that's just a difference between an RFP evaluation, and something that looks at trends over 20-year time.

InterWest Energy Alliance: Projects Within Zones

[Regarding Slide 20], I think what I heard what you say is that what you did is identify transmission projects from each of these five zones, but only in relation to a known generation resource within each of these five zones that needed transmission in order to get the energy to load. But if you didn't have a known resource in one of those zones, there was no impetus to build any transmission. Is that about right?

Initial Response: PNM

What we did was have PNM Transmission Group give us the potential transmission upgrade projects that they are aware of from these types of zones. And this is what the Transmission Group went over the last time we talked about transmission. For instance, the Transmission Group had three different transmission projects coming from the north, and each had their own cost and megawatts, incremental megawatts that you can deliver from that area or from that transmission line.

We utilize that information from each of the zones to determine what these pipes would represent. And then, for the bubbles for each zone, the way we set it up was to say, "Okay, you have the same technologies within each of the zones that you do across the board." And that with the exception of the

transmission zone east, where you had wind, and within the zones, the way we set it up was, to say, "Okay, well, you're limited to adding resources from each of those delivery zones."

There isn't just this unlimited zone where you can just add as much as you want. So, you have to choose a zone to put your resources in, and you're going to have to pick basically a pipe that you're going to need to build.

It's going to ask you to optimize. I was asking EnCompass to optimize around that type of problem.

InterWest Energy Alliance continued.

It sounds like you didn't take a fresh look at what the potential is in each of these zones. You just looked at what the known projects, or whatever, are from each of these zones.

PNM continued.

That's correct. We did that to the east, for example. We know of a project from that zone. And that's the project that the Transmission Group presented on. It's an 800-megawatt project, with a cost on the order of $300 to $400 million. So, that's the project that we modeled.

We didn't go through and try to go beyond that and say beyond the 800 megawatts of that individual project that we're modeling, you can add beyond that, because we don't have a specific project or certain costs that we would tag on to that from this zonal modeling perspective.

InterWest Energy Alliance continued.

So, for example, with respect to the south zone, you didn't look at the benefits and costs of adding more capacity to link up with, say, EPE (El Paso Electric) and resources that could be developed in the south to maybe enhance reliability. That wasn't part of this modeling effort?

PNM continued.

That's correct. That was not part of that modeling effort. The focus of this was to try and determine if there was an optimal set of transmission projects that, if needed to be built, if everything is, fully subscribed, and we have to build transmission, and we need resources to meet our load, what transmission projects will we need to build and when over the 20-year planning horizon?

InterWest Energy Alliance continued.

Okay, it sounds like this kind of modeling may not be the fit for what I just asked about. Is there some other modeling approach that would be better for looking at overall system improvements for reliability and linkages to other existing systems?

PNM continued.

And that's a good question. It kind of sounds like what you're asking is what is best for the transmission system? And this may be more of a transmission planning type of question. From our perspective, we're trying to do our best with the best information we have in terms of what transmission projects are out there.

And like we mentioned before, we are not accounting for the system reliability in any way in this type of zonal modeling framework. That's where transmission planning would have to come in. And this would be the idea of a coordinated effort between IRP and transmission planning on how to define what these zones may be, what the pipes may be, in that type of context. That's where that would have to take place.

But in terms of the 2020 IRP, this is how we did it last time.

Sandia National Laboratories: Investments into Projects

Maybe [this is] related to the third option, the more complex and customized generation and transmission**.** With the zonal model, you get those transmission investments kind of from a zonal basis. So, I was just curious, in your screening of current IRPs, or even what you have (on Slide 15) on integrated system planning, what are some methods utilities are taking to kind of translate those aggregated transmission investments into actual transmission projects?

Initial Response: E3

In terms of taking a broad zonal sort of perspective on transmission, and actually translating that into specific projects, that kind of gets to this question of how does the IRP intersect or integrate with the transmission planning efforts, if at all.

One example that exists out there that you might take a look at is what's going on in California as it relates to their IRP process and the Cal ISO's transmission planning process. Within California, the CPUC (California Public Utility Commission) administers a sort of top-down integrated resource planning process that's actually developing sort of a statewide resource portfolio that achieves the state's greenhouse gas goals.

There's then separately a process where that portfolio of resources--in the large quantities of solar and storage, and wind--are kind of mapped or downscaled to a much more granular level through a process that they call busbar mapping, which is essentially a process of taking all the solar and wind and storage resources and putting them on very specific parts of the system.

And then that portfolio and all that locational detail is handed over to the California ISO, who then goes through the paces of saying, well, with this highly granular portfolio of wind, solar and storage resources, what are the transmission implications of that portfolio?

So that's one example of a process where you've actually got two sides kind of working, trying to work together to sort of translate some of those less granular outcomes from an IRP process into potentially more specific transmission needs under a high renewable scenario.

Sandia National Laboratories continued.

That helps. I think MISO might do something very similar. I was just curious if you were seeing more utility level within these IRPs, or maybe we'll call them ISPs now. So, yes, definitely, ongoing work for sure.

Hecate Energy: Generators and Interconnection Processes

When a generator joins a data collection process, there'll be some reliability updates assigned to it, right, based on the interconnection study. So, are we talking about upgrades? Can you explain that?

E3 Response

First, as I tried to lay out upfront, the IRP process is a little bit different from the transmission planning process. And so, a generator that's going through the interconnection processes, kind of within the utility's transmission planning process, the Transmission Group will be assessing the need for the interconnection related projects and stuff like that.

In an IRP context, utilities aren't usually focused on individual projects, interconnection requirements. And to the extent that they're thinking about transmission in the IRP processes, it's actually usually larger scale conceptual projects that allow for the delivery of larger quantities of resources across a broader area. So, within the IRP, that's actually more so the focus when utilities are thinking about the transmission: It's what does it take to get a large quantity of resources from one part of my system to another?

InterWest Energy Alliance: Value of Reliability Benefits

Do any of these methodologies take into account benefits, such as reliability benefits, and assign a value to them that can then be assigned a dollar value instead of just the amorphous…it increases reliability but we're not assigning any value to it' that I've heard in several IRPs.

E3 Response

Within an IRP context, I don't think I've seen any examples where that sort of reliability benefit is quantified in sort of a dollar term.

What I will say is that the specific investments, or projects, that are often considered, are often characterized in such a way that they're meant to provide the reliability service that comes along with the resource that they're connecting. So, in that sense, there's kind of an implicit benefit that comes along with being able to take that resource and put it into the portfolio.

But I haven't seen it quantified as an explicit benefit in an IRP.

Hecate Energy: Cost of Generation

I think you need the cost of generation also, like different generation types will have different costs, right? Are you using any numbers for generation when you look at these scenarios and evaluations? [Slide 14]

Initial Response: E3

This is largely a survey of what others are doing on this. But I will say yes, you're absolutely right. The generation cost is a very important piece of this.

And because this conversation is about transmission, we glossed over or skipped over a lot of the dynamics that might be in play in terms of how resources are being represented, both in terms of cost and their capabilities. And absolutely, that's an important part of the equation here.

Hecate Energy continued.

I kind of thought that, too. Basically, I guess what I was getting at is I'm used to the PROMOD type evaluation of transmission where I use the LMP (Locational Market Pricing) and things like that. But hopefully, I'll learn things as I go.

E3 continued.

I appreciate the comment. And maybe it makes sense to just point out [your mention] of PROMOD, which is kind of in the production cost family of resources. Within the context of an IRP, many utilities are starting one step removed from that, which is with a capacity expansion model.

This is the approach that PNM uses as well, where you're explicitly looking at not just how does the system operate, but what are the costs to build all the resources to make that system possible and optimizing around not just the operations of the system, but the investments as well.

Hecate Energy continued.

I didn’t explain it well. Well basically, what I'm looking at is, like MISO or ERCOT; they have the transmission economic evaluation. So, basically, the cost of the transmission upgrade, and then what are the benefits? So, it includes the societal benefits also.

And then I think it's like 14% of benefits the first year. That is the passing criteria for transmission, economic transmission. So that's the type of that value. The benefits are calculated, based on PROMOD, and probably there may be other inputs to calculate. It's like over a period of time or, I think, in the case of ERCOT, the first year. MISO runs several years, up to 20 years or something like that. Several PROMOD cases to find the benefits of transmission upgrade to loads. The MISO process has benefits to load and generation and so the reduction in costs to generation and things like that.

NM AREA: Benefit of Scenario Analysis Approach

Would you say it's fair to say that the scenario analysis approach works particularly well when a utility has identified various candidate transmission projects or expansions that have clear strategic benefit? And if scenario analysis kind of works well for identifying when those projects really become either cost effective or have significant benefits to justify moving forward? [Does] it work well, in that respect?

Initial Response: E3

That's a pretty fair characterization, you might say, when or if those projects have significant benefits, because it could be that you conceptually identify a project that you think might have benefits, but then you put it through the paces of the modeling, and you might find, well, actually, there's another strategy that seems to be superior to it under the sort of uncertainties that we're operating in.

But I generally agree with the spirit of your comment.

NM AREA continued.

I guess I get that from [when] PacifiCorp identified the strategic projects like a decade ago, mostly. And the question [is] always: When is it justified? And so, their use of scenario analysis has helped them to justify projects and when not to pursue them.

E3 continued.

You raise a good point there, too, which is, once again, it's taken PacifiCorp and Idaho Power kind of a long time, from the point at which those projects were originally conceptualized and identified as potential strategic projects, to the point that they're at today.

So, it maybe there's something to learn from that: that there is sort of a long history that's led them to the point they've gotten to.

NM AREA continued.

I guess where I'm thinking is that where you can't do everything, but it may be important for a utility to identify what those types of strategic projects or opportunities are so that then they can be further analyzed in a scenario analysis type approach.

NM AREA: Transmission Integration Projects

It's more of a comment. You've partly acknowledged [that] there are some exceptions, but not just in CAL ISO/MISO. PacifiCorp, for example, [with the] Gateway South project that was fully integrated in their most recent IRP. And the decision was integrated on both the resources and moving forward with that transmission project**.**

And it could be argued, to some extent, some of NV Energy's recent transmission developments are tied together. I mean, not so much in an IRP, but the consideration of resources was a major driver moving forward [with] those transmission projects. So, I agree, it's somewhat in its infancy, but it is happening. And there are examples.

E3 Response

We appreciate the comment, and you're actually kind of one step ahead of us, because PacifiCorp was actually one of the case studies that we were going to call out later in this presentation as maybe a leading example of a utility that is kind of farther ahead on this spectrum. When we get there, if you

have any comments you want to add in at that point, we'll be happy to have a further discussion about it.

Gridworks Facilitated Stakeholder Process (March 28, 2023 - October 19, 2023)

March 28, 2023
Meeting #1: Orientation for PNM Integrated Resource Plan

Stakeholder: In-Person Workshops

Will the signup for the in-person workshops be on the PNM website?

Gridworks Response

We're working to try to make sure that we have information both on the Gridworks website and on the PNM website, so you could go to either place.

We understand that this transition is going to be a little challenging communication wise, but we, again, are very pleased with the partnership that we have with PNM and the communications back and forth to make sure all of you learn what's next and how to reach us--a high priority for both Gridworks and for PNM, so we'll continue to try to get information in multiple locations. But we'll try to streamline the registration process**.**

Member of the Public: Role of PNM Holding Company

How does the holding company for PNM affect what PNM is going to do?

Gridworks Response

That's not directly related to [today's presentation] but it is important.

Additional (Previous) PNM Responses to Member of the Public

Member of the Public

What is the relationship between PNM and PNMR and what is the role of each in the IRP process and implementation?

PNM Response

PNM is a wholly owned subsidiary of PNM Resources. PNM is a regulated utility subject to the rules and procedures of the New Mexico Public Regulation Commission (NMPRC). The IRP rule applies only to PNM, not PNM Resources. PNM Resources is a publicly traded company not directly subject to the regulatory oversight of the NMPRC. PNM is responsible for developing the IRP and must make filings and gain approval from the NMPRC to acquire any resources subject to the NMPRC's Certificate of Convenience and Necessity ("CCN"), Power Purchase Agreement ("PPA"), and other applicable rules.

Member of the Public

What PNMR businesses are within or outside the IRP process? What percentage of PNMR are in each of these categories?

PNM Response

The only PNMR business subject to the NMPRC IRP rule is PNM.

Member of the Public

Does anything in the non-regulated sector impact on PNM's planning and/or operations? If so, how?

PNM Response

Many things in unregulated sectors impact PNM's planning and operations, such as the price for new resources, the cost of natural gas, the cost of capital, regional markets and other factors – all of which are not regulated by the NMPRC. Most of the fundamental drivers in the planning and operations process are things beyond PNM's and the NMPRC's direct control. PNM plans within uncertain environments to best meet its customer's needs. PNM's rates, procurements and operations are regulated by the NMPRC.

Member of the Public

How do unregulated activities relate to the IRP process?

PNM Response

See response to the previous question.

Member of the Public

What are the PRC's objectives and expectations for the IRP process?

PNM Response

The NMPRC IRP rule provides the objectives of the IRP process.

Member of the Public

In the revised IRP rule 17.7.3.1 NMAC of 10/27/2022, which parts are new, and which carry over from before? A table showing the changes could be helpful.

PNM Response

Please find attached Exhibit B which is a redline of the previous rule to the new rule which was filed in the IRP Rulemaking Docket, Case No. 21-00128-UT.

Member of the Public

Where are the stakeholders defined in the new Rule?

PNM Response

Stakeholder is not a defined term in 17.7.3 NMAC.

Member of the Public

How do the commission or PNM know when enough varied stakeholders are participating to meet requirements?

PNM Response

The facilitated stakeholder process that is currently being conducted by Gridworks has been sent to a very broad group. Facilitated stakeholder process is defined in 17.7.3.7(F)(1) NMAC.

Member of the Public

What happens if no stakeholders can be enlisted from a given key sector?

PNM Response

The Commission determined in its rulemaking that the Commission-defined facilitated stakeholder process is appropriate to receive public input to the IRP.

Member of the Public

How does the Statement of Need relate to PNM's business plan and operations?

PNM Response

The Statement of Need defines requirements that PNM must meet in the future; however, before finalizing agreements with any new resources, PNM must seek approval from the NMPRC through filings for a CCN, approval of a PPA or other applicable approvals. Therefore, the Statement of Need outlines a high-level roadmap for future procurements and investments by PNM, but actual outcomes may vary when specific market bids are sought to inform procurement analyses and filings.

Member of the Public

Is the Independent Monitor for RFPs a new element under 17.7.3?

PNM Response

Yes.

Member of the Public

Under 17.7.3.12**(**F)(4) NMAC, What is meant by “resources be able to operate under automatic dispatch control”?

PNM Response

Resources that have Automatic Generation Control (AGC) can follow a dispatch signal sent by the remote system operator to vary its output to a desired set point.

Stakeholder: Availability of Models

There's not enough time and models should be made available ASAP.

Gridworks Response

One of the things that that we're going to be working through is whether the modeling software is available to you as stakeholders, or whether we're going to work with PNM and be able to talk about PNM’s assumptions and how their modeling is done.

Stakeholder: Recordings of Gridworks Meetings

Will the recording of this call be distributed to participants?

Gridworks Response

Yes, it is recorded, and everyone will have access to it. It will be posted, so it will be available to anybody.

Stakeholder: Availability of Input Data

Hopefully, the input data will be available.

Gridworks Response

Obviously, the assumptions that go into modeling are critically important and some of those may be confidential; some may not. And so, we're going to have to work through what all can be provided to stakeholders because the basis for what comes out of the model is the assumptions that you put into the model.

Pine Gate Renewables: Availability of Modeling Software

I just wanted to quickly make a comment that, at least for us, we've really like the approach that we've seen from APS in Arizona … Specifically, how they have opened the space for some people to use the modeling software that they are using, if those people have capacity, while also acknowledging that some people, a lot of people on the development side, do not either have the time or expertise to participate in these modeling exercises.

But APS has offered to create Resource Planning Advisory Council ("RPAC") model run that brings in a lot of the ideas of what the stakeholder group wants into one of the model runs. We'd be interested in seeing if that is a possibility here as well.

Gridworks Response

Thank you. That's super helpful.

Synapse Energy Economics: Availability of Modeling Assumptions

If modeling assumptions can be made available before the meeting, then discuss them [at the meeting]; that gives time to be reviewed. That would be ideal.

Gridworks Response

Good suggestion. Thank you.

NM AREA: Meeting Schedule

[I would like to suggest that these meetings not be scheduled on top of a rate case hearing.]

NM AREA: Availability of Models

I think the IRP Rule requires that PNM make the model available to any stakeholders that are interested. I would echo one of the comments that was just made.

In the past PNM has made the models available in multiple different ways. For the stakeholders that have the expertise, they've given them access to the models with the inputs. And then, for the stakeholders that do not have the expertise, they've allowed certain amounts of modeling runs that PNM would do on their behalf. In another scenario for those that don't have the computer space to totally run all the models, PNM has Virtual Machines ("VM").

So, I'm not quite sure how PNM is going to handle it in this IRP, but it did take a long time to figure out in the last IRP. And so, I would suggest that be one of the first areas in this [process be to get] things ready before the official start date to really figure out how you all are going to offer models and different stakeholder options for those models so that we're not arguing about that during the start time. [That way] we already have a process set up, and that we can work out all the bugs now because we have a little extra time [to see] how those models are being used, the data that's in them, and the data that's supplied (what's confidential and what's not).

If all that could get worked out beforehand—that in itself takes one to two months. And so that would be extremely helpful because we lost a lot of time on the frontend last time and we don't have the

resources PNM has and, obviously, they're PNM's models, so they're **more familiar** with how to modify them.

So, I think that would be one of the first things to figure out and present to the group. That way, because there are only a couple months to do modeling runs, the time could be used really efficiently. If we're working out the kinks during that time, there's going to be very limited time to even conduct any runs. PNM has said some of these runs can take weeks to solve.

So, that would be my recommendation for the upcoming March to May timeframe.

Initial Response: Gridworks

Thanks.

PNM continued.

For all those folks who are inquiring about input assumptions and other such things along those lines, we would encourage you to please visit the PNM IRP website. There have been 15 meetings previous to this where we've discussed a whole host of different modeling assumptions, techniques, frameworks, et cetera, so a lot of that information is out there.

If you have not been following the process so far--I know we're transitioning to the facilitated part of this process--but there has been a lot of work done and reviewing all those materials will get you a head start in terms of trying to get more in line with what we've been doing thus far in terms of modeling, inputs, assumptions, frameworks, techniques, et cetera.

I appreciate NM AREA's point. We'll have to talk about all that because, as we've discussed, there comes a point where we have to all be working with a consistent set of data. To the extent there's request for updates to the data--who knows what can be accommodated-- sending out multiple different versions of databases becomes very problematic.

Stakeholder: Status of Modeling

Does PNM's comment imply modeling already is already completed?

Initial Response: PNM

Portfolio modeling is still ongoing and will be part of this process of getting input in terms of different scenarios or sensitivities that maybe we have not considered that you would like us to do, Now, there has been a lot of modeling already done in terms of setting up the various inputs. We've already done modeling to do the load forecast. We've got 14 different load forecasts. We've already done modeling to assess ELCC curves and reserve requirements and energy efficiency bundles and all of these other things.

So, the modeling started to develop all of the inputs over a year ago. We're at a point now where we need to start figuring out if there anything else we need to be looking at as far as inputs, because time is of the essence in order to try to modify those things, or are we just going to be locking down the input assumptions at this point?

We're really trying to figure out are there different modeling requests that we need to accommodate, based off the existing information that we've already put together.

Gridworks continued.

Thank you.

One thing to point out to the group is that, because of the timing of the legislation, we've had to start this process after PNM has already initiated their process, as was mentioned.

So, we're trying to navigate how to serve the [Public Regulation] Commission best with its request and its new legislation while we're in the midst of this process,

Western Resource Advocates: Schedule

An additional in-person meeting in late May or June to specifically discuss modeling may be useful.

New Mexico State University: Resource Adequacy Runs

Will the process over the next few months include resource adequacy runs to confirm portfolio proposals?

Gridworks Response

Thank you for the input on that. Let us look at that and get back to you.

Office of Senator Heinrich: PNM Website Link

Can that link be provided to the PNM website?

PNM Response

Sure, we can put that link into the chat or send it out via email. It's generally the website we've got all the presentation materials from the previous 15 meetings that we've done. We're putting it in right now.

Gridworks continued.

We will also put it in the meeting summary that we'll send out—both the like to the recording for this meeting and resources where there's information--the PNM presentations from past

as well, as the this presentation, et cetera. So, we will make sure that those are referred to and linked in our meeting summary.

PNM Presentation May 11, 2023

Office of Senator Heinrich: Weighting or Combining Models/Scenarios

My question has to do with the scenarios. I think, as you get a lot of requests from modeling, having different models and different scenarios, how are you going to either weight them or combine them to give you your resulting distribution of LOLE upon which you can then act?

Initial Response: PNM

A very good question.

So, first we'll go through all of the different scenarios that we'll define through the modeling subgroups. We've got a list that I'll share here towards the second half of the presentation on individual resource scenarios as well as what we'll call complex or combinatorial resource scenarios.

We'll define a weighting system through some of the metrics we get out of the deterministic modeling first, in order to say, “Well, which ones pass muster, which ones don't?” And the way we're thinking about that is, for example, we'll have a baseline cost metric, an incremental cost metric to serve incremental load, and then, if we take a P50 portfolio and run it through an extreme weather case, that'll give us, albeit deterministic, a metric on incremental expected unserved energy for that given portfolio.

We can then take the overall realm of portfolios that we're looking at and, based on the results of the analyses described above, whittle that down to a shorter list that we will then run through the LOLE models and resiliency models to come up with some of those loss of load metrics on the stochastic basis and resiliency basis that you're asking about.

Does that answer the question, or do you want to go deeper?

Office of Sen. Heinrich continued.

No, I think that's good for now, but maybe a process diagram, maybe a sketch, would help as to what you described, summarizing what you describe, would be helpful. Thanks.

PNM continued.

Sure, appreciate the feedback.

Form Energy: Siting of Resources

I was just noting that in addition to the ITC, there are other tax credits that could apply to some of these technologies, particularly storage, including the ones related to percentage of domestic content and projects cited in Energy Communities.

I was wondering how those are going to be taken into account, if they are?

PNM Response

We are aware of those.

The IRP is not where we determine specific siting of resources; that's done through the RFP process when we look at where these resources would actually be interconnected,

I think that generally what we will end up seeing is that we'll stick to the baseline 30 percent ITC assumptions for storage.

We certainly could consider doing a sensitivity or two that reflected storage qualification for domestic content or other such things, but the actual siting and actual portfolio composition of generic resources that we would be modeling, I would say, we can't do everything.

So, we'll likely stick to the 30 percent and then allow the RFP process in the future to determine, for specific projects, whether they qualify for additional bonus ITC parameters.

Sandia National Laboratories: Timeline for Stakeholder Modeling Requests

[I have a] a process question. I know that last week we talked about having some set of requests ready for May 18, but then the official request ready for June 15. And so I just wanted to make sure everyone was on the same page in terms of what was expected for next week versus June 15. I think we know what's needed for June 15, but I was just curious about the interim ask.

Initial Response: Gridworks

Great question.

We have rethought that process and we've put together a modeling engagement plan that has clear dates and steps moving forward that we would like to get to everyone for you to consider for feedback before our next meeting on May 18.

That includes a May 25 date for both possible run requests and possible prioritization criteria, but more importantly, the big plan includes putting together a core team, a modeling core team, that will help process, prioritize, and consider this information with our help to then be interfaced with the PNM IRP modeling team.

So, you'll hear more about that, but for now the dates that we talked about on May 4 will still involve a little bit of movement. We're still working toward the June 15 date, but there will be some interim steps that get taken on by a modeling core team.

Does that answer your question?

Ballantine continued.

Yes, perfect.

Sandia National Laboratories: Cost versus LOLE

[I have not been able to find] but I'm really curious to see a graphic [showing] LOLE versus cost, probability versus cost, because I know that, I would assume that the lower the probability, the higher the cost.

I know that everybody wants really reliable clean energy, but there's a cost associated with all of that. So that's just my little curiosity. It's nothing earth shattering or that important, but before I spend an hour trying to find it, if somebody could just point me towards it, if it exists, that would be great.

PNM Response

I don't know that we have a specific plot that would show cost versus LOLE.

You would be right that the tighter the reliability constraints, the more cost we would incur.

We could point you to a supply side resiliency study that's on our website (link: https://www.pnmforwardtogether.com/assets/uploads/PNM_Planning_Resilience_v2.pdf) that showed if we wanted to start normalizing certain expected unserved energy metrics across a fully dispatchable portfolio versus renewable and storage portfolio, the amount of investment necessary to make those normal, not just on an LOLE or frequency-based metric basis, but on an expected unserved energy basis, would take storage that was 2- and 4-hours in duration and make it 14 hours and 16 hours duration.

And you can kind of think to yourself. “Well, how much more costly is that?”

Pine Gate Renewables: Thermal Units

I have a question about the way you were setting up the ELCC [to be] very specific to a few resources. I was thinking about if you [could] use Texas as an example: how the thermal units in that state have recently had a lot of trouble delivering despite being seen as resources that don't have an ELCC because they supposedly should be on or available at needed times.

So, I'm just kind of curious about how the modeling here; while the risk is maybe lower than intermittent resources, [I'd like to know how PNM modeling] factors in weather risk, forced outage risk, or planned maintenance risk into thermal units.

Initial Response: PNM

Thanks for the question.

We have thought about that.

The first thing that we're doing in terms of ELCC at least is we're using what's known as a UCAP or unforced capacity metric when putting the capacity contribution for thermal resources into the planning model. So, we're not just saying that they get a 100 percent nameplate, but it's something less based on either historic expected forced outage rate data or forecasted data for new units.

We've gone through and looked at data from NERC (North American Electric Reliability Corporation) GADS (Generating Availability Data Standard) data. We've gone back and reviewed that and done some analysis regarding the question: "Can we determine for PMM's units any type of weather dependency outages for extreme temperatures?" And the answer so far is no.

Back in 2011, there was a pretty bad cold snap that did cause some things to happen on PNM’s system, and PNM at that point put together a plan to weatherize a lot of the plants. And so, in recent years, when we look at what's going on with our plant availability, we don't see any data-driven analysis that shows correlation between weather and outages on our fleet.

We also did a supply-side resiliency study that asked the question, “Well, what happens if you did have correlated outages, say, with fuel supply disruptions or other impacts to different elements of the system?” And so, we would plan on--we talked about this on May 4 [2023]--building into our overall framework some resiliency analysis.

Some things we're looking to get out of that resiliency study are: a) given the results, what would the stakeholders recommend, as well as b) what would our customers be willing to bear in terms of the increased costs associated with the necessary investments in resiliency refinements to the system versus the probability of outages and how much the cost of those outages would be.

So, we do have that type of framework in mind, but as far as coming up with ELCCs for the existing system--for gas units, mainly, I think what you're getting at--we don't see anything in the data that would suggest the necessity of that analysis.

Finally, if we look at where the risks are on our system, predominately before we get very far out in the future, it's mainly summer net load risk. The majority of the types of correlated, weather-dependent outages or common mode failures [I think you're referring to] are associated with winter risk that we're just not seeing on our system.

I know there was a study done for Texas as well as for PJM, but the risks to our system are just not manifesting in the same way.

Pine Gate Renewables continued.

Appreciate that.

Form Energy: Time Periods for PRM and ELCCs

You mentioned that, in the initial resource adequacy modeling for determining the PRM and ELCCs, as well as during the capacity expansion modeling, the team chooses to model kind of a relevant subset of hours rather than all 8760 hours of the year.

So, I was just wondering if you could elaborate a little bit on how those time periods are chosen and also how resources such as long variation energy storage might be treated under those frameworks, given that kind of their operational profiles over the entire year shifting energy from one season to another are very important to their reliability contributions.

Initial Response: PNM

Thank you for the question. Another great question.

When we're doing the ELCCs, and the reserve margin calibrations [SERVM modeling], that is actually five-minute modeling for an entire year across multiple weather years and multiple forced outages, load forecast uncertainties, et cetera. So, that is full year modeling deep down to the five-minute level for establishing those pieces.

For the capacity expansion [EnCompass modeling], after we put the ELCCs and reserve margin into the capacity expansion model, for some of the runs that will be looked at, the capacity expansion model will be limited to, say, a typical on-peak and off-peak day per month for each month of the 20-year planning horizon.

We understand that, for example, with long duration storage, that may not allow the model to fully capture the benefits of long duration storage. So, for those long duration storage aspects, what we'll have to do is force into the model the long duration storage, drop down into a middle step that's not fully described here but is described in the presentation we made on July 27 [2022] as part of the PNM Public Advisory Process (link: https://www.pnmforwardtogether.com/assets/uploads/Slides-IRP-Technical-Session-4-IRP-Modeling-Updates-Techniques-Final.pdf).

A quick summary of the intermediary step: Rather than doing, say, rolling weeks for production cost simulations, we'll force 18 months of data into memory at once on an hourly basis. So, that way the model has kind of perfect foresight in order to capture the seasonal build up, flow up, flow down of energy in and out of the long duration storage asset. So, we can get kind of an optimal use case for that.

We can then build that operation back into the larger capacity expansion optimization to make sure that use case is then reflected when making decisions around additional resources in the rest of the portfolio for [the entire 20-year timeframe].

And then, once the optimal portfolio is determined, we'll drop down into more detailed production costing, where we force even more granularity, and even more constraints on, say, minimum uptime, minimum downtime, and other binary variables.

So, we recognize that for long duration storage, whether it's iron air core, whether it's pumped hydro, hydrogen, other such things that require that seasonal buildup, there has to be an intermediary step where we're putting at least a year, more likely 18 months, of data into memory at once in order to make sure they were able to have the model see and understand the needs for that seasonal build up and draw down over time.

Form Energy continued.

Got it. That was really helpful. Thanks for walking through that and just a quick follow up.

Is there room for us to kind of engage on these types of questions and approaches as part of this IRP stakeholder process versus kind of just suggesting the scenarios and futures for capacity expansion modeling?

PNM continued.

We're absolutely open to feedback through the modeling working group and subgroups.

I think that whether or not we could adapt a framework to incorporate changes would depend on how we can do testing of that change to the framework, get comfortable with it, and believe that we can incorporate those changes and still meet our filing dates.

Form Energy continued.

Got it, yes.

Gridworks continued.

So let me jump in.

Yes, people have had suggestions on adjusting a framework that might be better suited to where we're headed in the long term. Those are entirely welcome and this modeling engagement plan that we're going to distribute to folks will talk about that. We are going to collect those ideas.

The utility is not obligated to make changes to their framework at this point because there's quite a bit of validation and verification that would have to be done to any new framework, but we are collecting those because that's part of input to the [Public Regulation] Commission about moving ahead in the future.

So, thanks for that idea. We will be collecting those ideas and there will be opportunities to discuss those.

Form Energy continued.

Okay.

Mitsubishi Power: Candidate Resources

I have a two-part question.

First: When I look at your candidate resource document on the gas turbines--that you only have considered aeroderivative gas turbines. Why are you not letting the model choose from many different other options? As you've noted $1,469 per kilowatt capacity--simple cycles, heavy duty, simple cycles are at least $500 less. So, why are you not letting the model choose from that?

PNM Response

With regard to the candidate resources, we're open to modeling others.

For what we've looked at on our system, we believe that aeroderivatives with the vast ramping capability will provide the most value to our system, especially being able to move towards our

renewable goals and help chase renewables and a lot of those renewable integrations where the combustion turbines don't necessarily have the same start time, minimum load characteristics, and ramping capabilities as aeroderivatives.

We're not saying that we would limit ourselves to that. And we could look at some others. I often think that when the rubber meets the road, the IRP does not determine what resources we are adding; it gives us general trends.

And to the extent that there are resources with relatively similar characteristics, when we go to an RFP, we're not going to say we're doing an RFP for aeroderivatives; we would be saying we're doing an RFP for resources. And to the extent there are other resources that help meet those needs with similar operating characteristics, we would then make those decisions on a cost basis.

Mitsubishi Power: Chronology for Capacity Expansion and Production Cost Modeling

Second question: Does EnCompass have the ability to run capacity expansion with fitted chronology, which is to say you're running the entire 8670 in a single [MIP problem]. That way you do not need to use the ELCC methodology; you can actually directly go and give the model the rating factors of the solar resource and wind resource, and let the model decide how much storage and primary resources it needs to build.

Initial response: PNM

So, EnCompass does have the ability to make the problem size as big or as small as you want, but putting 20 years of 8760 data in the memory just won't solve, at least not on our machines.

Mitsubishi Power continued.

You can do one year and then roll over and then carry forward one year.

PNM continued.

If you were to do one year at a time, you wouldn't have the ability to understand how 2040 is affected by a capacity decisions in 2025.

So we need to have a planning problem that has a multi-year horizon when making those capacity expansion decisions. And I would say, regardless of whether you could put the full 20 years in at 8760 data, if it's still done in a deterministic fashion, you can't get away from having ELCCs.

The end-all solution in PNM's mind would be having a capacity expansion that had a stochastic sub-problem that incorporated loss of load probability metrics within the production costing aspect that would be feeding back into the capacity expansion problem. But that's just well out of the realms of current computing power and models.

But if we can't put a stochastic production cost in, even just doing a single deterministic run on capacity expansion, even if you could fit the 8760 for 20 years in, it would not give you enough detail in order to assess what the reliability contributions of resources were.

New Mexico State University: Timeline for Modeling

I think we should be really clear on the timeline because modeling is an iterative process.

Will we get to see the results from PNM modeling on June 15, 2023, so that we can see, maybe, what gaps or what new information that provides to inspire new scenarios that the modeling group would request?

So, how does that fit into the timeline?

Initial Response: PNM

So, our intention is to share results along the way. You just mentioned that modeling is an iterative process. We are [going through that iterative modeling process] here internally.

Our goal is to be able to share all of the results on June 15. To the extent that we can't get to all of the results, we will share what we have and continue to provide updates to the modeling subgroup.

But I don't think that necessarily is a prerequisite for the subgroup to come up with what they think the best ideas [for modeling run requests] are as well.

New Mexico State University continued.

Yes, I would see it as two phases.

I'm sure that the subgroup can come up with some ideas prior to your presentation, but then your presentation will probably inspire need for a few more after that.

PNM continued.

Okay, absolutely.

New Mexico State University: Model for Long Duration Storage

Can you provide the 18-month special model for long duration storage?

PNM Response

Yes, that's on our July 27, 2022, presentation (link: https://www.pnmforwardtogether.com/assets/uploads/Slides-IRP-Technical-Session-4-IRP-Modeling-Updates-Techniques-Final.pdf)

It's mostly in pictorial form and it's the same model and data set that was used for all the other models, just using a different optimization window.

New Mexico State University: Green Hydrogen

Regarding purchase of hydrogen, does the carbon intensity law limit PNM to 100% green hydrogen while restricted to 0 carbon intensity?

PNM Response

Yes, that is the assumption we are making. In our modeling, in the cases in which hydrogen is assumed to come from a pipeline, we assume it is 100% green. Our cost estimates for hydrogen in those cases reflect this assumption.

In the cases in which we create hydrogen using electrolysis, that hydrogen is also 100% green: the model must build enough renewable resources to supply an electrolyzer with enough power to create the hydrogen that is combusted.

NM RETA: ELCC Diversity Benefits versus Individual ELCCs

Regarding ELCC diversity benefits over individual ELCCs, there is a new Astrape and E3 report done for the CA PUC report on Incremental ELCC (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf)

Is that new information that Astrape and PNM aren't already including?

PNM Response

Yes, we certainly can take a look at that.

I [would ask you to go back and have a look at] our January 17 [2023] presentation on our IRP website (link: https://www.pnmforwardtogether.com/assets/uploads/2023.01.09-Slides-IRP-PAG-Steering-10-EE-AEG-Astrape-Summer-22.pdf). There's a lot of more detailed presentation materials there on the

synergistic effects of ELCCs that we were capturing using our ELCC surface tool. We're not just doing marginal independent ELCCs but we are looking for that portfolio synergistic effect.

Western Resource Advocates: Imports

Back to Slide 4, when you were talking about the steps to modeling, SERVM, and then EnCompass, and back to SERVM, you mentioned how you treated imports. I think you said you use them in the first stage to develop the ELCCs and then they're kind of fixed in the second. So, can you repeat how imports are treated in this process?

Initial Response: PNM

Sure, thanks, appreciate the question.

So, when we're setting this up in step zero (we've got the box around SERVM there), we don't just model PNM in our reliability modeling. We don't just model the BA [Balancing Area], but we also model at least one tie line away.

So, we're modeling all the generating units in Arizona. We're modeling all the generating units in New Mexico. We're modeling all the generating units for PSCo and SPS and some of the neighboring utilities, as well as modeling a sink for some of the energy that Arizona would be selling into California --because we can't assume that all of the excess energy that's in Arizona would come to PNM.

And so we model all of these things and we then take a look at how many imports are coming into PNM, and we compare that [level of imports] to what we've experienced during times of extreme constraints.

One of the things that we've done within the model is say that during certain periods of time we're not going to accept the model generating so many imports because it's not something that our traders or our balancing area authority has seen when we get into these extreme conditions.

So, in the top 15 percent of gross load hours, we'll put a distribution on the ability to import into the PNM BA: between 200 and 300 megawatts. And then we get into the top [20 percent of load hours that occur between hours 19-22 during June-August], we drop that down to 50 megawatts. This limit is mainly tied to the extreme conditions in 2020 with the rolling blackouts in California, during which there

were time periods where we had open call offers on the market to try to import power--for $1,500 and $2,000 per megawatt hour we were not able to get more than 25 to 50 megawatts.

So, rather than put ourselves at risk by saying, “Well, we expect to count on more power during times of extreme constraint," we put that as a limitation in our model. Then, when we're calibrating to that 0.1 LOLE and reserve margin requirement, we're assuming that the perfect capacity needs that we would have to add within the PNM BA cannot be met by market imports, other than that 50-300 megawatts that would be allowable during those high load periods.

So then, when we set those requirements and then calibrate the LOLE standard to a PRM, we are implicitly assuming that you can import to those limits, because we're reducing the overall level of internal capacity requirements that we would have [if PNM had no access to markets at all] by the assumed level of imports.

In addition, we don't allow interactions with the market during the capacity expansion model, but we do have an economic market that we allow the units to interact with in the production cost modeling. That way, after we've designed a system that's best suited for serving PNM retail load, we do introduce the potential for additional benefits (that our customers would ultimately realize) from making certain off-system sales or economy purchases from the market, without overly speculating on the availability of imported power during peak periods.

Because we don't want to build to sell, right? We just want to build to serve load and then assess what additional benefits there might be for different portfolios from limited economic interactions with the market.

Does that answer your question?

Western Resource Advocates continued.

Yes, and two follow-up questions.

One: Do you have an incentive program for off-system sales?

PNM continued.

No. One hundred percent of our off-system sales, margins, are passed through to our customers through our fuel clause.

Western Resource Advocates continued.

My question was trying to get at: in this whole modeling process, [what are] the benefits of interaction with western wholesale markets?

So, the general question is: In this whole modeling process in the IRP process, to what extent are you reflecting the benefits of participation in non-PNM balancing area market?

So, I think you answered that.

PNM continued.

Yes, and we're reflecting them through some of the economic transactions and the reduction of the PRM or the calibration of the loss of load expectation (LOLE) while we consider some imports as a reduction to the amount of internal resources that we would need to carry.

So, that is a benefit.

With WRAP (Western Resource Adequacy Program) or with more fully designed western markets in the future that would have kind of a coincident planning mechanism that could further reduce our ability to carry resources internally or allow a more efficient interaction with the market for economy transactions, we'll just have to wait and see how that develops.

But that's certainly something we need to keep an eye on.

Western Resource Advocates continued.

So, that's not being incorporated into outer years in the IRP planning. So, a more active participation in wholesale markets. So, what you would model in 2025 [regarding markets] is the same as what you're modeling in 2035.

PNM continued.

That's correct.

Western Resource Advocates continued.

Okay.

May 18, 2023
Meeting #3

Member of the Public: Equipment End of Life

It seemed to me that there are a couple of areas that I think the outline really captures a lot--the vast majority of what we discussed and got it into a framework--but there are a couple of pieces that I thought weren't there: a mention of what happens to all this equipment when it reaches its end of life and what plan is going to be made. Some of these pieces of equipment are going to reach their end of life within this time frame already because they've been installed.

That was one point we had discussed at the May 4 [2023] meeting.

Initial Response: Gridworks

Thank you. Very helpful.

Working Group continued.

On the end of life and education portion, that is addressed in 2.2 and 2.3 of the [draft Statement of Need] document, so it is there.

Member of the Public: Public Education

I don't see anything here that says the need to communicate all of this information to the public. It is one of my critical issues that we have to figure out some way to inform the public about this, about how this transition is going to occur over the next couple of decades.

Initial Response: Gridworks

Thank you. Very helpful.

Working Group continued.

On the end of life and education portion, that is addressed in 2.2 and 2.3 of the document, so it is there.

InterWest Energy Alliance: Resource Adequacy

There are a couple things that I think probably need to be added to this [outline] as well--probably in the section on markets. There's also the [Western Resource Adequacy Program], which I believe PNM has committed to.

So, I think the resource adequacy program will probably be a significant driver that needs to be incorporated. Other significant drivers that I think--at least, I didn't see--[are] federal tax opportunities. Obviously, the IRA [Inflation Reduction Act] and the IIJA [Infrastructure Investment and Jobs Act] have added quite a bit of federal tax opportunities that I think are really important for utilities to try to incorporate as much as possible in their planning, as well as current federal opportunities for transmission.

Transmission is included in there, but I think the national interest corridors that's ongoing right now--there's several different rulemakings at FERC. I think there are a lot of ways to look PNM's opportunity for transmission that really should be incorporated in this process as well.

And the last thing that I saw [is] on the candidate resources. I don't think I saw geothermal in there, and I think that's an interesting technology that I think should be thrown in the mix for consideration.

Gridworks Response

Thank you.

CSol Power: Climate Change

I noticed that the area that the working group said should either be at the front or at the end is smashed in the middle, and that is social equity, the fact that we're working against, basically, impending disaster: climate change.

And that [needs] to either set the tone or bring everybody [together] and push everybody forward.

Gridworks Response

Thank you for that.

ENMRD: Renewable Natural Gas

It seems like in the last meetings PNM's kind of negated [consideration of] renewable natural gas as a transition fuel. And I haven't seen a legal reason for that, because, as we discussed last time, it actually can be used as a zero-carbon resource under the ETA.

And, if cost is a concern, that's a very easy transition from the current thermal resources, and it really would add to the resource adequacy piece in a very inexpensive way. Plus, it has the added benefit of taking care of some of the feedlot gas that we have in our massive feedlots in the eastern plains.

So, there are multiple benefits in looking at that. And I think it should be at least looked at. And if it's not a legal option, then that's fine but I don't see where it's not right now.

So, thank you.

Initial Response: Gridworks

For the benefit of all our stakeholders, will you please define renewable natural gas?

ENMRD continued.

Any methane that's captured from a waste product: effectively it could be from a landfill or from a digester or a wastewater treatment plant.

But the ETA [Energy Transition Act], as everybody looks at it, there was a last-minute amendment to that on the zero-carbon resource standard, mainly for the Albuquerque wastewater treatment plant that generates power with their bio gas. It doesn't stipulate that it has to be the gas produced on site and burned on site; it just says you must capture X amount of methane and then burn that.

So, the zero-carbon resource doesn't mean zero carbon emissions. It means it's offset by the methane that's captured somewhere else.

I think that is something that needs to be looked at because it would be a very easy fuel switch and we have massive feedlots that are emitting methane right now that have no place for that methane because it's not valued as a resource.

NMPRC: Draft Loads and Resources Table

Thank you [Gridworks] and the rest of the group for this work.

[Are you] asking or suggesting that PNM at this point provide their draft loads and resources table per your outline?

You're suggesting that that's a key element and PNM has that document in draft form now. And so, would that be something you want to see, sooner than later?

Gridworks Response

So, our next steps are going to be to start to fill out this outline. And so, if they're the entity that has the appropriate information, the answer would be yes, that that information would come forward.

NMPRC: DSM

[I have a question], which is giving more detail and specification on DSM because that element of the loads and resources table has also been done and then it's called out in the IRP rule to specifically address that.

Gridworks Response

Yes, so they would bring forward their DSM portion.

The working group could also, in its preferred section, ask questions or bring in information that it would like to see studied that's beyond or different than what PNM has.

NMPRC: Green Hydrogen

[Concerning] green hydrogen that's on the outline that I believe [the working group] said came from PNM directly on resources that it's studying, I just noted that, or it was pointed out to me by PRC staff the other day, that green hydrogen's not defined in the IRP rule as a renewable energy resource.

So, is that a question at all for the working group or not?

Gridworks Response

Great question.

Form Energy: Upgrade of Existing Fossil Resources

I just wanted to dig into--I think there was one portion of the document which stated--the exploration of cost-effective repowering or upgrade of existing fossil resources.

So, I wanted to kind of encourage the group to also consider not only retrofitting existing combustion resources with hydrogen or carbon capture as a suggested kind of [by the current language] but to also consider potential retirement of these resources and replacement with storage and renewables as a form of firm capacity for the system.

Gridworks Response

Thank you.

CSol Power: Geothermal Resources

I agree with [Form Energy] that geothermal needs to be included in the resources. Wind and solar are already being used. So why isn't it being included?

And then aeroderivative gas is not renewable. Well, they tried to get that passed as renewable in this past legislature. It is not.

Initial Response: Gridworks

Yes, and I think someone put in the chat that geothermal is in a list of resources.

CSol Power continued.

When I looked at this outline and I looked at PNM's list of resources I did not see geothermal, but I could be wrong about that.

Geothermal is in Lordsburg. It's a very small plant … but it is something that could be developed in New Mexico.

Gridworks continued.

Yes, I mean, in the list of resources that PNM is going to consider going forward, I did not see geothermal. Someone in the chat said it wasn't there.

CSOL Power continued.

No [it's not in the list of PNM resources going forward] because it's already part of their assets.

Gridworks continued.

I think it could be. ENMRD mentioned in the chat geothermal always was in the current mix.

ENMRD continued.

Yes, they have it in their current PPA's.

Gridworks continued.

Yes, great. Okay.

Lincoln County LANRAC: Costs/Benefits of Developing Resources

I want to thank you for inviting us to be here. This is the first meeting [we have] attended.

As far as the Statement of Need, it covers a lot of aspects that I thought were essential, but when we address both the environmental costs and benefits, we need to assess it for the entire life of the program from cradle to grave, if you will.

And this outline does a lot of that, but it does not address the cost and benefits associated with the development of the resource as well as the deployment aspects of each resource.

You will bear in mind that a lot of the benefits and cost during the operation and maintaining the resource is all well and good, but if you blow up the environment at the beginning to create the resource, and then you pull it up again when you retire the resources, it becomes a wash or a negative effect.

So, you need to include the entire life cycle of a resource.

Thank you.

Gridworks Response

Thank you.

We would encourage you, if there is a place in the outline that you think that is most appropriate, if you want to send verbiage to us, that would be great.

SWEEP: Energy Efficiency, Demand Response, and Load Management

I had a couple points.

One: I think it'd be good to differentiate for the energy efficiency and demand response that which is already being pursued and implemented by PNM and that which they've identified through their consultants as incremental and available that they are not pursuing.

And then similarly--I don't know if it needs a new category or where it would go--thinking about load management effort, dynamic rates, and how that will change the load shape that these resources are trying to meet.

So, since we're looking at a long-term view of the resource need if PNM is successful in implementing time of use or other kinds of dynamic rates, then to me we don't want to overbuild resources. To me, that will shift away from that hour

If you want to make edits [to the outline], the load management could go in the preferred section. So, after all the resources are listed, then things like Time of Use ("TOU") rates or load management strategies related to tariffs would be an option.

I'm not sure how you model that, but we'll let PNM figure that out.

REIA: Cradle to Grave Concept for Fossil Fuels

I also want to comment on the cradle to grave concept.

That talking point has been used by people who are advocating for the continual use of fossil fuels, but I do want to say that that whole concept is way bigger than renewable energy resources.

So, the concept of cradle to grave would apply to automobiles, to TV sets, to laptop computers, paint cans--pretty much every product that is made and used.

I think we should keep in perspective: that there's a much larger picture to this concept.

Gridworks Response

Thank you.

June 1, 2023
Meeting #4

InterWest Energy Alliance: Correlated Gas Outages and Transmission Options for Modeling

It was important to talk about this during the Statement of Need discussion, but I appreciate the update that was sent out. Just during the meeting. I had the opportunity to review the outline and both of the [issues] that I think are very integral to InterWest, which is: correlated gas outages and transmission as an option for the IRP to pick.

I think both incorporated in this update that weren't in the version sent out yesterday, so I appreciate that.

And I guess I just wanted to offer for the Statement of Need, the request for information, both of those. We had prior submitted into the process [earlier] written comments for transmission as well as the presentation [for stakeholders by a consultant] on the correlated outages. So, both of those are available.

I don't think we'd really be able to offer any additional information on those, but I would appreciate the Statement of Need team really having those at their disposal.

Gridworks Response

Great. Thank you. We'll be sure that all those materials, those four documents that we received from InterWest, are loaded on our Gridworks website.

We'll be sure that material is brought to the benefit of the working group on Statement of Need, so thanks for reminding us about that.

NM AREA: Modeling Decisions

[In reference to the modeling run request list of Slide 4 of presentation.]

I think [PNM] said [they] can't [extend Valencia and Reeves]. I didn't really understand that.

Initial Response: PNM

[Regarding Valencia]. we are not going to put a specific RFP bid into the IRP.

NM AREA continued.

I guess my thought on that is that if you retire [it], then the model has a hole. So I don't know how to do it in the modeling, but make it so that there's not a hole that it's filling, right? Either just put in a generic gas plant or whatever.

Working Group continued.

That's what [PNM is] doing. right?

NM AREA continued.

You don't have to model the RFP, Just make it so that the model's not filling in for a hole.

PNM continued.

So, that's why we said we think that's one of those where we need to sit down and talk about the implications and what we're trying to accomplish there.

If you have a scenario where Valencia comes out, and it gets replaced by similar sized gas plant, there's no way you could come to any other conclusion than an extension of Valencia is certainly a possibility,

but until we get to an RFP analysis, we're comparing it to another set of resources that would compete against. Putting in just a single RFP bid against generic data doesn't provide useful price information.

NM AREA continued.

[I was just asking about the ones you are already doing.]

Working Group continued.

We included them because they're not, I believe, precisely what PNM is already going to do, but they were asked by several stakeholders. That's why we included them in the list. Several people asked about Valencia. Several people asked about demand response.

NM AREA: Access to Data

[Will we have access to the Venue data dump?]

PNM Response

The answer is yes, meaning that the confidential data and the data dumps will have all of the hourly loads in hourly market prices and other things like that.

It's just going to be in a model format, so [it'll] take a little bit of working from the stakeholders to go and understand that format and pull the information they want out.

If you want to have the most granular set of information, if that's meaningful to what you need to do in order to put together a model request or something else, that's where it will be. But [we're] not going to go through the process of taking that data dump and separating it apart into specific elements. It's already there. You just have to look at how to use it.

June 15, 2023
Meeting #5

Member of the Public: Consumer Education

First of all, I'd like this [Statement of Need draft] document to have page numbers. I think we also need revision dates on this as we make changes in it because it's going to be really hard to track otherwise. So, that's to the housekeeping piece.

There's a section in the goal statement that I'd like to comment on. I think it's Item Four in the goals [Slide 3 of 6]. It's the one that deals with education--"Consumer Education" and "NIMBY." I think that's really buried.

To me, "Consumer Education" doesn't even address the public information need for the whole process of energy transiting off of fossil fuels. I would like this that section to be developed in a much different way.

I'm willing to work on that with others. I've indicated that in the past, but to me that's a very important area. I'm not even sure it's within the context of the IRP itself to address that issue, but I think it is in the context of this group to address it.

Initial Response: Gridworks

Thank you. I know you have asked some folks for input and haven't gotten it. We may be able to address this in a introduction to the Statement of Need to be able to call out that education of the public about what's happening around energy generation development is important.

So, I think we can pull that out and make that more important or stand out more.

Thank you for the comment.

Member of the Public continued.

You're welcome.

Office of Sen. Heinrich: Reliability

My comment has to do with the reliability under goals. Quick question, then I'll state my comment.

Was reliability mentioned in the context of the bulk power system in terms of what NERC enforces with generation and transmission or is it also with the distribution side, the SAIDI, SAIFI, etc.

And then I have a question following that.

Can anybody answer what context the reliability standards were discussed in?

Initial Response: PNM

Typically, in the IRP, we don't get down to distribution level modeling. It's done at the bulk transmission level. So, the reliability and resiliency discussions and previous IRPs have been on NERC standards, overall LOLE planning type requirements as well as operating reserves.

We certainly can discuss a little bit, down to the distribution level about maybe what SAIDI, SAIFI etc. is, and the Statement of Need does call out--that we could talk about within the Statement of Need in the context of new resources or what we believe the most cost-effective portfolio will be, what additional improvements might need to be done to the transmission and distribution system.

In terms of modeling down to that level. that is not something that is going to be incorporated in this IRP, though.

Office of Sen. Heinrich continued.

My comment on the reliability on the distribution level is: It may affect because PNM is

vertically integrated you have all three, there may be some, with regard to the Statement of Need--in terms of what new resources are you procuring and why, and how is it going to affect ultimately

reliability--I think having some mention of the reliability in terms of SAIDI, SAIFI, etc. and is that being done at a granular enough level to do a couple things.

One is to ensure what circuits are poorly performing. Is it down to that granular level?

I know a lot of those are reported on the entire system level. But also, the other need I noticed equity is on there. I think that's important.

Number two, the public interest equity. Being able to ensure the equity/equability of the reliability of these systems. … I just think it's important to say is the reliability on the distribution system equitable and there are ways to maybe monitor for that if it's not already being done. And then from a resource perspective for this Statement of Need. is it within the scope of this? I'm not sure, but I just wanted to throw out that there might be some distribution level reliability issues that could help just overall reliability in terms of the granularity of how the data is reported, but also on equity.

Thanks.

PNM continued.

I definitely appreciate your comments and for those folks who are unaware, there is going to be a reliability workshop at the PRC [Public Regulation Commission] special open meeting tomorrow [June 16] where all three vertically integrated utilities in New Mexico are going to be talking about distribution reliability.

New Mexico State University: Load Forecast

I have a comment on [Slide 3 of 6] "Current and Expected System conditions/Load Forecast."

I'm not sure if the energy efficient technologies adoption will be considered and also Distributed Energy Resource ("DERS"), like rooftop solar, just use the end storage considered because those are highly driven by like the importing tax and the cost of those devices. And the DERS will have a significant impact on the net load forecasting.

So, I'm not sure that is considered here or considered somewhere else?

That's my first comment--on the load forecast.

And second is that I'm not sure it's like a stability or a transient analysis to be considered as the system will get much lower inertia as we become an invertor-based system and some technologies like Pumped Storage Hydro (“PSH”), they have different turbine technologies and the some of them they can provide you more stability and rapidity perks, like it can provide inertia with different turbine technology. And the cost of those turbine technologies can vary. So, some could be triggers more expensive, But without modeling the trend and [using] stepping analysis, the benefit of those new technology may not be appreciated in some of the studies.

Gridworks Response

So, one was modeling on the turbine technologies and it's capabilities to provide voltage support and some other things. And the other one was related to load forecasting and if energy efficiency [DER?] storage are being considered under electrification.

So, thank you.

NM State University continued.

Thanks.

REIA: Including Distribution in the IRP

Just a little quick response on the IRP not including distribution. My observation is nationally more and more IRPs are actually including it in some format, and maybe I'm missing something, but isn't it integrated resource planning?

I think distribution is a resource. So, I would suggest that we should at least look at including distribution into the planning.

Thank you.

Initial Response: Gridworks

I would love to task [REIA] with some stuff. So, I would appreciate it if you would take a look at this and see what you think needs to be included. It's certainly an evolving area, so appreciate any thoughts you can provide to [the modeling subgroup].

NMPRC continued.

[Pointed out that] the IRP rule does refer to consideration of distribution planning.

PNM continued.

[NMPRC] is referring to in the second bullet under Statement of Need [Slide 1 of6] It does refer to expanding or modifying distribution grids as one of the things that could be considered an overall defining what the Statement of Need relative to new resources would be. So, we would want to think it about context. It's not an entire distribution planning exercise.

Gridworks continued.

Right, and as somebody mentioned earlier, this is an evolving field, right? We need to be looking in the future more at the distribution system because more of our resources are going to be on distribution.

So, we're not going to solve everything in this round. This process is going to go on. So, I think we need to address it and figure out an appropriate way to include it in the Statement of Need.

PNM continued.

Absolutely. Just in terms of the way that the models have currently been set up and what we can look at. Anything that's done at the distribution level will have to be thought of in a way where it's aggregated to bulk transmission in order for analysis, we can certainly think about ways to, to improve

things going forward, but currently the modeling capabilities are separated between bulk and distribution levels.

Office of Sen Heinrich continued.

Is it possible, in addition to modeling in the IRP and in particular for this Statement of Need, to suggest that data collection and use would be beneficial in terms of distribution level reliability. I agree it's hard to model a lot of these faults that occur on the distribution system, but I'm really interested in how data can be collected at a granular enough level to help inform resources, not only distributed energy resources, but even going back to the bulk generation and transmission and, then again ... equity.

Is reliability being disproportionately or the non-liability affecting certain populations more than others? Do you think data collection and use is within the scope?

Gridworks continued.

I think this is a longer conversation and it's great that [it's been raised.] The statement of the group can consider that as part of the discussion about future actions to monitor reliability metrics at the distribution level. Let's not do the conversation now, but I think it's an important capture of an idea to put into the document.

NMPRC: Nameplate and Effective Capacity of the Base Technology Scenario

My question: Is that information in the database that's available through VENUE or is that something that will be made available?

Initial Response: PNM

So, we will be posting the output files for all of these cases to VENUE shortly following this meeting and anybody who's requested access to the public data will be able to go through there and get whatever they need out of it.

Gridworks continued.

And those inputs on nameplate and effective capacity are part of the outputs. That would be part of that data set, right?

PNM continued.

You'll be able to see for every resource both, it's nameplate capacity as well as its effective capacity, recognizing that the effective capacity of a resource changes year by year as the overall portfolio changes year by year, following those ELCC curves that we've talked about numerous times throughout these presentations,

So that information is going to be specific to each scenario, which is why it's an output and not an input.

Gridworks continued.

Great. Okay. Thank you.

PNM continued.

On the input public data there were some examples of the overall ELCC surfaces that folks could kind of start to understand the interactions between the different technologies. On the outputs here you'll actually see for the given scenarios, for the given years, as the portfolios change over time what the effective capacity of those different portfolios are on a year by year and a portfolio-by-portfolio basis.

Gridworks continued.

What's your plan for posting the preliminary result?

PNM continued.

We'll have the outputs that support this presentation posted later today, along with [the information] for those people who signed the NDAs--we'll post the full confidential inputs, which will have all of the hourly data and other such things as well.

Gridworks continued.

Great, Thank you.

REIA: Renewable Production/Carbon Emissions

On the slide that shows the renewable production increasing and the carbon emissions going down, [REIA] wanted to point out that it might be confusing because the minimum and maximum are reversed between those two.

So, people need to think about renewable production going up as positive. That's why the min and max are there. And then carbon intensity going down.

That might be confusing to people, so folks are encouraged to study that carefully.

REIA: Community Solar

I don't think I saw the 125 megawatts of community solar that has been allocated to the PNM system in any of these charts and I was just wondering if you could comment on that.

Initial Response: PNM

Sure. That 125 megawatts is included in all of the scenarios because it's been identified; it is a planned resource. So, we didn't show that here. We wanted to just capture here the things that the model chose from the suite of generic resources. That's not a generic resource.

Similar to energy efficiency and demand response and all of the other changes that have been approved and are currently under construction. all of that's included in every scenario.

REIA continued.

Okay, thank you.

Also, kind of related to that, I'm assuming you don't include in terms of generation, but you're looking at more as demand reduction, any increases in behind the meter solar.

PNM continued.

If you were to go to the load forecast presentation from December 2022, you can see specifics on behind the meter increases. But if you want a quick summary, we expect behind the meter PV additions to grow from their current levels up to almost 1,000 megawatts between residential and commercial by the time we get to the end of the planning period.

That is modeled as a load reduction in the current scenarios, but as we've also discussed, we are likely to be doing a [DRMS] type scenario where we can tie the behind the meter PV to some behind the meter batteries and see what type of offsets that may reduce utility investments by.

REIA continued.

Great. Thank you very much.

REIA: Community Solar

I don't think I saw the 125 megawatts of community solar that has been allocated to the PNM system in any of these charts and I was just wondering if you could comment on that.

Initial Response: PNM

Sure. That 125 megawatts is included in all of the scenarios because it's been identified; it is a planned resource. So, we didn't show that here. We wanted to just capture here the things that the model chose from the suite of generic resources. That's not a generic resource.

Similar to energy efficiency and demand response and all of the other changes that have been approved and are currently under construction. all of that's included in every scenario.

REIA continued.

Okay, thank you.

Also, kind of related to that, I'm assuming you don't include in terms of generation, but you're looking at more as demand reduction, any increases in behind the meter solar.

PNM continued.

If you were to go to the load forecast presentation from December 2022, you can see specifics on behind the meter increases. But if you want a quick summary, we expect behind the meter PV additions to grow from their current levels up to almost 1,000 megawatts between residential and commercial by the time we get to the end of the planning period.

That is modeled as a load reduction in the current scenarios, but as we've also discussed, we are likely to be doing a [DRMS] type scenario where we can tie the behind the meter PV to some behind the meter batteries and see what type of offsets that may reduce utility investments by.

REIA continued.

Great. Thank you very much.

CSol Power: Capital Costs

In the modeling meeting last week, there was another term that I wasn't familiar with that I thought was included. I'm just wanting to make sure what all's included in that present value

PNM Response

It's all costs. It's up-front capital costs, ongoing capital expenditures, O&M, fuel, taxes, any tax credits that we would receive, authorized rate of return, all of the cost of the utility system on a revenue requirement basis are included in that present value of revenue requirements.

Gridworks continued.

And I think that the announcement that [PNM IRP] made early in this presentation, that a deeper dive presentation on these results is scheduled for next week [June 21 meeting was cancelled], is a great place for folks who have additional questions or comments and want to dig into this.

Office of Sen. Heinrich: Uncertainties

[Regarding] Slide 11: I know these are preliminary results, but they're basically a number of how much storage and also resources are needed. I'm just wondering: How is uncertainty captured in these different scenarios and technologies that are being evaluated?

I'm just thinking that some of these technologies and scenarios may have very uncertain condition performance behaviors. I didn't see any mention about how that's captured and reflected in the results to determine next steps. I saw something about cost and certainties, but in terms of these scenarios. What are the inherent uncertainties of carbon capture and how that influences how much generation or things you can produce, et cetera?

Initial Response: PNM

So, all of these are just deterministic runs using our base, current trends, and policy inputs, and so we're going to get into uncertainty modeling as we do deeper dives and flesh out the portfolios more going forward. So right now, this is all just kind of a static deterministic run to compare the technologies against each other. We're multiple cases of combined technologies, more complex scenarios getting into uncertainty modeling as we move forward.

Office of Sen. Heinrich continued.

I think that's the right way to do it. I just wondered if there's any preliminary assessment of, maybe without getting the actual results, just saying there are huge uncertainties in how this scenario plays out or something just to indicate, preliminarily, if that's the case.

When I read a table that has--I think it was three or four significant digits--at least my perception is that's the answer. I always caution against that: It's like, there might be huge bands that even though it's maybe five percent less than this scenario or whatever it is, the metric is, I think it's always important to just try to capture uncertainty.

PNM continued.

Yes. Thanks.

NMPRC: Combustion Turbine Construction

For the combustion turbine scenario service in 2032: When would you start construction?

I don't know if it's a utility build or if this is an RFP, or if that specification enters in at this point.

Initial Response: PNM

We are agnostic at this point to whether it would be a third-party asset or utility build or modeling everything using utility revenue requirements and utility cost structures in terms of when construction

would actually start. So, that slide did not indicate that it was a 2032 resource. It indicated that it could have been added between 2025 and 2032, you'll see the exact result.

We can't go and just build a combustion turbine without first going through an RFP process and then submitting an application with the [Public Regulation] Commission. The construction time frame for a combustion turbine is typically two and a half-ish years or so, depending, once you have all the permitting and regulatory approvals done**.**

NMPRC continued.

Could pop up in the Action Plan.

PNM continued.

Well, the Action Plan, being 2024 to 2026, and the fact that we already have all of our resource procurements done for 2024 and 2025, and we're currently evaluating the RFP for 2026 that will be filed before we file this case, it's unlikely that it would end up in an Action Plan.

NMPRC continued.

Okay. Great. Thank you.

June 29, 2023
Meeting #6

Stakeholder

Were there any trends up or down towards more variability that you could carry forward?

Form Energy Response

Yes. That's a very interesting question.

That's not something that we investigated within the scope of this study and we're not climate modeling experts. But I think generally there is an understanding that with climate change we do expect to see greater variability in weather and a greater frequency of extreme weather events.

But as it pertains to things like renewable lulls, we didn't necessarily have any findings on that front.

Stakeholder

[Paraphrased] Can you be really clear where you can, where you think PNM is with their modeling right now? I think PNM has a three-step process with their modeling; which of those approaches is leading up to 8760? Or is there something in between?

PNM Response/Comment

[Paraphrased] So, our approach is somewhere between the capacity expansion model. We are using a linked-sample day approach that then is put into a full 8760 optimization for production costs, advanced purposes, to make sure you capture the full effects of the longer duration energy security into a weekly full year commitment approach that ensures that the dispatch of the long-term long duration energy storage is maintained based rolling forward.

And we used a 40-year historical weather approach and our reliability model for multiple calendar years in that evaluation and for developing our ELCCs.

Form Energy Response

I could just add a little bit to that. I just want to be clear about what was presented here, which is these are modeling techniques that are really applicable to a very future decarbonized energy system but right now a lot of these modeling approaches have not yet been implemented [as] industry standard tools.

So, this is an area for active model development.

I think PNM is using the best-in-class tools and methodologies that are available today and it's on us as an industry as a whole to really figure out how we can start to incorporate some of these techniques, like 8760-hour optimization, into tools that can really be used in an IRP context.

So, it's one thing to perform this type of modeling [as] kind of an academic study or research study but the constraints on modeling in an IRP context are very different.

I think that's something that's important to keep in mind.

Same Stakeholder continued?

I'm not so sure I got the answer there. My interpretation of what PNM said is that its somewhere in-between your middle approach, which was a linked analysis, and the full 8760 and your recommendation is to do more of a full 8760.

I don't get the details, but I wanted to move on to a second question which is the 40-year wind history because maybe it was my misperception, but I thought that PNM's 40-year history was somehow repeating what they've seen historically at their own wind farms which have only been in operation since something like 2005 so they couldn't go back to 1980. Anyways, can you tell me where your wind data came from that starts in 1980?

Form Energy continued.

Sure. So, this data set here was based on historical wind speeds that are available in the NASA MERRA reanalysis data set.

I'm happy to talk more about how we specifically got that data, but yes, correct.

I think it's important to acknowledge that the NASA data set, for example, may not account for some of the actual site-specific operations, too.

So, this data should be taken with a grain of salt.

Same Stakeholder continued?

Is the scenario produced by minimizing costs over multiple weather years?

We assess that that wasn't [our representative the money generates the scenarios based on the interval data. We can generate them moments and hours of play how possibly think that wasn't already approached to them just the rest of them?]

Form Energy continued.

Yes, so if I'm understanding you correctly, you're saying that what we've shown is that historical weather years can vary significantly and so, … like this slide [Slide ?] for example, we're just picking one weather year. And so why did we pick this one weather year? Is that right?

Same Stakeholder continued?

[Paraphrased] Why is it that you just generated one scenario]

Form Energy continued.

So, in this specific example here we just wanted to show one representative weather year. But in the scenarios that I presented here, these are based on a co-optimization across multiple weather years. So, we're not picking one just one scenario but rather we are integrating multiple scenarios of weather conditions into the capacity expansion optimization simultaneously.

I think it is important, though, that when we talk about identifying representative scenarios or representative days [we ask]: What does representative actually mean? Are we actually capturing all of the variability that exists in all of the original scenarios?

I think that's an area for active modeling development and research.

[Speaker and question indecipherable.]

Form Energy continued.

Yes. I can just give one quick response, which is I think all of the points you brought up are very valid and very important to think about in resource planning.

But, as you alluded to at the end, ultimately, we cannot capture every single source of uncertainty in the system or else the model size will blow up.

So, we have to make informed decisions on "What are the variables that really drive the portfolio decisions the most?" I think, based on what we've seen capturing weather variability, for instance, this is one of those variables that can really shift the needle when it comes to resource planning decisions.

Stakeholder

Also, then, how would we interpret and understand [the results of the modeling as related to this IRP?]

Form Energy Response

Yes, that is a good question.

I think for this IRP cycle, again, the PNM team has used the best available industry standard models and approaches that exist. So, I think the point of this presentation was not to say PNM should have done XYZ in this last IRP cycle. This is more about highlighting where modeling practices need to shift in the industry as a whole moving into the future.

So, I'm hoping that some of the things we're talking about now can just spur conversation and further discussion in the future on how we can start to incorporate some of these ideas in an IRP context.

Stakeholder

We talked about variability and resources over time. Does variability also exist in resource generation across space, geographically?

Form Energy Response

Yes. It definitely does.

In this case study, we modeled Eastern New Mexico wind and Western New Mexico wind as separate resources. And then, for solar, we just used solar data based on Northern New Mexico, using locations where the majority of PNM's existing solar facilities are.

But it is an important point that there is geographic variation. The problem is, again, if you're trying to account for every source of variability and uncertainty in the model, the model size becomes intractable.

And so, what really matters is what is going to drive the resource decisions. I think it requires balancing both of those and trying to capture the temporal variability as well as the geographical variability without sacrificing too much on either one.

Stakeholder

How did PNM come up with its ranking criteria [Slide 16], for example, reliability 45 percent?

PNM Response

This is a great question.

I assess that means more like: Why did we choose 45 for reliability? Why is reliability a criteria?

To be frank, we sat down and started discussing ideas. When we think about it, we still have the Public Utility Act which requires us to provide safe and reliable electric power at the lowest reasonable cost. Those are still the primary things we have to do.

The Energy Transition Act then came along and said: PNM you're required to go carbon free by 2040.

All of the portfolios here that we're designing are going to be able to meet the RPS and the carbon requirements, and we want to do so in a reliable and low-cost way. So, we put the greatest emphasis then on reliability and cost.

[Regarding the weighting for carbon emissions criteria:]

Each one of these portfolios meets the required carbon emission intensity requirements. As we go forward, they all meet zero carbon, they all meet our renewable requirements.

So, when we're saying, "Well, what does this particular measure of carbon tend to mean?" It's which ones are doing it quicker? Which ones are doing it faster? Which ones are doing it [at a] more accelerated [pace] than what the state requires.

Because each of these [portfolios] is doing what's required, we didn't want to go ahead and say, "Well, we're going to put this at 50 percent" because we're already meeting the requirements in every single portfolio. This is kind of the incremental on top of what's required, which you already know: We're going to go carbon free.

Stakeholder

On the same slide [Slide 16], how is reliability determined? Is it a specific PNM value given each resource type? [Tell us] more about reliability—obviously you mentioned the metric of loss of load equivalent and unserved energy. Can you talk some more about how is reliability determined?

PNM Response

In this sense, reliability is the measure of the incremental loss of load associated with, or unserved energy associated with running, on a deterministic basis, the P50 capacity expansion under a P90 weather forecast.

Keep in mind that this is just scoring for Phase One and Phase Two.

In Phase Three, we're going to be examining portfolios under multiple different futures, multiple different sensitivities, and then we're also going to be doing both a full stochastic reliability and resiliency analysis.

So, the relatively simpler approach here on reliability, just measured by a deterministic EUE, is going to get replaced by something way more complex going forward.

But when we're looking at trying to say "Well, how robust are these portfolios--at least on a deterministic basis," the measure for reliability is how it performs on an expected unserved energy basis when we add on the P90 loads to a portfolio that was only designed for a p50 case.

Stakeholder continued.

I guess I'm curious if you can get down the level of understanding which hours that happens in and which resources would be running.

[If] there's an energy [demand that you're not meeting], which hours of the year [is] that occurring in, [and] which resources would you be expecting to meet that demand that can't? So, what would be your options to fill that gap?

PNM continued.

Are you saying if we hypothetically were to add more resources, what would we add?

Stakeholder continued.

Yes. What would be your options to meet that [unserved energy] [versus what is currently there] and not serving the load?

PNM continued.

So, if we look at the heat map of risk hours, until we get way out into the future, [risk is] predominantly going to [occur in] hours 19 through 21--in June, July, and August. Solar is not there at that point. Wind is.

We'll talk about this in the deep dive.

When we are seeing loss of load, it's typically in weather years where you do see a wind drought during those time periods. And so, what we would be seeking to call upon is energy storage, provided there's actually still state of charge in energy storage devices, thermal resources, demand response.

Stakeholder

Is there a certain reliability threshold similar to [that]?

PNM Response

Keep in mind that the capacity expansion model was run on a p50 weather forecast.

So, under the p50 weather forecast, each portfolio is designed to meet that .1 LOLE. But when we throw in the P90, we're putting in something that's more extreme, more in the tail, and that portfolio wasn't designed to meet that specifically.

[The question we're asking is:] Do some of these technologies or do some of these portfolios happen to reduce the risk of unserved energy better than others?

Stakeholder

Is the carbon price cost included?

PNM Response

Yes, there is a carbon price included in the modeling. It was in one of the previous presentations. It's our mid-carbon price. It's in the public data set.

It is included in all this modeling, so it is going to influence the resource planning decisions in terms of new investments. It's going to affect the dispatch of the resources.

When we're talking about the carbon piece here, in terms of the scoring matrix, that's just measured on tons of carbon, not a price associated with carbon.

Stakeholder

Are there other intermediate targets?

PNM Response

That's a great point to bring up and it probably draws a distinction between what you heard in the Form Energy presentation versus what we're doing.

We're modeling 20 years—20 calendar years.

I believe what Form Energy was talking about was just saying, "Well, let's throw away what happens between 2023 and 2039, and if we can just get to 2040 with a clean slate, where would we be?"

We're modeling all 20 years that lead up to that. So, if you look at the outputs from any of the modeling or anything, you'll see how the portfolio evolves over time, how the dispatch changes over time. You'll have carbon intensity of renewable. We'll have everything for each year of the 20 years.

What we're really doing is doing a capacity expansion run that will set the portfolio over 20 years. Then we're dropping down and doing an 8760 optimization to determine the way we think the long duration storage will operate, doing a full year optimization at a time rolling forward to get the energy storage production profiles.

And then we'll do a rolling two week over the next 20 years--always hourly 8760--to determine how the unit commitment will work with some of those resources that do have minimum up times, minimum down times, things like that.

Stakeholder

It appears that you consider the combustion turbine (CT) hydrogen as technology-ready. Please explain CT hydrogen as technology ready and comment [on that].

PNM Response

Near term, [the CT] is 100% technology ready. The risk is, really, does the hydrogen economy materialize or is there some other non-carbon-emitting fuel that would be able to be worked out.

We've heard some folks from [EMNRD (Energy, Minerals, and Natural Resources Department)] [say they] think there's enough landfill gas there. Or, if that's not there, does renewable natural gas develop?

So, it's a little bit less risky because you have a much longer time before you get to 2040 than earlier in time.

We understand there is some risk there. We're open to hearing suggestions on how you may want to weight that, but we think that because there's a much longer time period there

associated with it, that the relative risk is pretty low.

Stakeholder continued.

[My questions is about the] risk associated with natural gas prices - higher and volatility - for essentially all those Phase Two scenarios, because assessing that they may just be gas technologies that don't convert hydrogen

and then also whether you modeled or considered the stranded asset potential associated with those gas technologies.

PNM continued.

The other thing I'll add on here is there are currently combustion turbines that can burn 100 hydrogen today. So, we know that the technology can happen. The question is whether it gets there cost effectively.

In Phase One and Phase Two, we are doing our analysis using our current trends and policy future.

When we get into Phase Three, we'll start introducing high and low gas prices and other things like that.

In terms of stranded asset costs, we've talked internally about one of the things we might want to do is say, "Well, what happens if we made some investments in CTs and then in 2039 we make an assumption that you can't use them anymore and you have to replace them? What will that do?

At that point in time, you're going to have better technology characteristics. In the future, prices may come down, so there may not be a difference.

We don't know yet. We haven't finished that analysis.

Stakeholder?

I really appreciated that last verification of the intent of the presentation: How [this approach] could be used in this process. And I think it also helps to show that, particularly with storage, [this] approach to modeling can really impact how storage is built.

[This shows how, in what ways, long range of storage [can be used] as sensitive to modeling choice.]

I [also] have a couple of clarifying questions.

In your 8760 modeling, were you allowing the model to select long duration storage or were you hardwiring in some amount of long-duration storage and then allowing other resources to fill in?

Form Energy Response

That's a great question.

So, we were performing a true least cost optimization where we provided all of the candidate technologies and allowed the model to select the optimal capacity of each technology without forcing in any technology.

We included the full range of long duration. Only a couple were selected by the model, but we did include the full range of five or six long duration storage technologies, for example, that were in the PNM IRP as well as some of the other technologies.

Stakeholder continued.

In terms of the testing of the linked days, is it correct that you were only looking at two days maximum or two days you linked because I wonder if you were to do a version of this with six or seven days linked, if that might be a more cost-effective approach that approximates for the 8760 results.

Form Energy continued.

In this link day approach, [we created] representative weeks where we took the two representative days for each month and had three days of the peak day and four days of the off-peak day and used that to construct like a linked week. And then we linked all of those weeks together for each month to construct an entire year. So, they were linked into a continuous 8760-hour time series and That's what was modeled in this study.

One thing I think that I should mention when it comes to day sampling and linking, is I think there is definitely literature research to support that some sample day methodologies can be effective, but what really matters is how are we doing the sampling: What is being captured in those sample days? If we're just taking like a peak day and an off-peak day that might not actually be capturing what really matters in driving resource decisions.

And so, there are more advanced techniques that can be used to identify periods of the year that really represent--like through clustering algorithms and stuff like—the full range of resource dynamics.

Stakeholder continued.

It's short yes for the 8760-modeling approach. How would that fit into a competitive bid evaluation if PNM gets like 400 bids?

Gridworks continued.

So, I think that's a PNM question not a question for [Form Energy].

July 27, 2023
Meeting #7

NM PRC: EnCompass Capabilities

Does EnCompass have the logic capability to capture the synergistic effects between wind, solar, and storage? The 2020 IRP noted that EnCompass did not have this capability.

PNM Response

Yes, we've incorporated new ELCCs in the EnCompass modeling that do account for diversity benefits between solar and storage. We found that there was not a lot of correlation between wind and the other two. So, yes, those diversity benefits are captured.

Western Resource Advocates: Cost of Carbon Emissions

Shouldn't the social costs, like carbon emissions, be discounted with a social discount rate, like three percent rather than 10 percent—and after that can you address that to show that the 10 percent was intended to provide more value for early emissions reductions?

PNM Response

Yes, that's the idea. And we could talk about a different number. It doesn't have to be 10 percent. That's what we've used for this round of results.

Western Resource Advocates continued.

I understand that approach.

NM State University: Differences Across SERVM Simulations

What differs across the 10 SERVM simulations? […] I thought the weather scenarios were the same each time, so I was asking what is varied across the 10 simulations?

PNM Response

For each hour in each weather year, SERVM does a Monte Carlo simulation, a random draw on the load, the forced outage rates of resources, and also on the production profiles from solar and wind.

Those are the things that are changing [in] each of those 10 simulations.

NM State University continued.

So, what's the deterministic part?

PNM continued.

It is not deterministic. The SERVM model is not a deterministic model. It's a stochastic model. EnCompass is a deterministic model.

NM State University continued.

Maybe I am misreading the earlier slide. I'll go take a look.

PNM continued.

When we're modeling an extreme weather case, that is a deterministic evaluation, and we're trying to [understand the difference between that and] our base [(P50 load)] case.

[The extreme weather load forecast and P50 load forecast] are two deterministic forecasts that we have in EnCompass.

What we're trying to do is get a sense of a reliable portfolio from SERVM: [what is] the range of unserved energy [produced across SERVM simulations for an extreme weather year] … and how that compares to the differential we're seeing from a deterministic point of view in EnCompass.

So, we're trying to make that leap to see if EnCompass is really going to give us a reliable portfolio or not. That's the slide [Slide 12] that is up on the screen now.

We think that the comparison is between [the extreme weather case run in EnCompass and] a single SERVM simulation, right? One of these dots versus the deterministic EnCompass case.

NM State University continued.

How do you choose which one of the SERVM you're comparing against?

PNM continued.

When we look at all these dots, we say, “Okay, a single year, a single run could result in up to 1,500 megawatt hours of unserved energy for an extreme weather year like 2011.” So, we just figured if EnCompass spits out unserved energy somewhere in this range of dots we circled here, we can't say that’s not a reliable portfolio because that one case is in the range of things that resulted from SERVM simulations for an extreme [weather year].

NM State University continued.

Okay, that makes sense. You’re saying It fell within the realm of what we think are the possibilities.

PNM continued.

Exactly, yes.

We're trying to focus on an extreme weather year here [Slide 12] and that's exactly what we're trying to do in EnCompass. What SERVM is telling us is when we look at an extreme weather year, here’s how much EUE we’re having, like in a Monte Carlo kind of stochastic view, here's the range of unserved

energy we're seeing. And [in] just one deterministic [extreme weather] case in EnCompass, the EUE is falling within that range.

And so, we think that we have a good case to say that each of these portfolios, even from the low end to the high end of EnCompass results [Slide 11], all [unserved energy that resulted from the extreme weather case falls within a reasonable range, and so we cannot say that these portfolios are producing results that lead us to believe they would be unreliable].

Recall that once we get to Phase Three, we're going to run all of these portfolios through SERVM, at least in the Current Trends & Policy case, so we'll get a much better, detailed result from that analysis when we get there.

NM State University continued.

Again, I misunderstood where you used the deterministic earlier in your slides. There might be something that would make it clear.

PNM continued.

Thank you.

Advanced Energy United: Reliability evaluation

What was the reasoning for scuttling reliability?

PNM Response

All portfolios are designed to meet a baseline Planning Reserve Margin (PRM) (calibrated to a 0.1 LOLE target); however, as we have discussed previously, PRM alone is insufficient to guarantee a reliable system. As a part of Phase 1-2 modeling, we performed a reliability check on all portfolios – see slides 10-12 of PNM modeling results update presentation. When these portfolios were evaluated under a deterministic extreme weather load case, we did not find that any portfolio had unserved energy outside the range of outcomes considered reasonable for a reliable portfolio. Further, there was not enough differentiation in this deterministic approach to justify the weighting we originally contemplated.

As a part of Phase 3, we will conduct detailed reliability modeling via SERVM. Additionally, we plan to conduct resiliency studies with the Most Cost Effective Portfolios (MCEPs) and we will give these results significant weighting when evaluating Phase 3 portfolio scores.

CSOL Power: Carbon emissions

Are carbon emissions only restricted to operations and not upstream?

PNM Response

Carbon emissions reflect those that result from the combustion of fossil fuels for electricity generation to serve PNM retail load.

Our modeling is consistent with the emissions requirements laid out in the New Mexico Energy Transition Act. This prescribes carbon intensity levels for emissions that result from electric power generation, i.e., stack emissions.

NM PRC: Fuel supply and price volatility sensitivities

IRP App A specifies fuel supply and price volatility as one of the criteria for evaluation. If PNM is to continue with the "donut" this should be added.

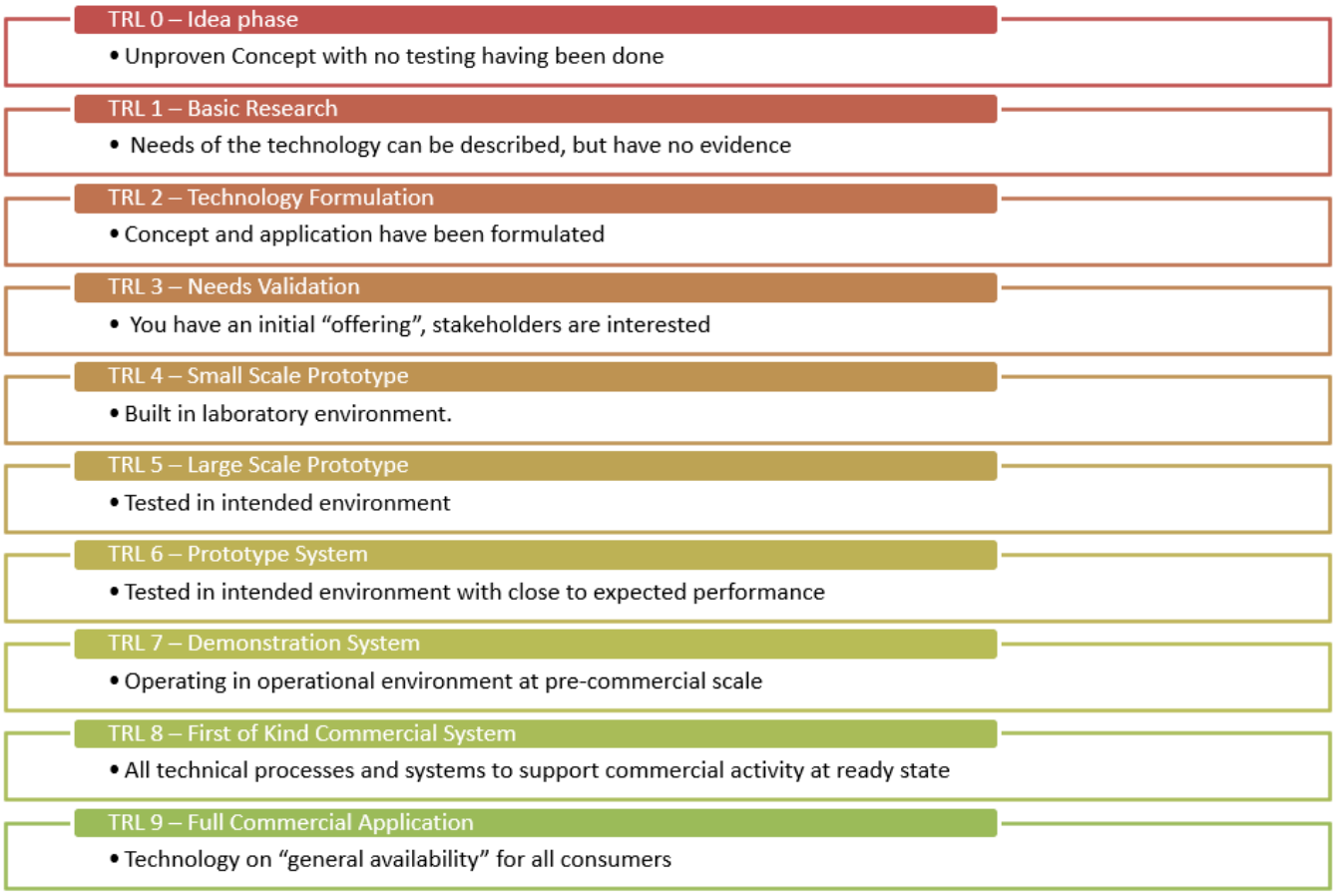
PNM Response

PNM will model a variety of sensitivities in Phase 3 scenarios, including those that incorporate high and low natural gas and market prices. Sensitivities can be found on slides 21 and 30 of PNM's modeling results update presentation.

Strategen: Technology Readiness Level scale

Do you have a TRL scale that you can share with us?

PNM Response



NM PRC: IRA incentives

I understood that the IRA provides incentives, funding, etc. for variety of technologies, hydrogen, RE, storage, DERs. Have you been able to include IRA effects on all resource types?

PNM Response

PNM has incorporated Investment Tax Credits for all storage and Carbon Capture technologies, and Production Tax Credits for renewable, nuclear, and hydrogen production.

NM RETA: Base Technologies only scenario cost

Why are base tech costs high? Compared to tech that is not considered ready?

PNM Response

The Present Value of Revenue Requirement for each portfolio (presented on slide 14) reflects the portfolio cost over the study period. The cost for the "base technologies only" portfolio is highest because it requires the greatest amount of installed capacity (due to ELCC effects and the lack of long-duration storage or new dispatchable resources in that scenario).

NM PRC: Thermal-CT scenario

Clarify the "thermal -CT" scenario. I believe that is hydrogen-ready CT, right?

PNM Response

The "Thermal – CT" scenario includes base technologies, and allows for the addition of Combustion Turbines capable of burning hydrogen in 2040 and beyond (these incur a hydrogen conversion cost in 2040). The hydrogen burned in these CTs in 2040 and beyond is assumed to be delivered to the PNM system (as opposed to being created vis electrolysis using designated renewables and stored on site, as in the Green Hydrogen scenario).

NM PRC: Hydrogen costs in Thermal-CT scenario

What hydrogen-related costs are included in the CT scenario, conversion cost, CCS, fuel cost, hydrogen transport cost.

PNM Response

In the Thermal-CT scenario, all CTs remaining online in 2040 and beyond incur a conversion cost that reflects the necessary upgrades to enable 100% hydrogen combustion. The cost of delivered hydrogen ranges $20-21/MMBtu ($2025, base assumption) in 2040-2042.

In the Green Hydrogen scenario, costs associated with hydrogen production and combustion include hydrogen-ready CTs, electrolyzers (and associated PTCs for hydrogen production), solar resources to supply the electrolyzers (and associated PTCs), and hydrogen storage (above-ground).

ICF International: Hydrogen economics

Is the Hydrogen scenario economic in the long term after the IRA credits expire?

PNM Response

All of our modeling is based on our current understanding of the IRA and assumes the hydrogen PTC expires in 2032. Based on these assumptions, we don't see much hydrogen production and combustion once the hydrogen PTC expires. While the Green Hydrogen case is the lowest cost over the study horizon (2023-2042), cost advantages are directly attributable to PTC value (including PTCs for wind and solar).

However, the extent of the IRA impact on the Green hydrogen industry remains to be seen. The PTC is incredibly valuable and is likely to spur investments in green hydrogen production that provide for technology improvements and efficiency gains and could eventually result in a hydrogen economy. These types of developments may decrease the cost of initial investments in green hydrogen on a broader scale and help future project economics, particularly in places where there is a strong renewable resource. Extension of the hydrogen PTC can be expected to incentivize hydrogen investments further into the future.

Western Resource Advocates: Hydrogen costs

To Cynthia's point on the hydrogen question, we'd like the filed IRP testimony to explain the hydrogen cost, and the assumptions for how hydrogen will be proven to be green that is underlying the cost estimate (including examples of real projects for hydrogen production).

PNM Response

The IRP is not filed with testimony, it is a report that is either accepted or sent back for revision based upon whether the IRP Statement of Need and Action Plan comply with the policies and procedures of the IRP rule (NMAC 17.7.3.9).

NM PRC: Scenarios in Phase 2 vs. Phase 3

Slide 20: what is the difference/distinction between the Phase 2 last and next to last runs w/ all LDS and LDS+CT (slide 8), and what you show here # 3 and 4? PRC Staff would like to see a BaseTech with Valencia and Reeves extension and LDS.

PNM Response

a) Phase 3 will incorporate the Base technologies + LDES and Base technologies + LDES + CT scenarios also modeled in Phase 2 – there is no difference in the technologies available for the model to optimize in these scenarios between Phase 2 and Phase 3. However, when modeled under different sensitivities in Phase 3, these scenarios might produce different portfolios/resource mixes than in the Current Trends and Policy (CT&P) case modeled in Phase 2.

b) Per Gridworks, the deadline for submitting modeling run requests was May 26.

NM PRC: Valencia/Reeves extension scenarios

Slide 24: should FC be adjusted now to reflect 2031? How does the early retirement FC effect the analysis? Q: There is no change in installed capacity between BT and V&R cases. You assumed 5-year extension on V&R? So, there might be value to a 5 year extension that is not being reflected here.

PNM Response

These scenarios were specifically requested by a stakeholder. The first assumes PNM exits its share of Four Corners in 2027, and the Valencia PPA is extended through 2039. The second assumes PNM exits its share of Four Corners in 2027, the Valencia PPA is extended through 2039, and Reeves continues to operate through 2039. In both of these requested scenarios, Valencia and Reeves extensions do not incur any costs – they are free (as agreed to by stakeholders in the modeling request meetings).

In the Base Technologies only scenario, Valencia PPA expires in 2028 and Reeves retires in 2031.

In 2040, the stakeholder requested scenarios produce the same portfolio as in the Base Technologies only scenario because Valencia and Reeves do not operate past 2039.

NM PRC: Hydrogen costs in Thermal-CT case

PRC would like the underlying cost assumptions and 20-year cost stream (capital, fixed and variable O&M, and fuel costs), and any hydrogen related costs, for the CT case. Q: does PNM have similar cost data for Valencia and Reeves?

PNM Response

All available information can be found in the data sets posted to the Venue site. Because this is not an RFP evaluation, we will not be posting project-specific information, such as for a Valencia extension.

Member of the Public: PVRR translation to bill impacts

Can we translate the highest cost to the lowest cost portfolios into the real world? What would be the difference in an average consumer's monthly electric bill?

PNM Response

The IRP rule requires evaluation of portfolio costs over a planning horizon of at least 20 years, – we have done this with the PVRR metric. Bill impacts would only look at a single year and may not adequately capture long-term tradeoffs in resource choices. Furthermore, transforming PVRR into bill impacts would require assumptions around cost of service, cost allocation, ownership structures, etc. – this is beyond the scope of the IRP.

NM PRC: Thermal-CT scenario vs. Valencia/Reeves extension scenarios

I am having difficulty understanding the thermal-CT case versus extending Valencia and Reeves. They're all just CT's burning gas except the thermal-CTs have the potential for hydrogen conversion at the end. Is this correct?

PNM Response

In the Valencia and Valencia & Reeves extension scenarios (stakeholder requests) there are no additions of thermal resources (and no hydrogen combustion) – the only new resource types available to the model are wind, solar, and 4-hr lithium-ion storage (the same as in the Base Technologies only scenario). However, one can glean from the Thermal - CT analysis whether gas fired generation is cost effective when Reeves or Valencia would come out of the portfolio. If similar amount of new gas is added at those times, one can conclude that whether new gas, or an extension of those units, is cost effective and the specific choice would come down to RFP bids in an RFP evaluation.

These two stakeholder-requested scenarios differ from the Base Technologies scenario in only two ways:

1. PNM exits its share of Four Corners in 2027 (as opposed to in 2031)
2. Either Valencia (in the Valencia extension scenario), or Valencia and Reeves (in the Valencia and Reeves extension scenario) extend through 2039 at no additional cost (as opposed to the Valencia PPA ending in 2028 and Reeves retiring in 2031)

The stakeholder requested scenarios differ from the Thermal-CT scenario in three ways:

1. PNM exits its share of Four Corners in 2027 (as opposed to in 2031)
2. Either Valencia (in the Valencia extension scenario), or Valencia and Reeves (in the Valencia and Reeves extension scenario) extend through 2039 at no additional cost (as opposed to the Valencia PPA ending in 2028 and Reeves retiring in 2031)
3. Options for new resource additions include only wind, solar, and 4-hr lithium-ion storage (as opposed to wind, solar, 4-hr lithium-ion storage, and generic Combustion Turbines that will be converted to burn hydrogen in 2040)

NM PRC: Carbon emissions scoring criteria

Is it necessary to score scenarios on carbon emissions when the NPVs are all very close and they all meet the ETA?

PNM Response

We think it’s important to consider the extent to which some portfolios can provide for earlier reduction in carbon emissions. Given that all portfolios meet ETA requirements, the NPV CO2 metric receives an

overall weight of 15% in the scoring methodology – far below the 70% weight given to portfolio cost (as measured by PVRR).

Western Resource Advocates: Survey factors use in IRP

How would the 12 factors then be used in the IRP?

PNM Response

Stakeholders were asked to submit their top five factors (IRP evaluation criteria priorities) and rank by importance. PNM has proposed using the results of the factor survey to create a stakeholder-derived scoring matrix. Ultimately, we'd like to compare Phase 1-2 results scored using PNM's scoring matrix with those scored using the stakeholder matrix. The overall goal would be to understand where PNM and stakeholders align in terms of evaluation criteria and level of importance.

NM State University: RFP resources in IRP modeling

Re: the new 2026 storage and solar contracts covered at the start of this meeting, was their pricing already factored into the pricing assumptions used as input for the IRP modeling?

PNM Response

Final modeling results will incorporate 2026 RFP resources and associated costs. The results presented on July 27th do not reflect incorporation of these resources into IRP modeling.

Ultimately, the RFP resources will be the same in all portfolios so addition of these resources is not expected to materially change the comparison across portfolios.

NM PRC: Hydrogen Costs

Additional question for follow-up modeling discussion: for green hydrogen, could we please have all cost assumptions (capital, fixed and variable O&M, fuel, water, transportation) and the 20-year cost stream?

PNM Response

All available information can be found in the data sets posted to the Venue site. Because this is not an RFP evaluation, we will not be posting project-specific information.

Western Resource Advocates: CT conversion for hydrogen combustion capability

If new CTs are assumed to use up to 30% hydrogen, depending on fuel availability assumptions, would they be restricted to a 20-year lifetime and depreciation period in the modeling? (Because a 30% H2 capable CT cannot be converted to 100% HC capability)

PNM Response

New CTs in the Thermal-CT case are assumed to burn natural gas through 2039. In 2040 they incur a conversion cost and are assumed to burn 100% hydrogen thereafter. Generic LM6000s have a 40-year operating life and depreciation period. This is appropriate because it is reasonable to assume that these resources will be able to utilize a non-carbon-emitting fuel (hydrogen or other) and operate for the entire 40-year life.

August 31, 2023
Meeting #8

Member of the Public: Geothermal Energy

I am looking at section 4F [of this Statement of Need]. Under candidate resources there's a pretty good list, but what is not there, which I think New Mexico is in a position to develop, is geothermal energy, which, I think is at least as mature as a number of others that are listed here, like hydrogen or flow batteries, iron air storage--all of those are emerging technologies. Geothermal, of course, is a very mature technology under some definitions, but New Mexico is really trying to develop that in the state, and I just would like to advocate for adding geothermal energy development to that list of candidate resources.

Initial Response: Gridworks

Yes, great comment.

Working Group continued.

I would agree with that 100 percent.

PNM continued subsequently.

We [have considered] geothermal, [in response to the question from the member of the public].

We conducted an RFI (Request for Information), and we did not get any geothermal responses. We could have used some generic information, but most of what we're using in this modeling is information that was subject to a request for information that we put to market, and we did not get any geothermal market based responses.

And so that's why you don't see geothermal here. [In some of our earlier meetings … we did discuss geothermal, and we did show some of the cost aspects and other things and discussed why we did not move it forward in the overall candidate resources. But it will be discussed.

NMPRC: Scope of Statement of Need

We agree with PNM that the Statement of Need is very narrowly defined, and it focuses on whether or not the stakeholders agree with the preferred resource plan, which PNM is still to identify, and the new resources that they would add based on the modeling results. So that's the key focus of the Statement of Need.

In terms of the other matters outside of the Statement of Need that essentially fall within the parameters of the entire IRP rule and IRP filing, anything that the stakeholders believe should be included that is not in the rule, or in the plan filed, can be part of parties' comments. Or, say, if we had started at the first meeting with teeing off the last IRP as the starting point of Statement of Need and an outline of an entire IRP, we could have gone through that and found what we agreed with or disagreed with and possible omissions in the filing or omissions in the rules.

Initial Response: Gridworks

Great. Thank you for that clarification.

PNM continued.

Just to clarify, the IRP does not procure resources and we are not seeking in the Statement of Need or Action Plan to identify specific resources for procurement. There's a separate section in the IRP Rule about procurement and RFPs, and at most what the Action Plan will do is identify that an RFP should be issued. But we will not be identifying specific procurement targets in the Statement of Need.

So, just to make sure that clarification, based on NMPRC's comment, is understood. The Statement of Need will show general trends; procurements are actually done in a separate process.

Western Resource Advocates: Scope of Statement of Need

My schedule permitting, I worked with the Statement of Need group during a few sessions and the group felt it was really important to identify the policies and preferences that should guide the selection of resources and should guide the Action Plan and not be strictly limited to the modeling results.

I realize the Statement of Need is the one that the stakeholders submit is within our control. But I guess my question is: Is there a better place if we need to, if we want to, remove some of the content of our draft Statement of Need, where should we put it instead?

PNM Response

You'll get a chance to review our IRP before it's filed. We've got two more meetings coming up. It's our intention prior to the September [2023] meeting to show you the mapping of where the different elements of the stakeholder Statement of Need--if it's not going to be included in our Statement of Need, or we don't believe it will be included in our Statement of Need--that will be included elsewhere in the IRP.

The goal would be for the October meeting to make sure that we have a near final Statement of Need as well as a pretty good draft of the IRP and Action Plan--all that together--because that's our last meeting before we file the IRP, unless there's a desire from Gridworks to schedule some other interim meetings throughout the holiday season. Stakeholders have the ability if they disagree then with what is filed.

The purpose of this process is to try to reach agreement on the Statement of Need and the Action Plan. If there isn't agreement reached, [per Section E of the IRP Rule] we will in the IRP explain all resolved and unresolved issues. So, we have to have that list in our IRP.

And then stakeholders have the ability if they disagree to include their own written comments, including their own Statement of Need or their own Action Plan. And the utility is required to have a written response to all those comments when we file our reply comments.

So, you're going to get an opportunity throughout the rest of this facilitated process to see where we are going with things to review the IRP itself. And if you feel like it hasn't gone far enough in the way you were considering, Western Resource Advocates can file its own statement and Action Plan and other comments.

NMPRC: Scope of the Statement of Need

I really appreciate the comments about other elements that are important in the Statement of Need that go beyond just saying the preferred resource plan and the new resources.

My comment about expediency: We believe that we could have cut to the chase sooner if, for instance, a Statement of Need working group had sat down with the IRP Rule and worked off of that to identify any gaps or omissions in the IRP Rule beyond the specifications just mentioned on Statement of Need.

Gridworks Response.

Thank you.

Member of the Public: Scope of the Statement of Need

I've been really involved with this process, as many know, and I think that that section in the Statement of Need … that lists out these various modalities of power delivery is a section then I had always envisioned would be in some kind of a table, much reduced and not necessarily in the Statement of Need, but a way for outside people like Statement of Need committee members, the whole team, and the whole external group, to be able to understand the comparison of those items that into the modeling,

those that didn't, and why. I don't see them as part of the Statement of Need necessarily.

I also want to speak to something else because I am well aware PNM will have to respond to anything that we put in a Statement of Need. I think that there's an obligation also to make sure that those things

are framed in a way that they can be understood and responded to in some effective way, and, in addition, identify those things that are beyond the scope of the IRP or a Statement of Need, so that we really can keep those things out of the current conversation for future IRPs.

In that regard, something that was not shown today is that attached to the current draft of the Statement of Need is something that we've called the list of other issues, or the parking lot. We've simply put materials to be followed in the future.

In my own view, those are materials that don't have to really be engaged with the IRP, but they should also not be forgotten.

Initial Response: Gridworks

Thank you for bringing that up. In the posted document that is included. We didn't show it on the screen today, but other considerations were part of the original document.

PNM continued.

I forgot to mention this, but we certainly do want to have, and we will have a very robust section in the IRP and the appendix discussing not just a facilitated process, but the entire Public Advisory Process, going back to April 2022. We will also include recommendations of ideas for future work or future discussion from the stakeholders, as well as PNM, as one of the items that we'll discuss in the IRP itself.

So, I did want to mention that we didn't want to focus on just the Statement of Need and the IRP itself. I know that the stakeholders put a large list together of other things that should be considered going forward and we don't want to lose sight of that. And that's an important

discussion for not just what did we do in this IRP but what is our roadmap going forward for potential areas of future work, future study.

We'll have to prioritize it, of course.

That gets to what Gridworks had said are some of their recommendation--may be starting this process much, much earlier, both in terms of modeling, and maybe some other thoughts to try to make sure

that we're not trying to do all this at six, seven, or eight months when it really does take about two years to put an IRP together from when we start doing all the data gathering. If you want to talk about R&D work on modeling techniques, it's a full three-year cycle from when we start doing R&D work, gathering data, putting together everything before we file.

So, it's a very long process that we do here internally and if the desire is to make sure that there is more stakeholder involvement throughout the entire process, then the process has to be understood that it is a two-to-three-year process to put together an IRP, including all of these ideas.

Gridworks continued.

From our observation of the working group and its needs, they needed to be expansive to think about the whole IRP and then it gets more collapsed down to the energy and capacity portion. That kind of goes to what's in the [IRP] Rule.

And so, I think for those that weren't involved in the Statement of Need process, it may look like, well, 'Why was all this put on paper?' But I think the thinking process for the stakeholders was to think expansively about all the things that need to be considered in the future, and as mentioned, the policies that are guiding where we're going. It was important to capture it all in a document and then think through what should be considered in the future.

So, we're kind of wandering around, and we think that we'll get to a good place. We appreciate the time of the stakeholders to be engaged and be thinking holistically about how do you screen and think about all the potential risks, futures, opportunities going forward.

New Mexico State University: Resources for Period of Action Plan

Are the new resources for 2026 to 2028 already built into the modeling assumptions presented [on Slide 3]? To what degree is 2025 to 2027 already baked in versus is there some flexibility in the Action Plan that will be developed?

Initial Response: PNM

So, the RFP that we currently have outstanding spans resources that could deliver in 2026, 2027, or 2028. At the July meeting, I gave an update on where we are with the evaluation for resources in 2026. And the resources that we are currently contracting for we have included in the IRP modeling currently, but that case has not yet been filed with the Commission and the approval of those resources is subject to the Commission's review. So, while we are using that is our best assumption as we know here today, it is still not a certainty.

We have not completed our evaluation for resources in 2027 or 2028 out of that RFP, so all the information included in the IRP right now is based off of the generic placeholders.

But in terms of the Action Plan period, there really is not enough wiggle room given the timing it takes to evaluate an RFP and bring resources online to have things in the Action Plan that would somehow override what we would be doing in the 2027 and 2028 RFP evaluation.

The likely outcome will need to be that we will have to take a new RFP to market after we file this IRP for resources that would deliver in 2029 and beyond, depending on what the time frame and the ultimate Action Plan says. But there's just not enough time to do a new RFP or alter the existing RFPs for resources in 2028 and earlier.

Gridworks continued.

Does that address your question?

New Mexico State University continued.

Halfway. So, you haven't baked those assumptions into the models yet even though you can't change the RFP. The models are still sort of open and choosing the best thing? So that's what I'm confused about.

PNM continued.

So, the 2026 resources and those specific resource types and sizes are already explicitly put into the IRP model. We have not finished our 2027 or 2028 RFP evaluation. So, we have not put in specific resources

that result from that evaluation into the IRP model yet. We're letting the IRP model fill out with generic resources available in that timeframe.

We do not have time to restart the RFP or issue a new RFP and still actually get resources online in time for 2027 and 2028. So, while we're using generic placeholders, the actual resources that will be put into a Commission-filed docket for approval will be coming from that RFP that is already active, and not from a new RFP.

I hope that that clarifies.

New Mexico State University continued

Yes, excellent. That's a good answer. I hope that can be clearly explained in the RFP text itself. Thanks.

Pine Gate Renewables: Green House Gas Emissions

Why doesn't the base technology case have the lowest greenhouse gas emissions, given none of those technologies listed emit?

Initial Response: PNM

In the base technologies case, the new resource options are limited to wind, solar, and storage, but it does still include our existing thermal fleet. So, it's got carbon emissions associated with the existing thermal fleet and all of the carbon emitting resources that are still operational in 2039 that then retire and stop running in 2040 and beyond. But the base technology only really refers to the types of new resources that we allow the model to choose from.

So, a good way to think about it is, is depending on what new resources are added, certain new resources will have greater effects on the way the existing resources are operated than other new resources.[Noting our earlier] point about wind, it has extremely high capacity factors overnight and in the non-summer months, and so it can actually replace certain energies coming from combined cycle units that will be running overnight instead, and causes a decrease in the carbon emissions from the

existing fleet, whereas just solar and storage would have less of an effect, especially short duration storage.

Similarly, if you were to add carbon capture, such as Afton CCS, that is a way to abate carbon from an existing combined cycle unit and would cause carbon and reductions that would not be available to the base technologies case because carbon capture was not in available technology.

So, the only the only cases that have lower carbon than base technologies are those cases that have CCS, or the wind expansion, which allows wind to come online earlier than in the base technologies cases.

Gridworks continued.

Does that address your question?

Pine Gate Renewables continued.

That answered the question. Thank you very much.

Member of the Public: Economy-Wide Electrification

Is there a future's model that assesses all uses of fossil fuels convert to clean electricity: For example, all electric vehicles with no gas and heat pumps replacing all gas furnaces and boilers? So, an all-out electrification scenario future.

Initial Response: PNM

We do not have that future. The National Carbon Policy future assumes that we've got to be totally carbon free by 2035. There are some other assumptions like accelerated adoption of EVs [electric vehicles] and more behind the meter solar, but there is no future that encompasses sort of an economy-

wide electrification, zero carbon outcome. So, I would say the National Carbon Policy is maybe the closest thing we have to that.

We also have sensitivities where we'll look at increased electric vehicle adoption on its own, or a high rate of behind the meter solar adoption in isolation. We can look at bits and pieces of something that might go into a reality like that, but the answer is, no, we don't have an all-encompassing electric economy-wide electrification future.

I think the key there is also we need to take a look at what the current policies on the landscape for New Mexico, or the U.S. overall, are as well as the timeframe for those. There's currently no known timeframe that would require any economy-wide decarbonization within our planning study period.

We are taking a look at some things that would accelerate certain targets, but PNM is beyond the control of mandating customers switch to all electric heating or mandating all electric vehicles from this point forward.

So, we're working with the best available information we have that could affect our system and how we respond to it, not suggesting that we have the magic ball to create an economy-wide decarbonization.

Gridworks continued.

Does that answer your question?

Member of the Public continued.

It does. It's not the answer I was looking for.

I am going to put in the chat a peer reviewed scientific paper that does that analysis for all U. S. states, including New Mexico. I encourage you to go look at that. That will be in shortly. Thank you.

PNM continued.

We can definitely take that into consideration for future IRPs.

NMPRC: Long Duration Energy Storage

For the long duration energy storage cases, the amount of short duration storage is still very large relative to long duration. Why doesn't the model choose more long duration?

Initial Response: PNM

The model does a cost minimization optimization based on all the inputs that we have for storage. So, on the relative cost of storage, relative efficiency, the long duration storage technologies tend, while they have more energy capability, to be a bit lower efficiency than the battery storage.

There are just a lot of things that the model is optimizing against.

It's a tradeoff between the various factors—cost, reliability, emissions, all of those things--and it's coming up with what the model believes is the most representative mix of a best portfolio.

It's very intuitive as well, because if we think we're going to need some short duration storage on the system, no matter what the scenario--because we're going to use that short duration storage for intra hour and day to day operations--we're going to want to have some longer duration stuff that's going to help us with ensuring that we've got enough energy

that, on a Monday when it’s super sunny, to use on a Thursday when it's cloudy.

And then we're going to want to have seasonal build up over time when we can capture excess renewables in the spring and use it in the summer and the same thing in the fall and use it in the winter. So, there are different use cases for different durations of storage.

NMPRC continued.

My takeaway is that the cost and reliability and efficiency of long duration is still emerging. It's probably more expensive and less efficient still than short duration.

PNM continued.

I think the key to think about is that all of the different resources have different costs, different efficiencies, and other attributes. So, just like in a traditional system, the optimal mix was never 100% coal or 100% gas or 100% nuclear. But it was a mixture of them because you had different costs tradeoffs, resources are added at different points in time. You wanted to have fuel diversity and they would provide these, these various balances, throughout the system.

The same is true for different types of energy storage. You don't have a one-size-fits-all solution, nor do you want a one-size-fits-all solution. There are all of these different **tradeoffs,** and you want to have diversity in types of resources and locations and durations and efficiencies--all of these things to make sure that you are capturing each of those attributes and able to best optimize the operations of your system with those.

Western Resources Advocates: TRL of Combustion Turbines [CTs]

What is the TRL of converting CTs to hydrogen?

Initial Response: PNM

We've assumed that CTs have a TRL [Technology Readiness Level] of 9. And the reason that we asse that is because we know that it is highly likely that they will be able to burn an alternative fuel come 2040, whether that's hydrogen or renewable natural gas, or some other type of non-carbon emitting fuel.

It's really CTs that we will convert to a non-carbon emitting fuel. It doesn't have to be hydrogen.

We've assumed hydrogen as kind of a higher cost version to be conservative because while there are turbines today that can burn 100 hydrogen--for example, B class GE series turbines—the turbines that we're modeling right now as aero derivatives would require changing out of certain … infrastructure--blades, fuel, injectors--in order to burn hydrogen. There are scenarios where you would have a non-carbon emitting fuel that wouldn't require that, that would be less costly than what we're assuming here for the hydrogen conversion. And then the hydrogen fuel costs itself.

Also, there is the timeframe. CTs are a known proven technology. They're not converted to burn hydrogen at 100% level until 2040. There's more time to allow the effects of the IRA [Inflation Reduction Act] to allow a more fully mature hydrogen economy and produce the necessary equipment for hydrogen.

But there's always the fallback of renewable natural gas or captured methane or other such things. So, there are a number of things that we're considering, and why we would use a TRL level of 9 here; where for the green hydrogen scenario, as a tradeoff, we were using a TRL of 5.

Gridworks continued.

Does that answer your question?

Western Resource Advocates continued.

That answers my question.

Western Resources Advocates: Green Hydrogen

I've asked this question before. I know green hydrogen didn't make it into your Phase 3 modeling, so it may not be as much of an issue anymore, the green hydrogen case. I understand what you said about green hydrogen, the 256 megawatts of CTs being only a small percentage of the portfolio, but it seems like a critical percentage of the portfolio. That's why I question weighting it with firm capacity versus almost like a weakest link methodology.

I was just wondering where your thoughts are on that because that still seems pretty high with that 256 component, even though it's not a big component of the portfolio, it's sort of critical. So, without it, the portfolio doesn't work.

Initial Response: PNM

We stuck with firm capacity. So, it does make up a larger proportion, 256 out of the name plate, as a smaller proportion … and it's called 256 firm out of the total firm capacity.

So, we've used firm, capturing a bit of what you're saying, and I hear that may be it makes sense to think about how critical it is. We think that firm kind of captures the nature of critical.

The firm is relative to the amount of perfect megawatts that we need and we get out of those resources. So, when we talk about the criticality, each one of those firm megawatts is equivalent to each of the other firm megawatts in the value they provide. The difference is how we want to rely upon those from a TRL perspective.

So, we probably misspoke earlier. The total amount of firm capacity out in 2040 is somewhere around on the order, on a current trends and policy basis, of 25 to 3000 megawatts. It's got our peak load plus the reserve margin of firm capacity, so it's really like 256 out of 2600 or so megawatts.

Western Resource Advocates continued.

A percentage.

PNM continued.

Yes, so using firm does create a larger weight for that newer technology. But even so, 10% is not nothing but it's not everything either.

Western Resource Advocates continued.

Yes. I was just thinking--it might not matter as much anymore--but if you lose that 10%, if that .5 turns out to be 0 because it's not available, that portfolio doesn't work.

So, I was just thinking that the weight should be more than it's component of firm capacity.

PNM continued.

I would caution to say that it doesn't work because we will certainly have more than 10% of reserves. It certainly depletes the amount of reserves, but the system is designed in a way that it can operate with a loss of 10% of the resources.

Western Resource Advocates continued.

Ten percent of firm resources, though.

PNM continued.

Yes, it could operate with a loss of 10%. So, the LOLE studies and the PRM calibration get the firm megawatts, and so if we're using 16, 17, 18% reserve margin, that's on a firm capacity basis. Even if we were to lose 10%, we're still going to have 6,7,8% left if everything else is still not an outage.

And that's how we look at designing the system. We know that that amount of reserves is going to have to grow over time. And we would certainly take into account the technology readiness when looking at setting a reserve margin or LOLE characteristics going forward. But based on where we're sitting here today, even the loss of a resource that would make up 10% of our system would not put us below what our load survey capability needs to be.

Western Resource Advocates continued.

Thank you.

Member of the Public: Landfill and Methane Gases

I would just comment that exploring the availability of landfill gas or methane gas as a replacement fuel really just means that you're ignoring the better option of mitigating those emissions at the source and saying that busting those methane emissions and generating carbon dioxide emissions instead of methane emissions is a preferred option. The best thing is to just stop them at the source and cease all combustion that would create CO2.

So, I am not in favor of that particular option.

Gridworks Response.

Thanks. Appreciate that.

Member of the Public: Public Information on Transition from Non-Fossil Fuels

[Regarding the reference by Gridworks of my advocacy of public education surrounding energy issues], I would prefer if the word we're not education, but information because I think the public needs to be informed about these things, and I don't want it to be devolved into an education process. It may be kind of a fine hair distinction, but I think it's very important that PNM and also various outside parties who have much more technical knowledge than the general public find avenues to get reliable and trustworthy resources that can inform the public about how the transition from fossil fuels to our non-fossil fuel energy generation occurs.

It is my fear that the community can't weigh in in very thoughtful ways if it doesn't have more reliable information --repeated [more] often than just happy sound bites or unhappy sound bites that come from unknown places.

And I really like to have other people weigh in on this concern because I don't think I'm alone in it.

Gridworks Response

Great. Do you have some thoughts about how to measure the effectiveness of such an information system, or do others have thoughts about that?

Member of the Public continued.

Not at the moment, but that doesn't mean I can’t come up with something in the future.

New Mexico State University: Scope of the Action Plan

My question is about the scope of the Action Plan; I'm thinking of three distinct categories. One is, given the information that has that has come out with models, there are various directions that you can proceed based on that information.

The second category is how can the modeling process, and the information gathering process for the IRP, be improved in the next cycle?

And then the third one is more like the PRC's process, an example of which you just commented on, is that we're in this awkward state where that first part of the Action Plan has already been baked in and decided. (That was my earlier question.) So, what do you put in there for the next three years, if you've already figured out what you're doing? That's more like laws and rules with the PRC [Public Regulation Commission]?

Are these categories all fair game for the Action Plan?

Initial Response: Gridworks

They're all fair game for collecting at this point. They are fair game for submitting and for us documenting in the Gridworks report that we do. The items that are required to be responded to by the utility are going to be related to the first category that you describe.

I like the way you parse them. The first, the modeling insights results from the modeling and the resulting capacity additions, those are the ones that relate meeting the Statement of Need as defined by the Rule and are things that the utility will be required to respond to. The other two categories--process improvements for the next cycle, or

just overall PRC kind of changes in the requirements for this process--are also things that we can document that are not required to be responded to by the utility.

Is that helpful?

New Mexico State University continued.

Yes. And you identified a report that Gridworks plans to submit to the PRC. So, I think it would be wonderful if this stakeholders group could work with you on that and have an explicit review of those inputs.

Gridworks continued.

Yes, absolutely. Our deliverable to the PRC under this process is a report on best practices or things that which should be considered to be done differently in this process going forward. And so we'd be happy to take stakeholder input in that. That is part of the process for our very last meeting that's scheduled in December after the IRP is submitted. We're going to have a meeting to collect some of your thoughts from the stakeholders, and we can also entertain the idea of review and conversation about that draft report as we put it together--I think that's going to be in the January timeframe.

Thank you for offering that.

Member of the Public: Stakeholder Representation

Exactly [regarding this category of representation of climate justice, energy justice, or energy equity], we talk about stakeholders, [but] it seems like there are many different kinds of stakeholders who somehow bring themselves to this table or not. And I'm wondering if there are groups that are identified either by PNM, or by the PRC, or by the PRC with the assistance of Gridworks that are categories of people that you'd like to see at the table and that we have some way of monitoring whether those groups actually make it into this conversation.

And I would think that a tighter monitoring of who we stakeholders are, so to speak, could be helpful in knowing what kind of inputs are or not are being received through this process.

Gridworks Response

I greatly appreciate that comment. That is part of our analysis that Gridworks will do for the Commission on what kind of groups participated in this process, where we reached out and were unsuccessful in having participants of important groups. We will say something about that as well because we tried very hard, as many of you know, at the beginning of these meetings to offer input as to who else needed to be at the table.

We did quite a bit of reaching out and we were going to do another round of that as we complete this process.

So, I think your suggestion is really a good one. And any thoughts people have about ways to do that would be great. We will also give some serious thought to that in particular as it relates to disadvantage communities and others that we really want to be part of these conversations.

New Mexico State University: Emerging Technologies

I really want to talk about emerging technologies because I do think that

more than past IRPs this IRP really dove into emerging technologies. I

think that's largely because the options for carbon free right now seem very limited.

And it's really important to do more than just monitoring. What I had in mind is to try to further partnerships with DOE [Department of Energy] and with manufacturers or providers, and developers of new technology, to do proofs of concept, trials, ways of collecting data that would be most relevant for PNM modeling.

So, building up those kinds of partnerships to get to decision points where these technologies that are lower than a TRL of 9 could actually be deployed in New Mexico.

I don't think we can just sit around and wait for the best bid to come in. I think there has to be active participation to move these new technologies along.

Initial Response: Gridworks

Great. I'm glad to be very, very open to your submitting that as a suggestion. I think that would be seconded by a couple other stakeholders who aren't here today that suggested similar kinds of efforts. So please offer that as a suggestion. I think that's a good idea.

PNM continued.

I believe we heard others comment during some prior meetings on the creation of some pilot programs to test certain technologies. And if that's really the direction you were thinking, maybe the way we word it is 'PNM to file with the Commission for approval of a pilot program for examination of new technologies on PNM's system' because those things are not without cost, right?

New Mexico State University continued.

Yes, that's the tricky part. But right now, there is probably a lot of DOE federal money available to do things that won't cost greatly, so I think you have both options.

September 28, 2023
Meeting #9

Western Resource Advocates: Resource Types for EV and Building Electrification

Are the numbers on the chart gigawatts by resource type?

PNM Response

Yes, that's correct. And they're rounded to whole gigawatts. You'll be able to download all of the detailed information from the Venue website. You can [consider them] gigawatt by resource type or by technology type.

NM RETA: Daytime Solar

Is PNM planning to develop EV programs and tariffs to encourage more daytime load that uses solar to avoid solar curtailment and to avoid reliance on nighttime fossil fuel resources? More people are working at home and could use charging during daytime.

PNM Response

So those are some questions that also got brought up during our rate case. We do understand that over time we are going to need to develop more different types of tariffs and those are on the table.

Those do not exist today for residentials. Those are a part of our time-of-day pilot for a small commercial.

There are a number of things that we'll need, all of which are currently being looked at. There are a number of different things that would need to be put in place in order to do those correctly. Some of it is going to be a full rollout of AMI. Others will need to be changes to the overall billing system, especially if we want to go to a real time pricing rate or something that allows for more dynamic type pricing

We will continue to look at this and push those forward as we can, but the accelerated viewpoints that folks would like to see have to be balanced against the realistic expectation of how long it takes to roll out changes through metering equipment, billing equipment, and other necessary technologies needed to facilitate those types of rates and tariffs.

SWEEP: Demand Response (DR)

Are you able to see what month and hour of the year the new DR is being called?

PNM Response

When we run the simulations, they are all run in an hourly form. We did not go through and examine that for the purpose of putting this presentation material together.

In running this through an economic model, as opposed to a reliability model, this will be called on the basis of economics and also garner some production cost savings. That does not necessarily correspond with the specific hours you would think for reliability, mainly because, when we're looking at the way different tools work, when you're utilizing a capacity expansion tool such as EnCompass, the reserve margin requirement is a proxy for reliability. We still need to run it through our loss of load probability model.

So, what this is utilizing is the ELCC for demand response and allowing that to be counted towards the planning reserve margin requirement and that is the pseudo for reliability. And then it will just get dispatched as needed, for economic reasons, throughout the course of the year.

That's different than how we will actually operate it. We only call our demand response resources when we really think that we would want to utilize those for reliability reasons. It's less about economics because we don't want to see a complete fall off of our program.

If we called our programs every single day, we'd see attrition rates that would be astronomical, and would lose participation in the DR programs.

Member of the Public: Community Solar

How will the new community solar projects impact PNM's operations and system reliability? This seems to all be backed up by the grid. Is this something for the 2026 IRP?

PNM Response

Community solar is just modeled as any other standalone solar. It's on the utility side of the grid. It doesn't provide any reliability whatsoever, basically, because it's not paired with storage.

And, yes, anybody who's utilizing community solar is still leaning on the grid whenever the sun's not shining.

Western Resource Advocates: RFPs

Will you do the RFP solicitation and compare bids of different resource types, or will you actually be doing a solar RFP or a battery RFP, for example?

From what I've seen, typically, this type of generic modeling would produce a rough Statement of Need in some form where it's really like a preferred portfolio using these generic assumptions. And this generic preferred portfolio is constructed through this hypothetical modeling process that you're doing.

And then the RFP solicitations are then opened. You might indicate to bidders that your initial generic modeling demonstrated interest in this type of a portfolio and in that kind of Statement of Need resources, but it may be too restrictive to simply say, therefore, we need X megawatts of wind, and X megawatts of solar, and X megawatts of batteries. It may be better to just see what the bid prices are because the modeling doesn't include actual market prices that will be available when you open the solicitation.

PNM Response

Thanks for the question.

PNM intends to probably do, or propose to do, a couple of different types of RFPs. One would be an all-source RFP for more proven technologies that don't have the lead development times We'd probably do a more targeted RFP that would look for resources that do require that additional development time, or perhaps, say, for wind, that requires the development of an additional transmission line, and perhaps do something a bit more targeted there--due to the amount of time it would take that some of the other types of resources would not.

We will want to hear everybody's feedback as we get into the Action Plan discussion, but I do not think it would be appropriate to restrict solicitations and market analysis to just what comes out of the IRP because we probably would be shortchanging our customers the economic value that could be provided through a more broad competitive solicitation.

NMPRC: Details of Resource Types in the Statement of Need

Thank you very much [for calling on us for comment].

No, the staff does not have comments at this point. I appreciate very much the way PNM has presented the potential range in the three time periods and then also by the six resource types. But this is very generalized at this time for us, and we need to look at the output results in more detail before we can give comments for whether or not we support this in terms for the Statement of Need.

PNM Response

We will not be referencing wind, solar, or those six technology types in the Statement of Need. It's not our proposal.

It's our proposal to reference the three buckets of low cost, carbon-free energy resources, dynamic balancing resources, and firm dispatchable sources, recognizing that there are different types of technologies that fit into those buckets.

So, just to be clear, that's how we envision utilizing the bucketing approach for Statement of Need, and then breaking it down by the timeframes.

Stakeholder: New Capacity

How much of the new capacity has already been contracted or is under bid?

Do you see any issues contracting for the remaining capacity [through 2028]?

PNM Response

As far as the new capacity that would be added during the Action Plan period, not all of it is under contract, but the RFPs that will be used for those solicitations have already been issued and have closed. We are currently evaluating those RFPs.

We should be filing very soon, in the next 30 days or so, the application for the predominantly storage and a little bit of solar resources … that would deliver by 2026, and we are currently undergoing our 2027 RFP evaluation.

So, while not all of that is under contract, the RFPs that will be utilized for those resources have already been issued, closed, and are being evaluated.

New Mexico State University: Combustion Turbines (CTs)

[Regarding CTs, there is a non-zero quantity of CTs in each of the three timeframes.]

PNM Response

My concern about adding CTs is that their use as a carbon-free relies on a high degree of uncertainty, so they are likely to be stranded in 2045. That's too early of an assumption to be made because assuming

stranded cost is an assumption about what the Commission may use for depreciation rates of what other technologies are available, the likelihood of conversions.

And just as much as someone might hypothetically say that while a CT could be stranded, if you were to invest money in some other type of new technology, that doesn't end up providing the value, but we try to go with something that's less tried and true, you have the similar risk of having stranded cost or, if it's not stranded, you're not getting the value that you would hope for out of those types of assets.

So, we do recognize that, as we move through a carbon-free transition, there is inherent risk in terms of how you decarbonize. I don't think anybody today [could] say we know exactly how it's going to look in 2040. What we're trying to do is balance those risks.

And if stranded costs is one of the biggest risks out there, there are many different mechanisms that can be used to balance that stranded cost risk.

One other comment. [This refers to] depreciation rates.

Whether you have, say, a 20-year or a 40-year depreciation rate, the net present value of that investment, assuming the same rate used for amortization of cost as well as discounting of those costs and a net present value calculation leads to the exact same net present value, other than the effect of marginal income taxes.

So, when we're talking about investment decisions, whether you assume a 20-year or 40-year depreciation rate, it's not as influential as one might think.

New Mexico State University: Bilateral Procurement

What is bilateral procurement?

PNM Response

A bilateral procurement, as opposed to releasing a request for proposals to the market and competitively assessing all of the bids against each other, would be a one-on-one negotiation with a set counterparty outside of a competitive process.

PNM will not entertain a bilateral procurement because that is not in the best interest of our customers.

Member of the Public: Public Information on Time-of-day Shift

For time-of-day shift, I urge much more public discussion of this issue long before PNM expects to incentivize with time-of-day rates.

Gridworks Response

We invite others who may have suggestions about how to make this a tangible action item to please get in touch with us or with the stakeholder who raised the issue.

They have been a very consistent and effective voice in calling out the need for this. We just haven't yet come up with a language for making it tangible and measured against compliance metrics.

So. we're welcoming help on that.

PNM Presentation October 6, 2023

NMPRC: Cumulative New Capacity

Regarding PNM's presentation on September 28, 2023, what is the relationship of the potential range of cumulative new capacity by 2028, 2030, and 2040--the relationship of the bubble graphs [Slides 22-24] to the 2040 installed capacity across scenarios [Slide 26 from a prior meeting]? Where did PNM derive the data for the bubble graphs?

Initial Response: PNM

All of that information is derived from the modeling outputs that are posted on Venue. You would need to be a bit more specific.

If you were to go to the data on Venue and compare how we grouped the resource types. For example, we said, low cost, carbon free resources are going to be wind, solar, energy efficiency. So, you would have to total up the amount of incremental builds of those resource types on the different scenarios. And then for those specific time periods, those would then equate to what was on the bubble charts.

When you get to the end of the period in 2040--the bubble charts that we showed were kind of cumulative across time. So, you saw what the cumulative builds were between 2023 and 2027 and then you saw cumulatively what came on, including those periods from 2028 to 2033, and then you saw cumulatively what came on from 2034 to 2042.

If you added those pieces up to 2040, those would be what appeared in the 2040 installed capacity if you compared the corresponding scenario. So, if you're talking about, for example, just base technologies, only scenario 1, you'd need to compare the scenario 1 outputs from those time periods, building up. And then in 2040, that would match what was in the slide for total installed capacity, recognizing that total installed capacity is not just incremental builds; that is the entire capacity of system, including what is currently on, plus what has to be added over the planning horizon.

Gridworks continued.

Would it make sense to share one of the bubble charts from the September 28 meeting [so that everyone, including new participants, can see the logic of the bubble chart range]? [Your team described] a range of bubble locations, depending on what you assume as the contribution from various technologies.

PNM continued.

So, this is new installed capacity, basically through the Action Plan period. So, [it is the] potential range of new capacity by 2028. So, you can consider that either as of January 2028 or December31, 2027--up through the end of the Action Plan period. This is for the CTP or current trends in policy.

So, in that four-year period, under our current trends and policy future, we saw, depending on what scenario was, up to 1000 megawatts of new solar being added. No wind, some demand side resources, a fair amount of battery that ranged a little bit across scenarios, no long duration storage, and a little bit of natural gas, depending on which scenario we would be looking at--there were some scenarios that allowed new natural gas and some that did not.

And so, the ranges [on the slide] represent more the current trends in policy future. There were five different scenarios that we looked at. The ranges represent cumulatively new capacity. This does not assume any of the existing system. These are all new additions, including those that have been approved but have not come online yet, between today and the end of 2027.

Then, by 2032, this builds on top of the last slide. This is not just incremental from the last slide. This is incremental from 2023, including the new things that are going to come online that were approved but not online yet, the other builds that were also included on the last slide, and then what in addition.

So, from the 2028 to 2032 timeframe, across those scenarios, there's now a range of additional solar that would come on. Some scenarios do see some wind come on, some do not. There's more DSM. There's another range of battery. We see some ranges of long storage, and still a small range of natural gas.

And then it’s the same context as we get through the 2040 timeframe. It we just see as we move into 2040, then from 2033 through 2040, the variation across scenario starts to get much bigger because now we're hitting that zero-carbon target by 2040, and you start to see the tradeoffs of the different technology types that could help get you there as well as the amount of additional wind and solar that we need to meet the renewable portfolio standard of 80% by 2040.

So, that's how you would think about these. But the key here is also that this is just incremental builds from our existing system, as it sits here today.

Whereas when you go to the 2040 total installed capacity for a particular scenario, as referenced in the question, that would include incremental builds plus what is already a part of our existing system that is not removed from service by the time we get to 2040.

And all that information is found in those modeling output files that are posted on Venue.

I'll [also] point out--just to try to translate this to the Statement of Need—we are not proposing to call out solar, wind, demand side management, battery, long duration storage, natural gas, explicitly. What we would propose to do is say, “We need to get somewhere--if we total these then up between a range of 2000 to 3000 megawatts minimum of low-cost carbon free energy resources that could be comprised of these different types,” as the way we would think about it through 2040.

For a Statement of Need, we wouldn't want to be so prescriptive to say that it has to be a combination of solar, wind, and DSM in these amounts, because we don't have market bid data that we could transact on. We want to make sure that we're always going to do the best combination of resources from an RFP, from a competitive solicitation, and not pre-subscribe what the exact amount of any existing resource type would be.

NMPRC: Installed Capacity Across Scenarios

[Following up on the August 31, 2023] meeting, are there changes to the 2040 installed capacity across scenarios [Slide 26]. If so, please explain.

PNM Response

At this point in time, there are not. Now we will continue to refine everything. And so there might be small changes to the numbers. But nothing that I would say is going to be substantive.

For example, these are some of the numbers that just came out of the EnCompass model. But further on in this presentation, we noted that if we want to normalize for LOLE, and so if a portfolio was too far away from that point 1 LOLE target, we'll make adjustments to it to reflect that we could add or subtract capacity to make sure that when we compare net present value of revenue requirements, it's done on an equal LOLE basis.

And again, all of this information is on Venue. If you go to the data on Venue from the meeting on September 28, all that can be totaled up for 2040 and you can compare to see if there's any minor differences. So, all of the information is there--100 percent transparent.

NMPRC: Plans for RFPs

Could please further explain PNM's plans for the RFP to be two solicitations: all source and targeted? This is an Action Plan question.

Initial Response: PNM

Well, ultimately, that comes out of what gets filed in the IRP as the most cost-effective portfolio. Given what we're seeing on the trends right now, our current thought would be to issue an all source RFP for resources that could deliver between 2029 and 2031, recognizing that the way the procurement portion of this rule works--and I'll caveat that that is still under review from the Supreme Court, so that could change.

But the way that rule is currently written, once we file the IRP, then there's the 120-day comment period for acceptance from the Commission [Public Regulation Commission].

Once it's accepted, if we do then intend to issue an RFP, we would need to file the RFP or RFPs that we intend to issue with the Commission and the IRP docket. There will be a comment period on the instructions to bidders. Once we go through that comment period, then we can actually issue the RFP to the street.

Now, there are some complications, of course, if the IRP does not get accepted, because then we're supposed to wait to do anything until we revise it and get acceptance. And some of that can interplay with the timeframe that it would actually take to issue an RFP, receive the results, evaluate it, and get a case filed.

So, there's a little bit of interesting dynamics between how long the process to evaluate an RFP and get a resource approval, [what] construction is versus the Action Plan period, and some of those things that are kind of a side note.

But [regarding] the RFPs themselves, what we were envisioning, based on what we put in the presentation last time, was two RFPs: one that would be targeting any resource that could deliver between 2029 and 2031. That would be an all source RFP.

In our recent all source RFPs, the responses have still mainly been lithium-ion storage, solar, perhaps wind, and some natural gas options, then some demand response options, but there hasn't been much in the way of those new and emerging technologies, longer duration assets that take more time, for example, like pumped hydro that might take eight to 10 years of development time.

So, the other thought would be what we're seeing right now, if we went back to the Statement of Need slides, there was a strong need from the modeling, showing that long duration storage would help in that 2028 to 2033 timeframe.

So, a second RFP could be issued that would be specific to longer duration storage and/or long lead time technologies that would not be able to deliver in 2029 to 2031 but would need to start development activities sooner in order to deliver, say, between 2031 and 2035.

So, that would be the distinction between the two RFPs, as well as going and doing some additional engineering work. For example, do we need to build? And we know the answer is yes. But if we want to get more wind, do we need to start doing some permitting work on a transmission line in order to have the delivery system in place if we want to access new wind out of these?

So, that's kind of the distinguishing factor I would say between the thoughts on the two RFPs: one of them all source, near term, likely going to have the common technologies; another one being a little bit thoughtful, more forward looking and specifically seeking some of those things that are either those not quite mature enough technologies, or require significant development time in order to get them to deliver in the 2028 to 2033/2035 time period.

Gridworks added subsequently.

The RFP documents will go through a separate process and will be available for public comment as part of the IRP RFP follow-up. Take a look at the IRP Rule and see the sequence of steps, but that is separate from the IRP.

SWEEP: Demand Side Resources

I have one additional comment for PNM on the Statement of Need. I've made similar requests [previously]. I would like PNM to show the range of demand side resources assumed in the scenario just like they do for supply side resources.

Initial Response: Gridworks

The bubble chart [that PNM presented] may be included in the PNM IRP, maybe even I the Statement of Need section that describes the range. But, as PNM says, the bucket of types of resources are going be the focus. But [I'll ask PNM] to respond.

PNM continued.

We will have similar charts to the bubble charts included in the IRP, possibly in the Statement of Need, to help provide that additional color. As you saw on the slides [we discussed], we do have the range of DSM resources broken out. So, I don't know that we need to do anything different here in order to accommodate SWEEP's request.

SWEEP: Stakeholder Modeling Runs

[Will there be] a section in the IRP to discuss or show the stakeholder requested modeling run results, or requested scenario results?

PNM Response

There's certainly going to be a very detailed appendix that goes through all of the stakeholder input throughout our process, starting back to April of [2022], including a documentation of all the questions that have been asked. Everybody probably is aware now of the interactive Q&A section of our website where you can go and see all the previous questions and answers that have been asked.

In previous IRPs we have had a dedicated section on the results to talk about stakeholder modeling run requests, and we intend to do that this time. I think part of the question will be 'Do we put every single request into that section, or do we put the most informative requests there and leave some of it in the appendix?' But all of the information will be a part of the IRP filing.

Member of the Public: Stakeholder Input to the Statement of Need

With respect to the Statement of Need, as an external person, I haven't quite seen the last document that we are responding to and, particularly, the final recommendation that arises from the modeling. Whatever that final recommendation is, I think that we stakeholders would still like to review that and have an opportunity to read and perhaps reflect on it.

Initial Response: PNM

We will have another meeting on October 19 [2023] where we'll have additional information that's presented. So far, all of the trends of what the IRP model results are showing similar ranges of things across the different futures in terms of similar load growth type things.

Are you asking if you're going to get an opportunity to review PNM's final Statement of Need and Action Plan prior to it being submitted to the Commission?

Member of the Public continued.

I think that's pretty close to it--the actual final recommendation of the most cost-effective portfolio. Right now, it to me is still a little in limbo and, unfortunately, I will not be on the October 19 meeting. So, that will not be an opportunity for me to weigh in again.

PNM continued.

It is our intention to have drafts of the Statement of Need and the Action Plan to go through again at the October 19 meeting. Of course, after that meeting, we can still receive feedback.

The final version will be what is filed. I don't know that we're going to have a final draft that is going to be shared and have commentary period on it prior to us filing. That's what this entire process is for and certainly we hope to get a draft out so everybody can review it before we file. But I don't know that we'll have a full draft ready by the 19th, and we still do want to be responsive to additional feedback that we would get at that 19th meeting.

Member of the Public continued.

Will there be at some point a chance to read the full IRP draft before it's filed?

PNM continued.

We intend to try to make a draft of the IRP available for review prior to filing. What that exact date will be will depend on when we get all of the feedback back from the October 19 meeting.

I've had a chance for our internal senior leaders to review everything. And when they're comfortable with it, we will post a version of that to the website for review prior to filing.

At that point, it will be a review. If you want to submit comments, you're always, of course, welcome to but at that point in time, it's going to be in PNM's hands to decide where we want to go from there.

Gridworks continued.

So, let me add to that. Our intent is to send out whatever version of the Statement of Need and Action Plan is going to be presented at the October 19 meeting a few days beforehand so people can look at it. If there's interest in people having an opportunity to submit written last comments, even after the 19th, I'm sure we can leave that open for a couple of days for additional email input.

There won't be an opportunity to discuss those with the other stakeholders, but we can certainly allow that, but, as PNM says, that's not likely to be the final version. There's still quite a bit of work and review going on within the PM team before that can be considered as final.

And the stakeholder process by the Commission does not require stakeholder review of the IRP. The stakeholder inputs are on the modeling runs, the Statement of Need, and the Action Plan. There's not any formal requirement for the stakeholders to review the IRP prior to filing. But my hat's off to the PNM team for trying to get as much of that to the stakeholders, including the possibility of a draft before filing, but there's no guarantee.

Member of the Public continued.

But it's kind of hard from my perspective as a stakeholder to know what I'm responding to if I don't get to have something that's pretty much akin to the final version of the recommendations. I think that's the point where I have my biggest concern.

Gridworks continued.

That's a good point. I'm going to document that as a possible lesson learned or a best practice--something to change for future. So, thank you for voicing that and we'll document that as a stakeholder request.

We have heard that request from some other folks as well, and so we will definitely include that in our report to the Commission when we report on this process.

Gridworks added subsequently.

[Regarding reviewing the IRP report], the next clear opportunity for stakeholders to review the final document is after it's submitted; there's a 30-day comment period that is allowed for any public comment on that IRP.

So, it's not part of this facilitated process, but it will be registered as comments prior to the commission staff making any analysis or comment, and prior to the commission itself making a decision on accepting the plans. So, we want to make sure people knew that those processes are in place, that are available to folks, and if they should be interested in it, they can certainly have other opportunities [to comment] both on the RFPs that follow and the IRP report itself.

Advanced Energy United: Most Viable Scenarios

Which scenarios are most viable and or preferred from PNM's perspective? I don't really see that anywhere and I don't remember talking about that.

Initial Response: PNM

PNM's perspective is to keep as many options on the table at this point moving forward. So, the likely outcome is going to be something that resembles more of the kitchen sink type scenario in terms of the most cost-effective portfolio.

We do see that that performs very highly in terms of carbon emissions, present value of revenue requirements, reliability, all of those things, and diversity of resources is certainly something that is important as well. So, I certainly think that that's probably where we will end up until we get the final resiliency model results done and get across the finish line there. I think that's still up in the air.

But with the Statement of Need and the Action Plan, there's a little bit of a disconnect on those. Where the Action Plan is just talking about the next four years and the resource procurements for the next four years already have RSPs that have been issued, and we're currently evaluating those. And so, most of what will go into the Action Plan is going to be focused on the next step after that and what we think is most viable.

I think what we've seen from this IRP is that there are a lot of different types of technologies that can fill the void in that particular timeframe and ensuring that we keep an eye on the market and technologies as well as ensuring that we issue robust RFPs for that time period to try to make sure that we're not going to eliminate options that are viable is the best way to go forward.

Advanced Energy United continued.

And are there any particular scenarios that PNM is leaning towards?

PNM continued.

Yes, I just said that the kitchen sink scenario is likely going to be the one that we'll focus on mostly. It is not our intention to take any resource types off the table for competitive solicitations in the future. We want to see how technologies and markets develop around those technologies.

Advanced Energy United continued.

Thank you.

Gridworks continued.

[The slide decks from the last meeting that have all the different combinations of technologies] might be a good place to review those technology options within the kitchen sink.

PNM continued.

What we would say when we look at that, for example, if we see some long duration storage that makes sense, that doesn't mean we'll only consider if it's compressed air in the model results that we're only going to consider compressed air, but there are lots of different technologies that, depending on how their costs curves mature, in the overall operational parameters that can look like compressed air, and so we wouldn't limit it just to that.

Just like we wouldn't limit our look at natural gas options solely to aero derivatives, but we look at linear generators or potentially other technologies. So, what the IRP intended to do is provide us trends in a roadmap of the different types of technologies and resources that could get us there, but ultimately the real decisions are going to be made through the competitive solicitations where we see what the market will bear.

Gridworks continued.

[Here's the Slide "Five Scenarios for Phase 3 Modeling.] Maybe you can point to, say a few words about what you term the kitchen sink to help us understand what's included?

PNM continued.

The far right one is what we would say is the kitchen sink. And so, essentially, it's not taking virtually any technologies off the table. And the resulting portfolios from this scenario include a lot of different combinations of most of these, but not all of these resources.

So, if we were to issue an RFP based off of that, we would not want to limit it to any particular resource type or resource amount, but we would want to see, based on a competitive solicitation, what combinations of resources coming out of that will best build a need of the specific time period we're looking at and continue to keep all of our options on the table going forward.

So, we don't want to limit ourselves to just a subset of resources because they look okay in an IRP, when that does not have the binding resource decision making behind it, nor does it have competitive market data behind it.

Advanced Energy United continued.

Great. Thanks.

Pine Gate Renewables: Stakeholder Input to Action Plan

[Pine Gate Renewables has made some thoughts on the Action Plan, and we want to add to them today.]

We're very supportive of that kind of combined idea of committing to a 2026 RFP, the 2026 RFP for resources. I think in all of the modeling that we've seen shows that there were indeed a lot of developers like us looking to fill that need. So, having kind of a commitment there on the Action Plan side is exciting for us.

As it relates to that second RFP, my only comment there is just to keep our options open in terms of what resources are mentioned specifically there. Of course, the things that were mentioned there are pretty self-explanatory … I will note that longer lead time could involve traditional technologies--wind is mentioned and also solar. For example, Pine Gate is developing a project up in Oregon that's 1200 megawatts and that's going to take five years to complete.

And so, there are many technologies, if you get to certain scale, will take quite a while to construct, so my comment is to keep that language kind of vague, if it is going to be included, in terms of specific resources.

Also, thinking about transmission to specifically [a certain location for wind resources], we are in a transmission constrained market where, if New Mexico's not already there, it's headed that way. Solar resources will also need transmission built or at least upgrades to deliver to PNM's system. So, and that might be thought or whatever.

Just keeping that kind of agnostic statement around long lead time and maybe more referencing of four or five years, or some sort of near time to relate to when, what, and how you define a longer lead time resource.

[Also regarding] transmission modeling and access, we're really the ones that put in that comment about trying to have a commitment in the Action Plan from PNM to explore potentially a new software or system in the next IRP for transmission modeling. This was floated when asked for in this IRP and the response was "We'll get to that in the next one." So, we want a commitment to that. There was a comment that it might come at the expense of some other variation modeling because there's only so much that the computers can do and time that the computers can run with it.

But our focus as a developer is on thinking through transmission, thinking about transmission constraints on the system. So, we do simply prioritize transmission modeling over looking at maybe some more exotic resources that aren't as fleshed out as things like wind, solar batteries, the base technologies that have been defined in this IRP.

Related to modeling also, just data access on transmission. We threw a note in there on that.

There's been a mention of the FERC [regarding] national security. We need to make sure that there are rules that PNM must follow in terms of who can access data on transmission. I will note that our company signs confidentiality agreements to the specific FERC standard in the rest of the country. I

agree that there is a balance between a public process and making people sign confidentiality agreements.

We are comfortable with having some sort of statement in the Action Plan saying, 'We will open up transmission data, given NDAs or other requirements provided by the federal government or by FERC as it relates to that.'

In the past, potentially, there has been a note within an NDA saying, 'If you look at this, you can't bid in the future. Maybe that was from this last round and maybe that wasn't transmission data specifically. But we would like to be able to see that data and still be able to bid in the future. I don't know how we would sort that out, but that is one thing we would like to see committed to in the Action Plan.

Finally, I'm supportive of the modeling assumption discussion starting quite quickly after the completion of this IRP, and we would like to see a commitment to discuss ELCC modeling for certain resources. That has been something that we focused on in the past, and we would like to see stakeholder involved conversation on how to come up with those numbers and how to value capacity with the many resources that we are exploring.

Initial Response: Gridworks

Thank you. You've covered a lot of topics.

I would ask you to look at the worksheet on the Action Plan, if there are any wording changes--either in things that you would like considered now or things you'd like to consider in the next IRP that are more specific with a timeframe associated with it—you can send those to me by email by [October 9]. That would be great. Or put them in chat now, if you can, if you want to take some time to word it.

We're looking for clarity. 'Use a better transmission model' is pretty vague, so if you have something specific [provide it]. The same with 'shared transmission assumptions' Anything you want to give us that crisps up, or makes this language more specific, please do so.

There's not a guarantee that PNM will be able to act on it. This is, again, stuff coming from the stakeholders. They will consider it as a team and talk with their folks to decide whether it goes into [the Action Plan] But the more clear we can have that language the better. That would be my request.

PNM continued.

In terms of the RFP, specific language, suggestions around the instructions to bidders, is not going to be included in the Action Plan. The Action Plan would say 'We will issue an RFP for these timeframes and there will be a separate commentary period where you would be able to review and suggest changes to the language. Similar to this process, it's ultimately at the PNM's discretion what language we would include.

Frankly, I don't know that we would want to consider five, six, seven years out for solar, but you're certainly welcome to offer up those changes in the instructions to bidders language.

[Regarding] the overall modeling, we are open to starting a modeling process pretty quickly, and I'll have to talk to our folks internally about that, just due to the resources that are necessary.

In terms of transmission data, that's probably not going to happen. That's something that is governed by our transmission department and making that available publicly, especially to a developer, is not something that we've ordinarily done, and I doubt it's something we're going to commit to do in the future.

Certainly, there would be the opportunity to review modeling results. If we do start working in the transmission model, there are going to be some tradeoffs because of timing and other such things. But certainly on the developer side, if there's information that you are able to get that puts you on a competitive advantage, that would be something that we would not want to do, to allow through the competitive process. So, we've got to weigh and balance that.

The transmission modeling overall is going to be something that's going to take time to get right within the IRP context and we're certainly working through that. But I would say that to try to get the transmission modeling right within the IRP is going to take an additional six to 12 months of process time. So, that essentially means we're going to have to start doing that work on January 1, if we file on December 15, and we're going to have to make some decisions on where else we can soften our exploratory pieces in the IRP around the number of scenarios.

As I've mentioned, we don't want to take technologies off the table at this point because we think there are lots of other things that are going to be needed to reach carbon free.

Finally, on the ELCCs, we offered up a lot of opportunity in this process for folks to join early on and to get involved in that discussion. We're certainly open to that. We do think there's a very industry standard on the way to calculate ELCCs. It's not really something that you argue over how you do it; it might be arguing over what's the footprint you consider.

We all know we're going to the [Western Resource Adequacy Program] and so in the introduction to [that] going forward, [we] will have to change the different technologies that are done in the ELCC modeling and the different penetration levels. But in terms of the actual mechanics, there's no real dispute over how you calculate an ELCC.

Gridworks continued.

Is that helpful, at least in some boundary conditions that PNM has made?

Pine Gate Renewables continued.

Fairly clear, yes. We'll be sending you an email with some more specific language.

[Also], there's a comment on the PNM side of things [in the Action Plan] about planning for potential additions on PNM's existing plant sites. I will be suggesting in comments that commitment involves potentially making some level of data on those plan sites available to the third parties.

PNM continued.

That won't happen. We are not going to make our sites available to third parties. That is an unconstitutional taking of our property, and so, unless we were to sell that property for others, we will not make that available.

Gridworks continued.

Thanks for the clarification and thanks for the comments.

Member of the Public: Public Information on Plans and Technologies

I want to comment on a couple of things that are in [the Action Plan].

One of them is the time-of-day rate planning that I know PNM is doing. And it feeds into my other major concern that, as you know, I've been trying to raise throughout this process: a way to inform the public more about the way power is generated, the changes that are coming into the system as we are moving through the transition of fossil fuel.

I don't see this as entirely a PNM obligation. I think that we'll probably need other voices from the community to help convey some of this information. There needs to be reliable voices that actually have expertise, and to somehow engage media that reaches the public on a more regular basis.

I haven't figured out how to frame that [to include in the Action Plan document] but you all know that you've heard me say it too many times.

I think that time of day is exactly one of those issues where the public could benefit from a better understanding of what everything is going through.

And the third area that I wanted to reflect on has to do with some of the risks involved with some of the technologies--either in operation or at the end game when certain technologies need to be dismembered—like aged out solar panels. Some of the dangers of that get into the press about – particularly lithium-ion batteries and fire risk--something that in a heated climate in a desert area a lot of people are concerned about.

These are areas that [may not] fit in the responsibilities of the IRP, so I'd like to just have some kind of a general bullet in the Action Plan whereby PNM will be help find outlets for this kind of information.

Initial Response: Gridworks

That's great.

As the facilitators we're not supposed to be contributing content, but I'm going to take a risk and suggest that maybe the action would be that 'PNM would participate in an information effort led by others' or something about 'contributing information.' The point is that somebody, in addition to PNM, might need to lead this. That I don't know if it comes from the Commission, or it comes from the Governor, or comes from a state agency. Maybe there's an action that says 'If the state engages in an information effort regarding the transition of our electric infrastructure and the risks and benefits associated, that the utility would consider participating or offer information' or something like that.

Is that an area where you're thinking could be a possible action?

Member of the Public continued.

I think maybe that's the best that that we can ask the utility to do at this point. I do think then it may reflect back on the Commission itself to assure that the public is informed.

And I don't quite know what the Commission's own responsibilities are in this area. But for sure, we have a problem in this area and that's what concerns me.

[For example], last week when I listened to [a media program] on community solar, they really couldn't honestly state to the people on the call how power was being generated for them when the solar isn't producing and why people had to be on the grid. They really didn't come clean on that and that's troublesome.

I'm willing to go with a wording like you suggest. I think that's maybe as close as we can come.

PNM continued.

In terms of trying to get something like that [into the Action Plan], we've got to keep it focused on what's IRP centric as well as what PNM has control of.

So, if it's 'PNM will host a series of educational events' or 'PNM will provide support if the Commission were to open something up.' I think those are some ideas that we can get around putting in the Action Plan in terms of educational outreach and showing that we're trying to broaden the public's understanding of some of the issues raised. But having some very specific things in tangible items that we can say, "Yes, this is what we're agreeing to do," and we can then measure those in a compliance filing with the Commission.

The time-of-day rate in the stakeholder section [of the Action Plan] is really something that's not IRP centric. We are not in control of what rates get accepted by the commission. So, there's probably going to be some mismatch there of what we think we can accept in the IRP versus what's in the Action Plan versus what's written there [in the draft]. So, the things that we can do have to be within our control as well as they need to be tied to the IRP type things.

Member of the Public continued.

I totally agree with that. And when I made that comment about the time of day, I didn't mean to imply about the rate, as much as just the fact that this is a shift, which is so important, in the change of generation, that's not getting communicated as well as I think any of us would like to see. And that's where I really want to guide that, so in the future we get better inputs and more informed input.

PNM continued.

I think in terms of education, if it's 'PNM will at least advertise and host three workshops' or 'PNM will petition the Commission' or 'PNM, if the Commission chooses to open up a public-facing workshop, will provide support as necessary.' But you have something there that we can say, whatever the key items are we want to do, PNM knows what it is responsible to do in order to meet that requirement of the Action Plan.

Member of the Public continued.

And it could also be that the communities are developing in other areas where this issue could be one of many others. So, [for example], somebody is doing something on housing or something like that, and power would still be an issue [that] could be brought in somewhere.

Gridworks continued.

Thank you. We'll work with PNM to talk about this offline. We'll also document it so it would go in Gridworks report to the Commission about the need for this.

This has come out from our interviews with a variety of stakeholders who agree with you that information is not getting out there, in particular to inform those disadvantaged communities, low-income communities, about this transition.

So, I think there's something to be done there, and if we can't have something that really makes it tangible within the utilities control, we can put it in our Gridworks report to the Commission to suggest something be initiated on this area.

Member of the Public continued.

I'm fine with that. I thank you all for listening to me.

Gridworks continued.

We're glad to have your insights.

PNM continued.

Thank you.

October 19, 2023
Meeting #10

Gridworks: Dynamic Balancing Resources

A question about the center category, dynamic balancing resources and notice in the text that also describes demand response as well as shorter duration energy storage in that category. But I see the demand response in The low-cost carbon for energy resources. Does it show up in both of those categories? Or am I misreading the text?

PNM Response

No, you're not misreading the text and we will break those out separately before we get to the final resolution. When we have another update to this, we will see demand response in the dynamic balancing resource section and just energy efficiency then in the low cost, carbon-free energy, resource section, keeping in mind, once again, this is cumulative installed new capacity.

So, you would not see, the demand response capacity associated with the existing programs, only new program additions.

Gridworks: Gas in Dynamic Balancing Resources

I'm going to ask the same question related to gas. So, gas could show up in a couple different of these buckets. You had mentioned that it showed up in the firm generating resources, but could it also show up in the dynamic balancing resources?

PNM Response

If there was gas technologies that through our modeling, we saw being utilized more as a balancing resource, as opposed to a we'll call it a reliability firm generating resource, we would put some of those megawatts over into the dynamic balancing resource section, but predominant what we're seeing here is the gas additions are really only being utilized in the modeling when there are these renewable droughts or other things that show an acting more like an insurance policy or break glass in case of

emergency type situation. So we thought that would be better to put it into the firm generating resource bucket, as opposed to the dynamic balancing resource bucket.

And just to reiterate the point, though, that is just our new capacity editions. This does not show anything that has to do with the existing gas resources.

New Mexico State University: Long Duration Storage

[Regarding where the chart indicates] a combination of long duration and gas, do you have the ratio of each or is that still to be to be determined?

Initial Response: PNM

What we're showing here is 300 megawatts of long duration storage, defining long duration storage as 24 hours in duration or longer. And then there's 391 megawatts of gas resources that are hydrogen capable that are shown. So, right now, that's what our modeling showing, if you want to dig into the more specific results, please take a look at what's been posted on Venue.

Also keeping in mind, the IRP is not where we make resource decisions. This is a planning docent; it gives us some ideas, but the actual ratios, the actual types of resources, the actual procurements are all going to be done through competitive RFPs subject to our procurement.

New Mexico State University continued.

Okay, that was just simply a matter of misunderstanding the [chart]. Thank you.

PNM continued.

The actual documents are also posted on the Gridworks website if you want to download them and take a look at the source documents as opposed to just viewing it on the screen here as a screen share.

NMPRC: Kitchen Sink Scenario

PNM said that Figure 1 is related to the bubble charts from [September 28, 2023, when] you showed natural gas starting in 2028, a low amount, maybe a 100, even 200 megawatts, and it increases a little bit in 2032, and then, of course, more by 2040.

[And now in Figure 1] we see no new gas, just what you call the hydrogen ready gas in 2042. Can you explain the differences between the two sets of data.

Initial Response: PNM

That's what we tried to say at the outset, that these are related to the bubble charts. The bubble charts looked at all five scenarios in the CTP future. This is focusing in on the kitchen sink scenario.

NMPRC continued.

Okay, thank you.

And then on the kitchen sink scenario, going back to [August 31, 2023, Slide 26], this is the only information we have on this kitchen sink so far. You only have it for 2040. Then it shows CTs [combustion turbines] plus the linear generation.

Can we get the loads and resources chart now for the kitchen sink now that it's your most cost-effective portfolio?

PNM continued.

All that data is available on Venue and could be put together by utilizing that data. It's not our intention to put together a L&R table and distribute it prior to filing the IRP.

NMPRC continued.

Okay, so in your IRP we'll have an L&R table.

PNM continued.

Yes, that is one of the requirements by the regulation.

NMPRC continued.

So, staff would very much like, and we're requesting, that we get an L&R table for your preferred portfolio as soon as possible prior to filing the IRP. I know you've said several times that we can put that together on our own through the Venue pivot process. That's a little bit awkward, at least for me to do. I'm not trained to do that, and I asse there are other stakeholders that are not as well.

And then to be able to improve your Statement of Need or to support your Statement of Need, particularly for the early years, which is the next 5 years, what really matters is that it's hard for us to understand your cost-effective portfolio without seeing the annual loads and resources chart to start with.

PNM continued.

Thanks. I appreciate that. And we understand what you're saying. Similar to what we've said before, we're making all of the data available if you would like to manipulate that data to put together the charts necessary for you to perform your review. It's all available. We will try to get a draft report posted prior to Thanksgiving, but the L&R table is usually a product of the appendices of the IRP.

I think we've been making as much data as possible available as frequently as possible. And so, I don't know that we're going to drop everything and create an L&R table. At this point, we need to move forward and get our IRP ready for filing.

NMPRC continued.

Okay, thanks. Back to 2042, the 391 megawatts of hydrogen. Are you saying that the gas resources that are hydrogen capable all come on in that year or did they start coming on sometime between what we would see here 2032 and 2042?

PNM continued.

Those are just showing the amounts of total new installed capacity in those years. So, it's not stating that the 391 megawatts of hydrogen capable, CTs, or linear generators, would come online in 2042. but by the time 2042 occurs, that's how much is online. So, those additions could occur anytime between 2033 and 2042, and this modeling for those specific years for those additions could be found in the data on Venue.

NMPRC continued.

Okay, thank you.

And then just so we understand. new gas would not include possible extensions of save Valencia which would not be considered new gas, even though, I believe Valencia may be part of your 2026 to 2028 RFP.

PNM continued.

The assumptions that we've used in this IRP as well as all of our previous IRP is that when purchase power contracts expire, we model them as expiring and see what types of resources seem cost effective to replace that capacity. So, there's no determination right now on whether or not, we would seek to extend or terminate the Valencia PPA. All the analysis that we've done just seeks to say, 'Well, what types of resources, if we were to replace it, would be cost effective when?'

When we are looking at Scenario 3 that allows new gas additions, we do see new gas additions come in as the likely cost-effective replacement for Valencia. And so that would point out that in an RFP, we would still consider an extension of Valencia or other gas resources as potential replacements there.

NMPRC continued.

And then when I look at under from generating resources,2027, and there is no gas and also no long duration storage, does that mean you don't need any firm generating resources between 2027 and say 2032?

PNM continued.

No. The way that we would look at that is we don't need to add any new from generating resources by 2027. By the time we get to 2032, we have added 300 megawatts of long duration storage. That could have occurred in 2028 or 2029, all the way up to 2032.

We still do have through 2027 and beyond there a lot of firm generating resources already existing on our system. And so given our existing system, and the other additions that we'd be making in the near term, we would not see under this kitchen sink scenario the need for additional firm generating resources by 2027. We do see that need happen later.

NMPRC continued.

Okay, because we don't see a natural gas addition in 2032, is it reasonable to asse that between 2028 and 2032 there's no new gas?

PNM continued.

In that particular scenario, yes. That does not mean we are going to exclude from consideration the ability to add new gas resources in those years, depending on how the economics and other factors in the system play out over time.

NMPRC continued.

Right, because as you said earlier, this is just a planning guidance document.

PNM continued.

And through an RFP process, if there were natural gas resources that were available, and it beat out the deliverability and economic basis from long duration storage, you could see a request for natural gas resources.

Maybe that's the one of the key things that we're trying to use with this bucketing. We're not making a difference between the 300 megawatts of long duration storage and the 391 megawatts of hydrogen capable of natural gas assets.

That's all from generation resources, and by the time we get to 2040, we're probably going to need 700 megawatts at least of firm generating resources. And it doesn't matter if it's the long duration storage or natural gas or a combination of the two or just one or the other, we need those attributes.

And same thing on the cost energy resources. Over time, we're not going to make a big distinction between whether there's a little more or less energy efficiency, a little more or less solar, a little more or less wind or possibly some other renewable energy resource.

What we're saying is that over this time period, we're going to need approximately those amounts of low cost, carbon free energy resources, and it could be in different amounts so long as I meet the overall energy requirements of the system.

Western Resource Advocates: Updates Before IRP Filing

Will an updated Statement of Need be provided before the IRP is filed?

PNM Response

Yes, our intention is to try to get a full draft of the report posted to our website before Thanksgiving [2023].

And we're certainly welcoming any additional feedback comments, et cetera, between now and then by email as well as up to the point of filing. Depending on the comments and when we receive them, we will take under consideration whether we can modify the docents to work those in.

There are no more scheduled meetings or updates. We're going to provide another update to review with everybody. We've been going through the process now for a while. So, I would say continue to submit your comments and we'll review those and consider them as we finalize our report.

It is our hope to have a draft report available by Thanksgiving, more for informational purposes. We will still take feedback, but at that point in time, incorporating feedback becomes more and more difficult as we get towards the end.

This process has been ongoing since April [2022].

Western Resource Advocates: CO2 Per Portfolio

[Regarding] the information that would be filed in the IRP in the appendices, we're interested--and I think we've mentioned this before-- to see in that data annual CO2 tons for each portfolio, just as public data that's really easy for anybody to access--just annual emissions by portfolio, not just for 2032 or 2040.

Initial Response: PNM

First, I would say that all of that information is currently available annually on the data found on Venue. So, that all does exist already for you.

In the 2020 IRP. we did put together some tables for all of the different portfolios that we examined and one of the things included in those tables was annual CO2 emissions by year.

Western Resource Advocates continued.

Okay, great. I understand that data is online. Just thinking about how this is a critical data point, it's very useful to have it really accessible publicly even to people who haven't participated in this process and wouldn't be as familiar with going into the background data, Thank you.

PNM continued.

Take a look at Appendix J in our 2020 IRP. That is likely the same or similar format we would use this time.

Western Resource Advocates continued.

Fantastic. Thank you.

NMPRC: 2027 RFP

Back to 2027, to Figure 1, you've already built into the install capacity, the 2026 bid results. So, with the 2027 data here by low carbon, the solar, and then the dynamic balancing, the storage, is that representative of what you're seeking from the 2027 RFP?

Initial Response: PNM

The 2027 RFP is still being evaluated. You should not consider just doing simple math to say you can deduce from this plot what the 2027 IRP filing will look like. Once we've got a little bit further along in that process, we will be making presentations to our stakeholders, including staff, on what that resource request will be. But that draws the distinction between what the purpose of the IRP is versus what the purpose of an RFP is. This gives us some ideas.

It's very likely that the 2027 filing is going to be predominantly solar and storage, given what we know about previous RFPs and the landscape right now. But these numbers will not add up to the RFP request for 2026 and 2027.

NMPRC continued.

Okay, I was more interested just in the resource category of resource types. And what you said is that it's going to be predominantly solar and storage, so that that leaves the door open for something else in the firm generating category.

PNM continued.

It all depends on what the economics and other attributes of the resources offered into the RFP show.

NMPRC continued.

Okay, thank you.

Gridworks: Affordability

On page 1 of the Statement of Need, there's a description of the requirements and the overarching objectives; the topic on affordability is yet to be filled out. Could you talk a little bit about how the team plans to flesh out a little bit--the affordability objective?

PNM Response

I would say that's a bit of an odd one. And the reason I say that is affordable can meet a lot to a lot of different people. And when we're looking at system level analysis, what we're focusing on predominantly is the overall net present value of revenue requirements.

In looking at affordability, there are two or three things--and some of them are still waiting for feedback [from stakeholders] on. One is when we design the portfolios--and portfolios are always designed as a least cost portfolio subject to whatever the resource choices, constraints, and all the other regulations, et cetera are--so, by their nature, they're going to be least cost in that sense.

Now, the question then becomes if we were to say, as we just talked about for resiliency, 'Well, we don't want any gas, but we want a system that's going to be as resilient as one with gas in it,' are we willing to pay that additional amount of money and how does that interact with the idea of affordability compared to reliability or resiliency?

We're hoping to still get some feedback from stakeholders and how they view some of these tradeoffs so, we can fill out the affordability piece. But our commitment to affordability is making sure that we meet all of our requirements in the lowest reasonable cost way.

Gridworks continued.

Great, thank you.

Gridworks: Base Technologies

Can you just explain the difference in the two charts [in the Statement of Need]?

PNM Response

Option 1 includes base technologies and Option 2 excludes base technologies.

So, the difference between these two charts would be that the ranges on the above chart that includes the base technologies would allow the upper end or lower end of the range to be set based off of the scenario that only had the three base technologies in it: solar, wind, and 4-hour storage, recognizing that that portfolio, because of the limited amount of resources, would likely require so much more storage, as an example, or so much more solar, as an example. Do we want to allow it to create an upper end or lower end of a range that may not be representative of the bulk of the analysis.

So, Option 2 changes the ranges so that you are not having the base technologies only scenario set the upper or lower balance.

I don't think that PNM would say that the base technologies only scenario would be a preferred approach going forward, and likely is not the right approach, if given the risks associated with that portfolio.

Gridworks continued.

Okay, thank you for that.

SWEEP: Energy Efficiency

My comment is maybe more clarifying than substantive. For [Action Plan] Number 6, I'm wondering if it's possible to include energy efficiency in the main statement of that, so, like, 'evaluate the ability to create new energy efficiency, demand response, and other customer programs,' because I know it's mentioned below in the sub bullets, but I just wanted to bring it up top.

PNM Response

Yes, I don't particularly see any issue there. I think part of the question … is whether we would ultimately end up proposing those as resources through a resource filing or as energy efficiency resource through the energy efficiency plan. But PNM would have no issues … [Would this—edited--wording] work for you?

SWEEP continued.

Yes, that was what I was imagining.

Western Resource Advocates: Load Shifting and Load Management

I think you've sort of captured this already, but in that same section [of the Action Plan] where you just added energy efficiency, you're talking about advancing grid modernization efforts, including AMI conversion to support new customer programs in the future. Do you specifically envision that those are

going to be load shifting programs, or I think you could add, like, 'including load shifting or load management programs.'

I think that something that we would hope to see more in the future is utilities developing ways to forecast and estimate the load shifting potential on their system.

Not just like potential or demand response and potential for energy efficiency, but also the potential for programs to achieve load shifting and develop metrics for that. It's early for PNM to do it, but just to capture that within the next bullet, where you say flexible requirements. So, [perhaps] thinking about wording like 'load management and load shifting' could be included there.

Initial Response: PNM

Do you have some specific language you want to try to recommend? We can look at how it reads or is your comment more just in general what you'd like to see.

Western Resource Advocates continued.

In the second to last bullet, where it says, 'continue advancing grid modernization efforts,' where it says 'to support new customer programs' you could [add] 'including load management and load shifting.'

PNM continued.

My only question back then is, if we write it like this--including both load management and load shifting, do you believe that those two buckets cover everything? Or are we now being somehow restrictive of things that are not load management or load shifting?

Western Resource Advocates continued.

I think by saying 'including' it's not restrictive, but if SWEEP may want to comment on that and suggest that it should appear somewhere else. Your top bullet says 'to continue to develop and implement cost, effective energy, efficiency and demand side management,' but I think load shifting would be kind of a new element that's not captured in 'continue to develop.'

PNM continued.

Okay, I don't particularly think there's any issues with modifying the statement like that.

Western Resource Advocates continued.

Okay, thank you.

PNM continued.

One thing I'll point out here is that, of course, for anything that ends up in the Action Plan, we have to be able to substantiate with the Commission in progress updates and how we're how we're meeting these pieces.

So, the expectation from PNM is [not] going to be that we are proposing new load management and new demand load shifting programs as the measure of compliance. The measure of compliance here is to continue to advance grid modernization efforts. And so that's where we will be pointing the Commission to in meeting this objective.

New Mexico State University: Funding for Pilot Programs

I had submitted one comment that was related to point number 11 [of the Action Plan], which was not just get funding for a pilot project, but there are other ways to collect some of the same information, which is to get on board with somebody else's pilot project.

The way I thought you could do that is by engaging with the different agencies like the Department of Energy, ENREL [National Renewable Energy Laboratory], EMNRD [New Mexico ‘s Energy, Minerals, and Natural Resources Department], and even the trade groups for the different technologies. By participating in that you can state your requirements that are specific to New Mexico and system and get some feedback as to how their pilot is satisfying that. As well as by engaging with those groups you'd

be more likely to get bids for those technologies in your RFIs and RFPs because it did seem like some technologies weren't represented there.

This is just because we're in this climate of rapidly developing decarbonized technology, so I think you need to be a little more proactive in getting the companies to meet the needs in New Mexico and to bid on when we need the resources.

Initial Response: PNM

Do you have some specific language you want to go over mean? Is it a matter of saying 'create' and/or 'participate' in pilot programs? PNM is not going to go so far as to say we are going to do these things. That's outside of our control to say that we know we can participate in somebody else's program without not knowing what the program is or the clear objectives.

Similarly, we are not going to say that PNM is going to go out and seek specific conversations with specific developers of specific technologies. Whatever we do as a company has to be something that we would be willing to do for everybody. So, it would not be fair for to say, 'Well, we're going to specifically go out and seek geothermal developers to build relationships with.' We sent an RFI to market and got no responses, so it's up to the community to come back with what they think they can do.

New Mexico State University continued.

So, if it was specific language, I would say, 'Reach out to the DOE, ENREL NMNRD, experts on emerging technologies to see how PNM could participate in pilots they are setting up.'

Gridworks continued.

Could we offer something? So, it says 'explore opportunities for federal and state funding as available,' you could add on 'project collaboration.' So, you could say, 'explore opportunities for federal and state funding and project collaboration.' Would that suffice?

New Mexico State University continued.

Yes, I think I would just say ‘with experts in the relevant government agencies.’

PNM continued.

I don't think we want to be so prescriptive to say it's only government agencies. If we want to participate in a pilot program with APS because they have some ideas about how to use additional or excess energy from Palo Verde to generate hydrogen. I don't want to [exclude] those potential options.

New Mexico State University

So, ‘project collaboration with industry experts’?

Gridworks continued.

You could say ‘as available, including, but not limited to,’ and list a couple of entities.

New Mexico State University continued.

That's very legalese.

Gridworks continued.

It just leaves the door open, but you're trying to get people listed with whom you’re coordinating.

So ‘as available, including relevant [government] labs and others’ or something like that.

New Mexico State University continued.

Excellent. That's what I was trying to get at with my comment.

PNM continued.

I don't particularly see an issue.

NMPRC: Timeline for IRPs and RFPs

[Regarding the relationship between the IRP and the RFP], our understanding now is you have an active RFP--2026/27/28. You've selected your resources for 2026. it's still an outstanding consideration for 2027/28. Then, is the current RFP based off of the 2020 IRP?

Initial Response: PNM

I heard a few things there.

The current RFP that we have bids already submitted to PNM for were for 2026, 2027, and 2028. We've talked about the 2026 portfolio and that's going to be filed imminently. We're still evaluating the 2027 resources. The reason why we highlighted 2029 is there've been some questions as to whether we could reissue a 2028 portion of the RFP subject to this IRP and the procurement rules under the new rules.

There was no tie previously to IRPs and RFPs, so we can't say that the 2020 IRP served as the basis for the 2026/27/28 RFP.

We did take a look at what our expectation of needs were that came from the IRP, as well as other regulatory filings and analysis that we've done, to inform the megawatt amounts that we have put in for the years in that RFP.

NMPRC continued.

That's where we came down on this matter.

So now let's talk about the 2023 IRP. And so you file on December 15, 2023, and the Commission has 120 days to accept. So, that's about the middle of April. And then if we go to the RFP section of the IRP rule, it specifies that, based on your described Statement of Need, 'you shall issue the initial issue an RFP in the current IRP docket,' so that would be this 2023 IRP docket, and that would be within five months of the Commission's acceptance.

So that means to go forward with items 1 and 2 [of the Action Plan], you'd probably be issuing an RFP for 2029/31 by August 24 [2023]. I think that's about right.

PNM continued.

There are some other considerations to keep in mind as you review Section 17.7.3.12, which is the procurement portion of the IRP Rule. One: Let's also keep in mind that all three utilities in the state have appealed that portion of the rule to the Supreme Court. So that is still being vetted by the Supreme Court.

After we file the IRP and go through the 120 days of commentary period, once the IRP is then accepted, if we want to issue an RFP, we have to file the instructions to bidders and the form contracts in the IRP docket. There's a 21-day review period prior to us issuing the RFP, but there are also other provisions in there where you can seek variances from the five-month requirement.

So, there's nothing that says, if we don't issue an RFP within five months, we've got to wait until yet another IRP is filed. There are variance provisions that allow us to make timely issuances as necessary.

For PNM, we would [probably] seek to issue these RFPs closer to the May timeframe, not the August or later time frame. The timelines for things are getting tougher and tougher, given the supply chains. So, I don't think that we're going to wait that much beyond the 21-day period for instruction to bidder comments and form contract comments before we would actually release that to the street.

NMPRC continued.

Okay.

And then the relationship between an Action Plan period and then the period that you go out for RFPs, there's not a correlation there. Your Action Plan period is 2024/25/26, but, as you said, you're already in an RFP process through 2028.

So, you could go out in an RFP for, as you said, maybe 2028 again, but 2029 through 2031 or 2032 or whatever is your belief as to what's prudent for running the company.

PNM continued.

Were you asking me to clarify whether PNM believes there's a linkage between the RFP and the Action Plan period?

NMPRC continued.

I guess what I'm saying is that just because the Action Plan period is 2024/25/26, that obviously does not set your RFP period. Your RFP period is set based on whatever you think is prudent or what you believe is necessary.

PNM continued.

Correct. The Action Plan period is only three years. It is too short of a time period and too near term for there to be anything that would tie the Action Plan towards new resource evaluations for approvals. From the time we issue an RFP and evaluate it and go through the Commission filing process, it's generally a four and a half to five-year period at best.

NMPRC continued.

I hope my questions don’t seem too elementary, but these are matters we’ve been just trying to make sure we understand.

Gridworks continued.

So, did you have a specific language change you're recommending on 1 or 2 or are you just trying to understand the sequencing of the RFP with the IRP action period?

NMPRC continued.

The latter, please.

NMPRC: Exit from Four Corners

[Regarding number 3] the evaluation of the abandonment of Four Corners prior to 2031, that's a pretty big deal as everybody knows. And I guess it could trigger a an update to your IRP but it would certainly trigger a Four corners filing.

Initial Response: PNM

Yes, to your second question.

The current abandonment proposal for Four Corners was denied by the Commission, and that denial was upheld by the Supreme Court. So, if we want to exit Four Corners prior to 2031, PNM is going to have to file a new abandonment case. Yes. that's true.

There's no requirement to update the IRP if something changes; there is a requirement to file a notification of material change. And so, the question would then be whether PNM believes the modeling in this IRP was sufficient and robust enough to where it would have considered other Four corners dates, or whether we would actually have to file a notice of material change. I believe the requirement on a filing of a notice of material change is how that would change the Action Plan.

NMPRC continued.

Okay,

I haven't really looked at what we're calling the kitchen sink scenario, particularly in the early years, to see where it has the range or wiggle room to have early retirement or earlier abandonment of Four Corners. And I assume you've built that in or are considering that.

PNM continued.

We certainly are looking at different sensitivities that would examine different exit dates; we've talked about some of those throughout the presentation of modeling results.

The notice of material change references the entire IRP document, so if you want a specific citation to it, it's under 17.7.3.11.D. And it talks about the entire IRP and the Action Plan. It is not specific only to the most effective portfolio.

NMPRC continued.

Okay, great.

So, Four corners is modeled up until 2031 in the MCEP [Most Cost Effective Portfolio]. Is that correct?

PNM continued.

The majority of the analysis we've done has looked at Four Corners being in the portfolio through July 6, 2031, which is the end of the current fuel and operations agreement.

We have done some other sensitivities that have looked at a 2027 exit date, as well as earlier in the process, looking at some 2024 exits. So, the MCEP will likely still have Four Corners through 2031, but we will have run a sensitivity case that basically takes that MCEP and augments it to look at a Four Corners exit in the 2027 or 2008 timeframe, consistent with some of the requests from the stakeholders.

NMPRC continued.

Thanks.

NMPRC: Expiration of Valencia, Reeves, and Red Mesa

[Regarding] number 10--the implications of expiring supply contracts--Valencia, Reeves, Red Mesa, you're not meaning to imply it's a given that those contracts are retiring, that they would not be renewed?

Initial Response: PNM

We cannot make that determination in an IRP. Those determinations have to be made by the Commission.

If we want to use Valencia as an example, PNM would have to bring forward to the Commission a set of resources to replace Valencia. We would not make a decision about

Valencia without doing an RFP and other analyses to say, 'Well, what are the better or alternative options?'

Same thing with Reeves or Red Mesa. Similar to what was done with San Juan, as an example the 2017 IRP did come to a conclusion that there would be a benefit to our customers to abandoning San Juan in its entirety prior to the end of its useful life, but the actual ability to do so was not granted until PNM filed a case with the Commission.

NMPRC continued.

Okay, This keeps being a little confusing—or interesting--the relationship with the IRP filings to the RFP because Valencia is scheduled to retire in 2027 and you have an RFP out for 2026-28, So, by the 2026 IRP, isn't the outcome of Valencia already determined by the 2027 RFP?

PNM continued.

The 2027 RFP, no.

This gets into a little bit of the tie back to item 1 and/or 2. The Valencia contract is currently set to expire May 2028, and so it would be the 2028 portion of the RFP. If having Valencia in here, as an example, is confusing, we can certainly remove it.

Likely the decision on Valencia will have been made prior to the 2026 IRP being filed. Reeves maybe, maybe not. Red Mesa, certainly not. There are other things that are going to be on the horizon, especially interconnected to whether there's an ability to get out of Four Corners earlier or not.

So, I don't, I don't want to confuse folks. We are trying to put an example list of resources that are currently in our portfolio, but in the future, we'll need to have an examination.

NMPRC continued.

That's really helpful. And I appreciate the clarification on the voluntary retirement date. For some reason I had it in 2027, so nice to note it runs to May 2028. Thank you.

Pine Gate Renewables: Market Sales

In an ‘overbuild’ scenario, say to offer more reliability, does this modeling include market sales revenues from those plants and the hours they aren't needed by the PNM system in the present values presented?

PNM Response

Yes, so when we are modeling our system, if there's the ability to sell off of PNM resources to provide benefits for our customers, that's captured in the present value of revenue requirements under the understanding that when we build the portfolios, we don't allow the portfolios to be built to make economic sales.

Once a portfolio has been constructed to meet all of our internal load obligations, when we run the more detailed production costs, that will incorporate those additional sales revenues.

New Mexico State University: Correlated Outage Risk

It would be helpful to see how the correlated outage risk changes versus the portfolio without added natural gas plants.

Initial Response: PNM

Yes. I would say that if there's no new natural gas plants added, then all of the risks that you would see would just be associated with the regional aspects. There'd be nothing in terms of just PNM sole correlated gas outages because there's no more gas outages or no more gas really left on the system there.

The question would be 'How much are you relying on buying market power source from gas units to charge storage resources?'

New Mexico State University continued.

Yes, that makes sense. Do you know what portion of the risk that was?

PNM continued.

Given the very small amount of natural gas in PNM's portfolio by the time we got to 2040, the bulk of that risk is more related to being able to charge energy storage from the grid.

And we did a similar analysis to that in the 2020 IRP, so as you reduce the ability to buy market power in the evening you can cycle up storage for early morning ramps; that does lead to change in the overall risk.

New Mexico State University continued.

Yes, that's fascinating to hear you say that. It would be great to see it in the text of the IRP.

PNM continued.

To the extent we have time to work that up, unfortunately the modeling request deadlines have long since past, and trying to work in new results at this point would be difficult.

New Mexico State University continued.

I wasn't suggesting a new result. I was just [talking about] the verbal analysis of the result and what's impacting it--like you just said.

PNM continued.

Okay. Appreciate it.

NMPRC: Constraints and the Market

Basically, I was trying to understand when, by 2040, of course, you'll be constrained on what you can buy on the market, and when we have a utility that's artificially constrained, is that taken into account in that unserved load--the benefit of having the market when you are constrained on what you can actually buy from the market?

PNM Response

So, [regarding Slide 15], one, it did show the amount of EUE reductions when we had a market versus not having a market. And I don't think we're doing anything to artificially constrain ourselves. We're trying to know what the real risks are, given what the market will bear.

When we are allowing the market, we are modeling all of the generators, at least, within one tie line away of PNM's system. We're not saying we can only buy from non-carbon emitting resources. There's no requirement for that. The short-term purchase power is not taken into account for emissions purposes per the Energy Transition Act.

And so, we are modeling the transmission as we believe it's going to work. We're modeling line ratings as well as we're saying well, 'What type of market inefficiencies have we seen that we don't want to over promise and under deliver in times of a critical need.' So, we are modeling transmission constraints, and we are allowing purchases to come from any type of resource.

NMPRC continued.

Thank you.

Western Resource Advocates: CO2 Emissions

Will the IRP narrative clearly explain how CO2 emissions are calculated, including whether any market exports or imports are included?

Initial Response: PNM

The CO2 emissions themselves are just a product of generation and the release rate of emissions for that particular technology.

If you're referring more specifically to the CO2 intensity requirements per the Energy Transition Act, the Commission has not established its rules on how that is to be calculated. That's an ongoing process.

Western Resource Advocates continued.

Yes, thank you.

I'm definitely not asking you to anticipate where the Commission is going to land in that rulemaking, but just in the narrative to explain where CO2 is provided, just a simple explanation of how the model has calculated CO2--what's being represented there, just so it's easy to see if there's any distinction between what's presented in the IRP and what we may later find as a Commission adopted rule.

And I'm not saying that they should be aligned at this time, but just to know what is represented clearly in the IRP data.

PNM continued.

I was trying to differentiate because the calculation of CO2 emissions is purely the product of generation multiplied by a release rate for a given scenario.

If we're talking about how we're modeling the carbon intensity constraint, that's a different story,

Western Resource Advocates continued.

The carbon intensity constraint in your modeling that will be presented in the IRP.

PNM continued.

We're not anticipating putting anything out there that says this is a specific formulation of how we incorporated this constraint. We do intend to show the outputs of what the carbon intensity of the portfolios are.

Western Resource Advocates continued.

I'm just requesting that it just clearly state what the CO2 emissions that are shown in the IRP, just to clearly state what that's representing.

PNM continued.

Okay. I would take a look at what we presented in the 2020 in Appendix J.

If there's something there that you don't understand, or you would like to see done differently, perhaps a more specific request could be made. It's PNM's intention to show carbon emissions for each portfolio by year and as well as just show a carbon intensity output.

We did not in the 2020, nor is it our intention in this IRP, to put something out there when the Commission is still deciding how it wants to do the rule.

Western Resource Advocates continued.

Okay. I was not asking for that.

Table of Contents

April 28, 2022: Kickoff Meeting **1**

May 25, 2022 ..... **25**

June 8, 2022: Technical Session #1 ..... **115**

June 22, 2022, Technical Session #2 ..... **145**

July 6, 2022, Technical Session #3 ..... **189**

July 27, 2022, Technical Session #4 ..... **226**

August 17, 2022, Public Advisory Group Day **263**

September 13, 2022, Technical Session #5 ..... **281**

October 6, 2022, Technical Session #6 ..... **334**

October 17, 2022, Technical Session #7 ..... **369**

November 2, 2022, Technical Session #8 ..... **414**

December 15, 2022, Technical Session #9 ..... **447**

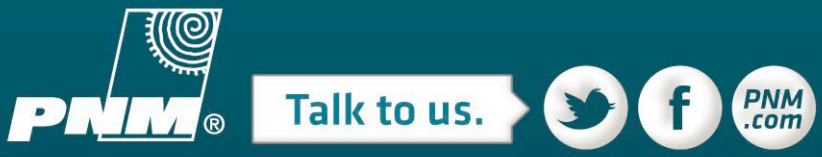
January 17, 2023, Technical Session #10 ..... **530**

February 15, 2023, Technical Session #11 ..... **609**

March 15, 2023, Technical Session #12 ..... **639**

PNM 2023-2042 Integrated Resource Plan

APRIL 28, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).



Nick Phillips
Director, Integrated Resource Planning

Mr. Phillips manages the PNM Resource Planning department and is responsible for developing PNM resource plans and the regulatory filings to support those resource plans.

Prior to joining PNM, Mr. Phillips was involved with numerous regulated and competitive electric service issues including resource planning, transmission planning, production cost analysis, electric price forecasting, load forecasting, class cost of service analysis, and rate design.

Mr. Phillips received the Degree of Master of Engineering in Electrical Engineering with a concentration in Electric Power and Energy Systems from Iowa State University of Science and Technology, and the Degree of Master of Science in Computational Finance and Risk Management from the University of Washington Seattle.

AGENDA

2023-2042 IRP KICKOFF MEETING

- Welcome, Introductions and Safety
- Current Events / Updates
- 2023 IRP Overview
- Open Listening Session / Stakeholder Input
- 2023 IRP Public Advisory Meeting Schedule
- Wrap Up / Next Steps

Energy + Environmental Economics (E3) is assisting PNM for the IRP filing

- **Founded in 1989, E3 is a 90+ person leading energy consultancy with a unique 360-degree view of the industry built on the depth and breadth of their experts, projects, and clients**
- **E3's resource planning experts have led numerous analyses of how renewable energy and greenhouse gas policy goals could impact system operations, transmission, and energy markets**
  - Experience includes studies of deeply decarbonized and highly renewable power systems in California, Hawaii, the Pacific Northwest, the Desert Southwest, New York, New England, South Africa, and other regions



Nick Schlag
Partner



Manfei Wu
Managing Consultant



Arne Olson
Senior Partner

Astrapé Consulting

- **Energy consulting firm with a focus on Resource Adequacy and Resource Planning**
  - Performs resource adequacy studies for utilities throughout the U.S. and internationally including California, MISO, SPP, ERCOT, TVA, Southern Company, Duke energy and others
    - Target Reserve Margin Studies
    - ELCC Studies for solar, wind, battery and demand response
    - Renewable Integration Studies
    - Licenses and provides consulting services using proprietary SERVM model



Nick Wintermantel

Principal



Chase Winkler

Consultant

ASTRAPÉ CONSULTING
innovation in electric system planning

MEETING GROUND RULES

01

- Questions and comments are welcome – One Person Speaks at a Time

02

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

03

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

CURRENT EVENTS

SINCE THE 2020 IRP WAS FILED

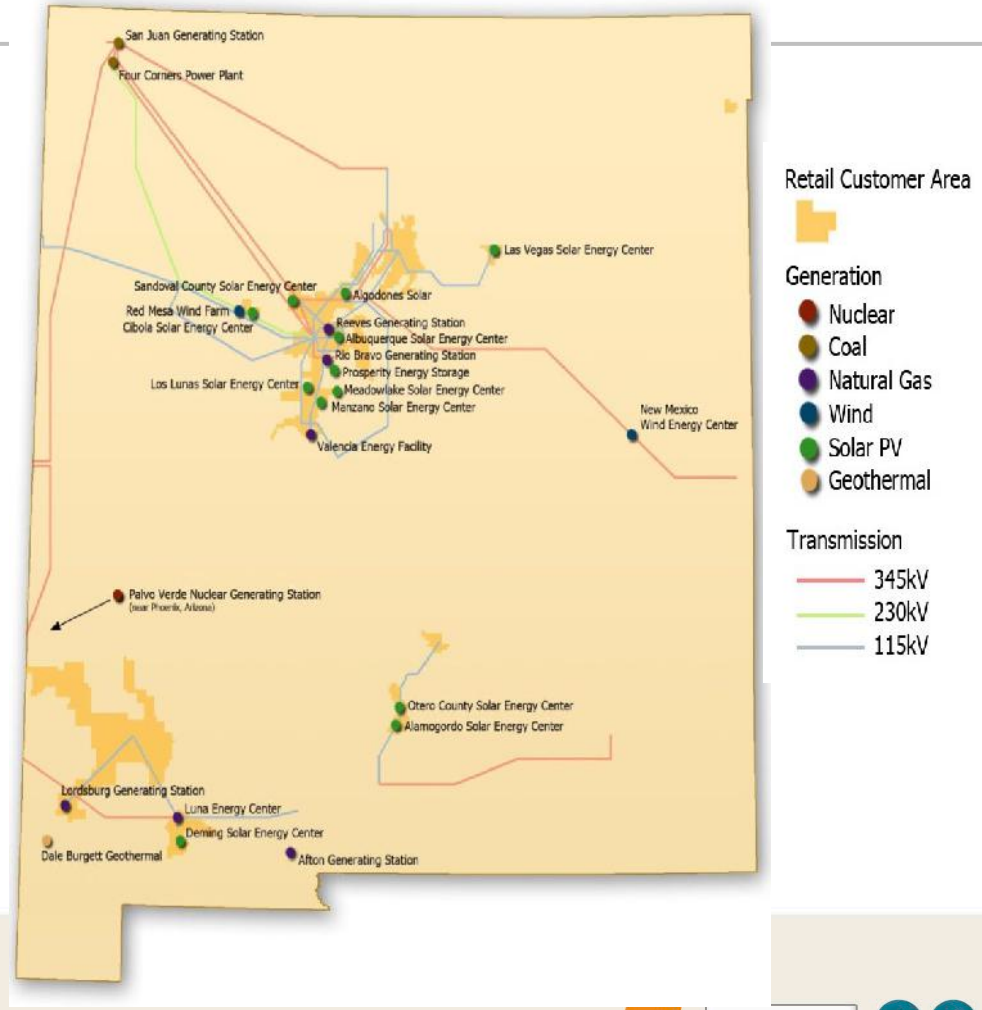
- PNM – Avangrid Merger (Case No 20-00222-UT)*
- Four Corners Power Plant Abandonment (Case No 21-00031-UT)
- Supply Chain Impacts on Recent Procurement Efforts
  - SJGS Updates (Case Nos 19-00195-UT/20-00182-UT)
  - PVNGS Updates (Case No 21-00215-UT)
- IRP Rule and Procurement Rule (Case No 21-00128-UT)
- Community Solar (Case No 21-00112-UT/22-00020-UT)
- Grid Modernization (Case No 22-00058-UT)
- Transportation Electrification (Case No 22-00085-UT)

*Will not affect the IRP

PUBLIC SERVICE COMPANY OF NEW MEXICO

OVERVIEW

- Only NYSE traded company headquartered in NM
- 1,500 employees
- Serving 525,000 customers (40 communities)
- 15,000 miles of transmission and distribution line
- 2,700 MW generation capacity
- Top quartile for ***affordability*** in the west and ***reliability*** in the nation.
- Top companies in the nation for diversity

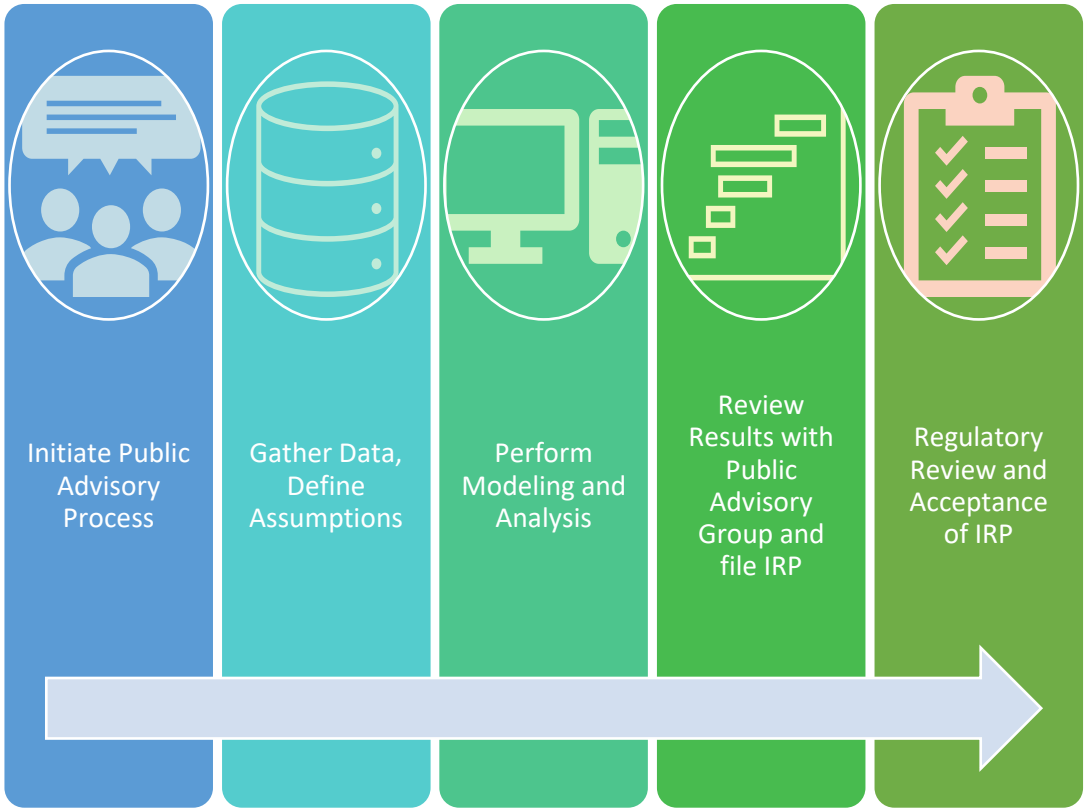


PNM Talk to us.

IRP OVERVIEW

TRIENNIAL DEVELOPMENT CYCLE

- PNM's IRP Examines a 20-year resource planning horizon
- Triennial planning cycle
- Create a Four-Year Action Plan
- Develop IRP with extensive stakeholder input and outreach through Public Advisory Process
- Most Cost-Effective Portfolio(s) developed with rigorous and robust modeling in accordance with industry best practices.
- File with NM Public Regulation Commission for review & acceptance



IRP OVERVIEW

GENERAL TIMELINE

Mar-Apr 2022
- Notify public and stakeholders of 2023 IRP process
- Kickoff meeting

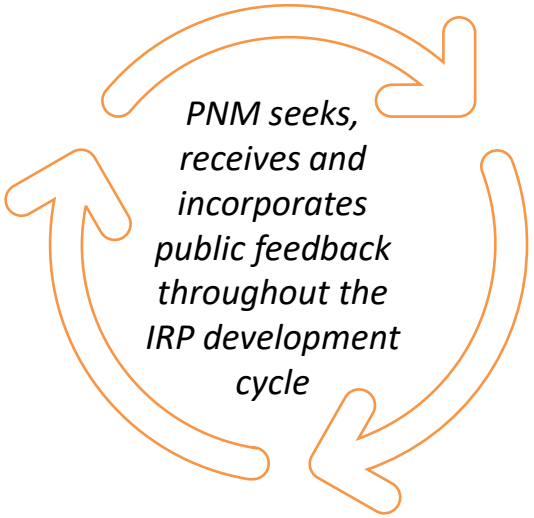
Mar-Sep 2022
- Setup analytic process
- Gather data
- Identify requirements

May-Oct 2022
- Discuss inputs and modeling assumptions

Oct 22'-Feb 2023
- Expansion plan modeling
- Reliability modeling
- Portfolio development

Jan-Mar 2023
- Review results
- Determine MCEP

Apr-Jul 2023
- Complete IRP
- Determine Four-year action plan
- File with NMPRC on July 3, 2023



IRP OVERVIEW

RULES, REGULATIONS AND LEGISLATIVE REQUIREMENTS

Legislation:

- New Mexico Public Utility Act – 62-3-1 et.seq. NMSA
- Efficient Use of Energy Act – 62-17 NMSA
- Energy Transition Act – 62-18 NMSA

NMPRC Rules:

- Integrated Resource Plans for Electric Utilities – 17.7.3 NMAC
- Renewable Energy for Electric Utilities – 17.9.572 NMAC
- Energy Efficiency – 17.7.2 NMAC

2023 IRP PUBLIC ADVISORY PROCESS

WHAT IS NEW FOR THE 2023 IRP?

The purposes of the public participation process are for the utility to provide information to, and receive and consider input from, the public regarding the development of its IRP. As PNM gathers data and receives inputs from internal business units and external consultants (ongoing through Sept/Oct), PNM is going to modify the Public Advisory process to solicit more feedback up front.

- Technical Sessions at the outset of the Public Advisory Process

  Focused groups to collaborate on technical modeling framework and details, may lead to additional data gathering, etc.

- Updates / summaries of the technical sessions will be presented after every two or three technical meetings to ensure all members of the Public Advisory Group help steer the process.

  This will hopefully help reduce dispute later in the process and focus the attention of the process on critical issues to further improve the IRP

2023 IRP PUBLIC ADVISORY PROCESS

WHAT IS NEW FOR THE 2023 IRP?

- We will still be hosting the more traditional Public Advisory meetings – this process upfront is to better align those meetings with the focus of our stakeholders. There will still be opportunities to submit modeling scenario requests, review inputs and outputs, discuss key results and findings, etc.

- If you have topics pertaining to the development of the IRP that you would like for PNM to address throughout the Public Advisory process, please raise them during the meetings or submit your ideas to IRP@pnm.com.

2023 IRP PUBLIC ADVISORY PROCESS

SUGGESTED TOPICS FOR TECHNICAL DEEP DIVES

- Reliability, Resource Adequacy and Resiliency
  - SW Resource Adequacy Study (E3)
  - PNM Resiliency Study (PNM, Astrape, E3)
  - ELCC Study & Synergies of Resources
  - Regional Reserves, Market Liquidity & Reliance on Market Assistance
  - Extreme Weather
  - Correlated Outages
  - Move to 0.1 LOLE
  - Use of Multiple Metrics (LOLE, EUE, etc.)

2023 IRP PUBLIC ADVISORY PROCESS

SUGGESTED TOPICS FOR TECHNICAL DEEP DIVES

- Load Forecast
- Renewable Resource Cost Development
- Long Duration Storage and Hydrogen Resource Modeling
- Transmission Analysis in the IRP
- Distributed Resource Modeling
- Scenario Tree Development
- Modeling of Existing Resources
- Candidate Resources / Technologies
- Others?

PNM Issued two RFIs seeking information on emerging technologies and new power resources. Initial responses are due June 15, 2022 and supplemental information can be provided through September 15, 2022.

2023 IRP PUBLIC ADVISORY PROCESS

WE WOULD LIKE TO HEAR FROM YOU - KEY QUESTIONS

1. What did we do well in the last (2020) IRP and where can we improve?
2. Any additional ideas for technical discussions?
3. What is the proper way to balance reliability, customer cost and accelerating the transition to clean energy?
4. How can we be more collaborative throughout the process with our public stakeholders?

Open Listening Session / Stakeholder Input

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: May 25, 2022*

Topic: Public Advisory Steering Meeting #2: Southwest Resource Adequacy Study and PNM Resiliency Study.

Start Time: 9:00 AM

CNM – Workforce Training Center*

5600 Eagle Rock Ave NE
Albuquerque, NM 87113
(505) 224-5200

*Dates, locations and topics are being finalized and will be posted on the website along with individual registration links.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: June 8, 2022*

Topic: Technical Session #1: Reliability Modeling

Start Time: 9:00 AM

CNM – Workforce Training Center*

5600 Eagle Rock Ave NE
Albuquerque, NM 87113
(505) 224-5200

*Dates, locations and topics are being finalized and will be posted on the website along with individual registration links.

PUBLIC ADVISORY TOPICS AND SCHEDULE

UPCOMING PUBLIC INPUT MEETING DATES*

June 22, 2022 – Technical Meeting #2

July 6, 2022 – Technical Meeting #3

July 20, 2022 – Steering Meeting #3

August 3, 2022 – Technical Meeting #4

August 17, 2022 – Technical Meeting #5

August 31, 2022 – Technical Meeting #6

September 14, 2022 – Steering Meeting #4

September 28, 2022 – Technical Meeting #7

October 12, 2022 – Steering Meeting #5

*meeting dates are subject to change. Dates are being finalized and will be posted on the website along with individual registration links.

PUBLIC ADVISORY TOPICS AND SCHEDULE

UPCOMING PUBLIC INPUT MEETING DATES*

October 26, 2022 – Steering Meeting #6

November 16, 2022 – Steering Meeting #7

December 14, 2022 – Steering Meeting #8

January 18, 2023 – Steering Meeting #9

February 15, 2023 – Steering Meeting #10

March 15, 2023 – Steering Meeting #11

April 19, 2023 – Steering Meeting #12

May 17, 2023 – Steering Meeting #13

June 14, 2023 – Steering Meeting #14

July 3, 2023 – File 2023 IRP

*meeting dates are subject to change. Dates are being finalized and will be posted on the website along with individual registration links.

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by May 18, 2022 for us to include them in the May 25, 2022 meeting discussion.

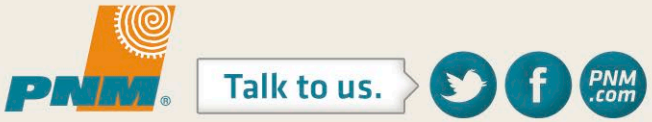
MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Southwest Resource Adequacy in the Desert Southwest and Supply Resilience in Planning for PNM

STEERING MEETING #2 **MAY 25, 2022**



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

AGENDA

2023-2042 IRP STEERING MEETING #2: RESOURCE ADEQUACY IN THE DSW AND RESILIENCY STUDIES

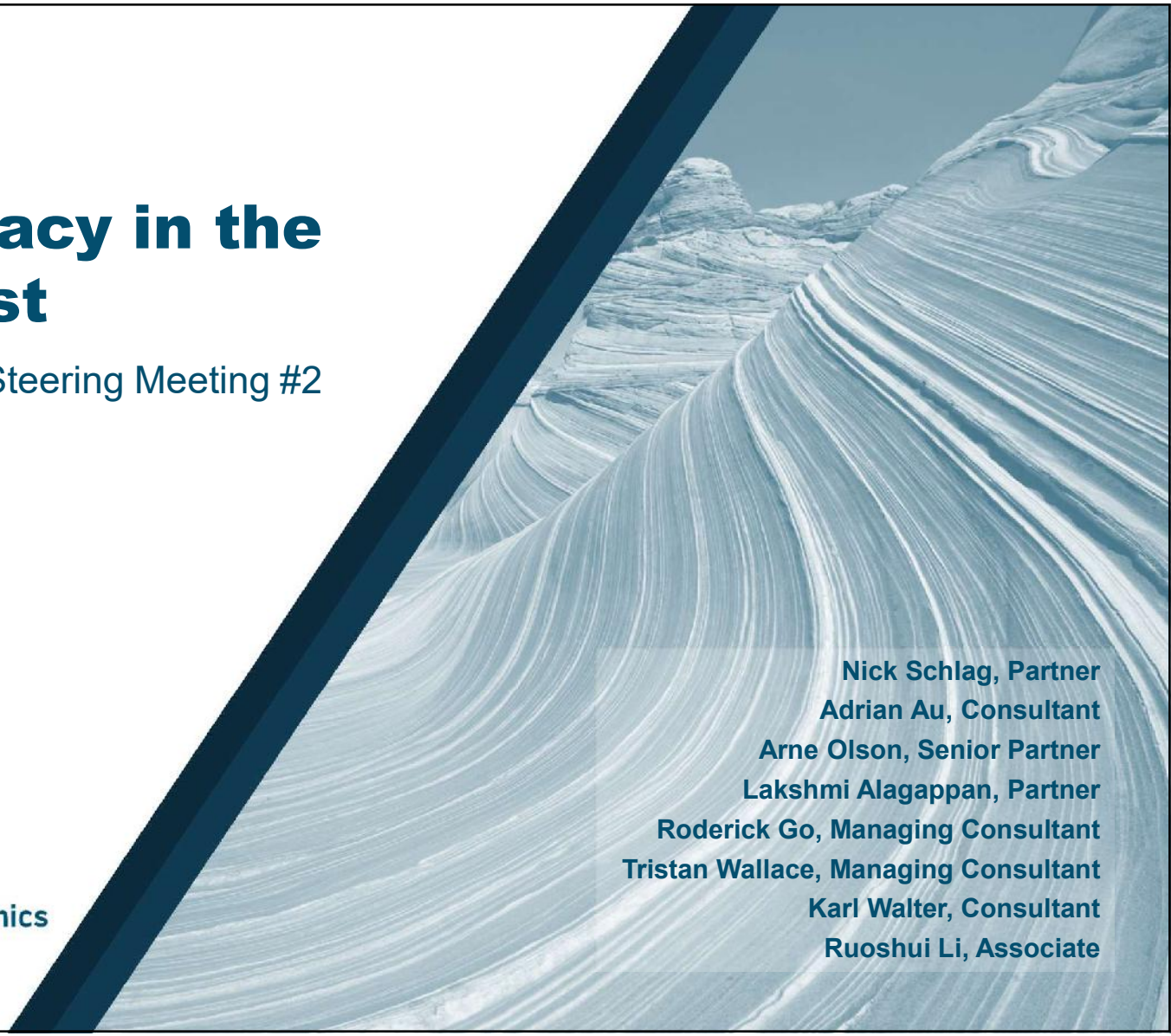
- Welcome, Introductions and Safety
  - Nick Phillips (PNM)
- Resource Adequacy in the Desert Southwest (E3)
- Supply Resilience in Planning for PNM
  - Nick Phillips (PNM)
  - Nick Schlag (E3)
  - Nick Wintermantel (Astrape)

PNM Talk to us.

Resource Adequacy in the Desert Southwest

PNM 2023 IRP Public Advisory Steering Meeting #2

May 25th, 2022



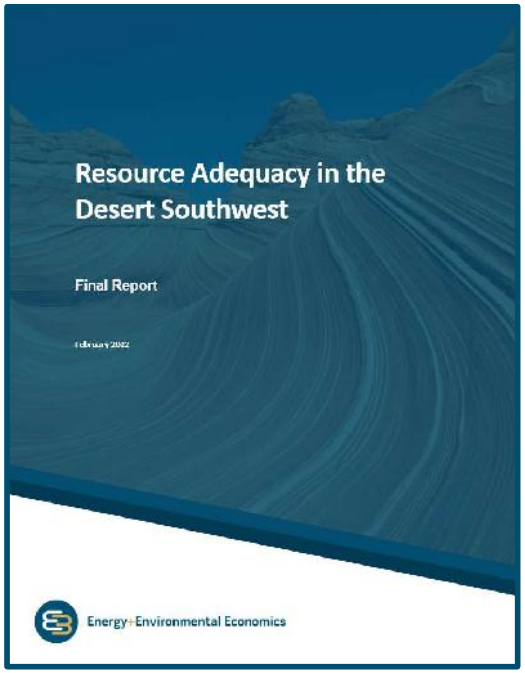
Nick Schlag, Partner
Adrian Au, Consultant
Arne Olson, Senior Partner
Lakshmi Alagappan, Partner
Roderick Go, Managing Consultant
Tristan Wallace, Managing Consultant
Karl Walter, Consultant
Ruoshui Li, Associate

Energy+Environmental Economics

Agenda

- Introduction & acknowledgements
- Study motivation & purpose
- Analytical methods & assumptions
- Summary of study results
- Key findings
- Questions

Final Report & Technical Appendices available on E3's website: www.ethree.com/publication

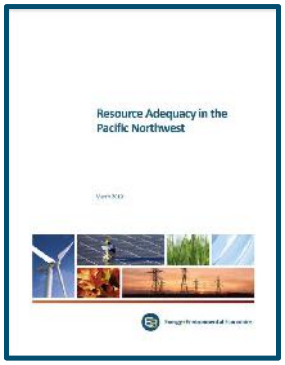


About E3

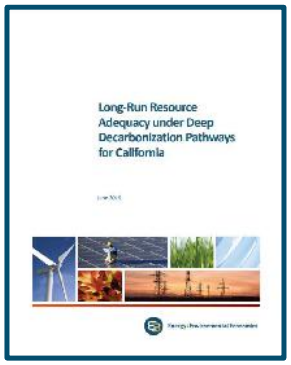
- Founded in 1989, E3 is a leading energy consultancy with offices in San Francisco, Boston, New York, and Calgary
- E3 works extensively with utilities, developers, government agencies, and environmental groups to inform strategy and key decisions
- Our experts lead rigorous technical analyses, develop innovative methods to study new problems, and provide critical thought leadership to the industry
- E3 is an industry leader in studying the resource adequacy needs in the transition to a decarbonized grid



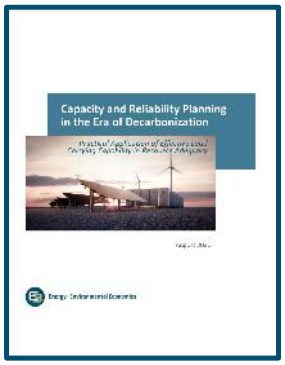
[Resource Adequacy in the Pacific Northwest] *(sponsored by a coalition of Northwest utilities)*



[Long-Run Resource Adequacy under Deep Decarbonization Pathways for California] *(sponsored by Calpine)*



[Capacity and Reliability Planning in the Era of Decarbonization] *(E3 whitepaper)*



Acknowledgements

Study Sponsors:

Arizona G&T Cooperatives
Touchstone Energy® Cooperatives

aps®

The Electric Company
El Paso Electric

PNM

SRP®

TEP

The study sponsors retained E3 to provide an independent assessment of the resource adequacy situation in the Desert Southwest region. The sponsors provided technical information and informed the development of study scenarios. E3 utilized data from the study sponsors and other sources to develop a Southwest resource adequacy model. E3 retained full editorial control over the report and is solely responsible for all contents.

Technical Advisory Group:

- **Aidan Tuohy & Eamonn Lannoye**
  Electric Power Research Institute
- **Bethany Frew & Gord Stephen**
  National Renewable Energy Laboratory
- **Branden Sudduth & Matt Elkins**
  Western Electricity Coordinating Council
- **John Moura**
  North American Electric Reliability Council
- **Kory Hedman**
  Arizona State University
- **Maury Galbraith**
  Western Interstate Energy Board
- **Pat O'Connell**
  Western Resource Advocates

Participation in the Technical Advisory Group does not indicate endorsement of the report's findings

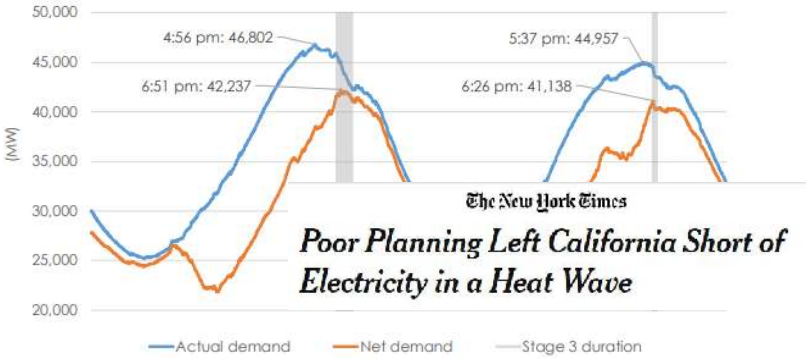
Study Motivation & Purpose



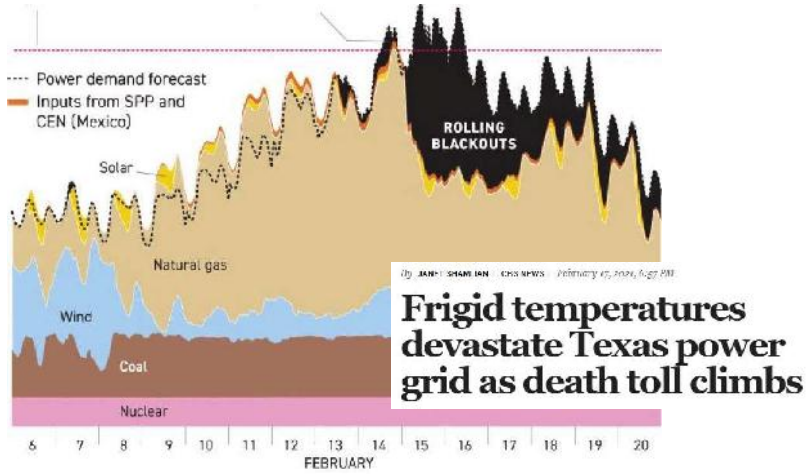
Energy+Environmental Economics

Planning for reliability is increasing in complexity – and importance

- **Transition towards renewables and storage introduces new sources of complexity in resource adequacy planning**
  - The concept of planning exclusively for "peak" demand is quickly becoming obsolete
  - Frameworks for resource adequacy must be modernized to consider conditions across all hours of the year – as underscored by California's rotating outages during August 2020 "net peak" period
- **Reliable electricity supply is essential to our day-to-day lives at home and at work – and will become increasingly important**
  - Meeting cooling and heating demands under more frequent extreme weather events is may be a matter of life or death
  - Economy-wide decarbonization goals will drive electrification of transportation and buildings, making the electric industry the keystone of future energy economy



Graph source: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf



Graph source: https://twitter.com/bcshaffer/status/1364635609214586882

Study purpose

- **The project's sponsors retained E3 to conduct a study to characterize resource adequacy in the Southwest region over the coming decade**

- **Purposes of this effort are threefold:**
  1. Examine the current situation in the Desert Southwest in light of recent challenges in neighboring regions and identify any immediate risks to reliability in the region;
  2. Characterize best practices for resource adequacy planning that will provide a durable foundation for utilities' efforts to preserve reliability within the region; and
  3. Demonstrate these techniques to evaluate the region's readiness to meet the resource adequacy challenges it faces in the next decade

Study Geographic Scope

Includes all balancing authorities in Arizona and New Mexico

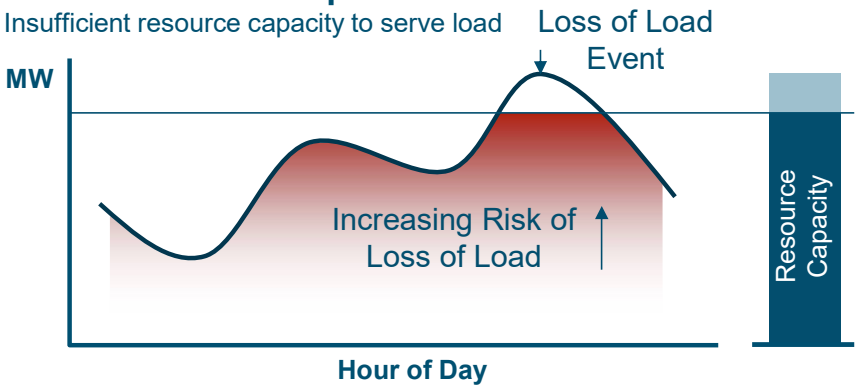


What is resource adequacy?

- **Resource adequacy is a measure of the ability of a portfolio of generation resources to meet load across a wide range of system conditions, accounting for variability of supply & demand**
- **Typically, electricity systems are planned to a standard where loss of load due to insufficient supply occurs very rarely**
  - The most common standard used throughout North America is a "one-day-in-ten-year" standard



Loss of Load Example



NERC Definition of Resource Adequacy:

"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

Source: NERC Glossary of Terms

Key trends in the Southwest region will reshape resource adequacy



Load growth

Expected 2+% load growth resulting from net migration, electrification, and new large customers



Planned coal & gas retirements

Utilities' planned retirements total 1,400 MW by 2025 and over 5,000 MW by 2033



Rapidly increasing reliance on renewables, storage, and DERs

Carbon-free resource additions driven by policy, customer preferences, voluntary commitments, and economics



Climate change impacts on extreme weather

Increased frequency and intensity of extreme heat events results in more frequent extreme peak demand



Increasing risk of sustained drought

Hydroelectric generation facilities susceptible to significant impacts under drought



Tightening Western markets

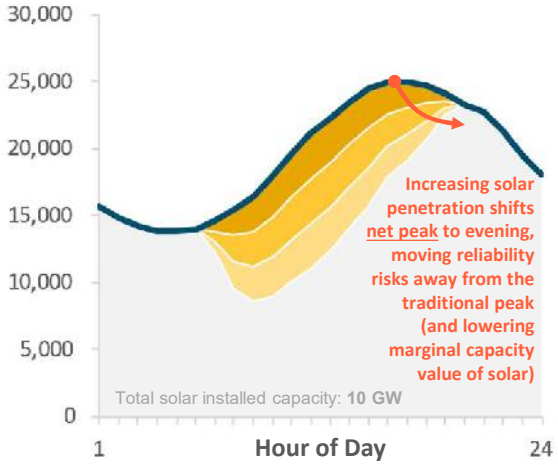
Changes & trends across the broader Western Interconnection reshaping market dynamics

Variable and energy-limited resources contribute to resource adequacy, but also add complexity

1

"Variable" resources shift reliability risks to different times of day

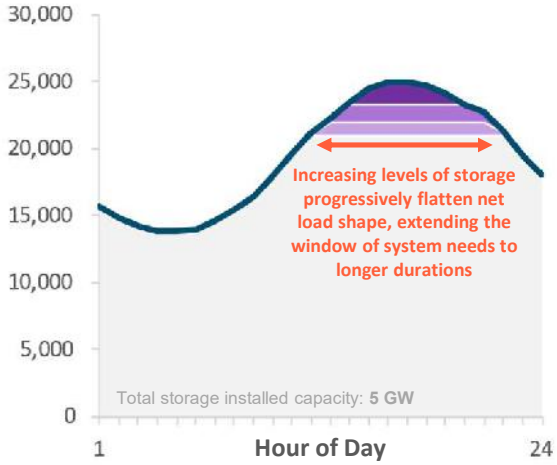
Solar Impact on Net Load
(MW)



2

"Energy-limited" resources spread reliability risks across longer periods

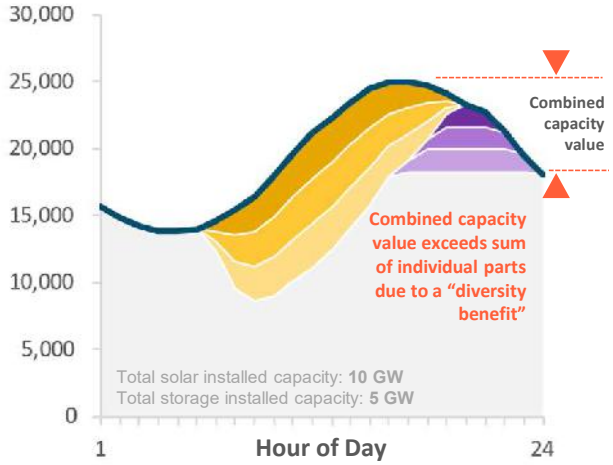
Storage Impact on Net Load
(MW)



3

A portfolio of resources exhibits complex interactive effects, where the whole may exceed the sum of its parts

Combined Solar & Storage Impact on Net Load
(MW)



Analytical Approach & Key Assumptions



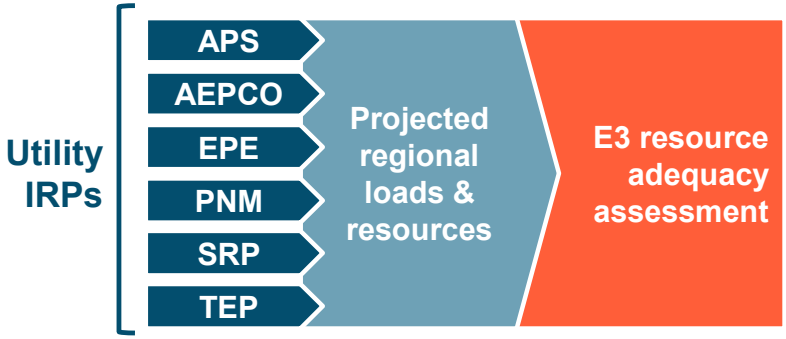
Energy+Environmental Economics

Scope of technical analysis

Three questions addressed in this analysis:

1. **How much capacity is needed to maintain reliability in the Southwest?**
   (measured against a "one day in ten year" standard)
2. **To what extent will utilities' existing & committed resources satisfy this requirement?**
3. **What additional resources are needed to ensure regional reliability?**

+ **This study builds upon the integrated resource plans of the Southwest utilities to address specific questions on how these plans will impact reliability within the region over the next decade**

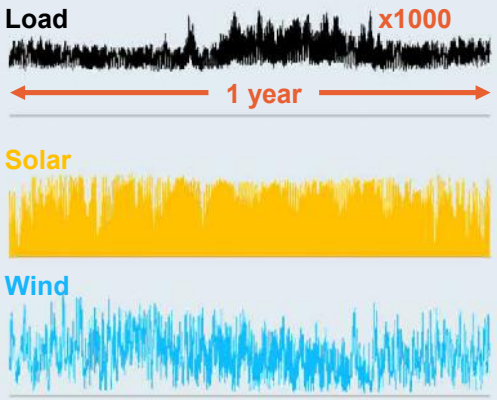


+ **Loss of load probability analysis used to study level of reliability achieved across the Southwest region, including metrics such as:**
  - Loss of load expectation (LOLE), expected unserved energy (EUE) and other statistical methods
  - A planning reserve margin (PRM) and effective load carrying capability (ELCC) values for different resources

Overview of best practices in resource adequacy analysis

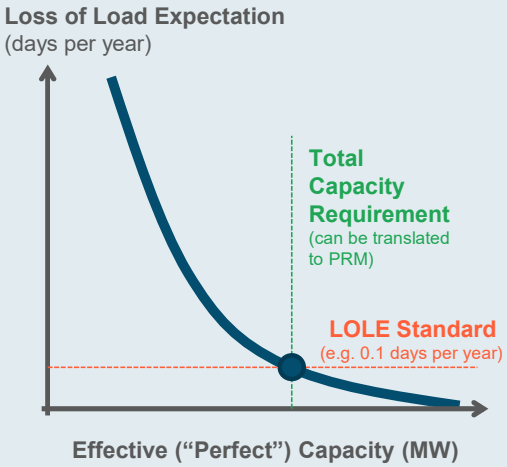
Develop a representation of the loads and resources of an electric system in a loss of load probability model

LOLP modeling allows a utility to evaluate resource adequacy across all hours of the year under a broad range of weather conditions, producing statistical measures of the risk of loss of load



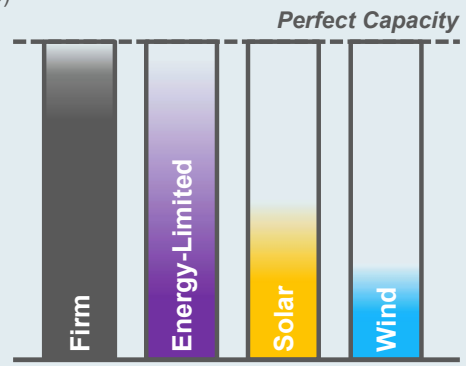
Identify the amount of perfect capacity needed to achieve the desired level of reliability

Factors that impact the amount of perfect capacity needed include load & weather variability, operating reserve needs



Calculate capacity contributions of different resources using effective load carrying capability

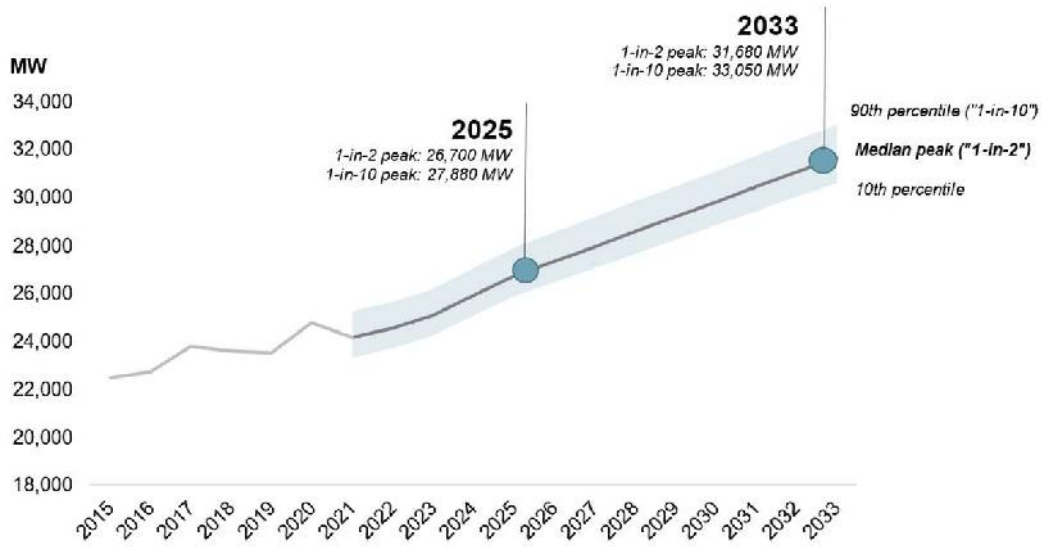
ELCC measures a resource's contribution to the system's needs relative to perfect capacity, accounting for its limitations and constraints



Peak demand is the primary driver of total capacity needs

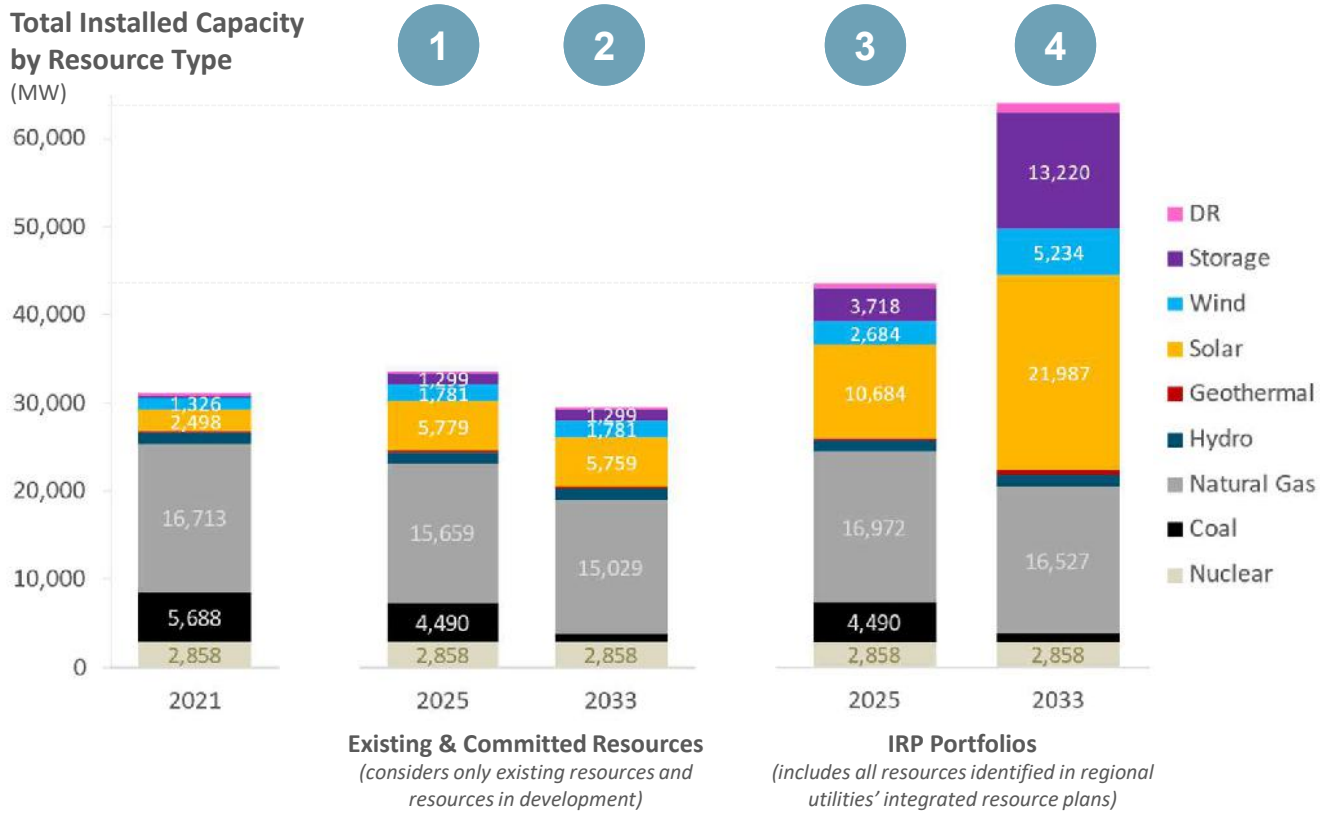
- **Regional load forecast derived from aggregation of individual utilities' forecasts and reflects:**
  - Demographic shifts and net migration to growing urban areas
  - Increasing levels of transportation electrification
  - Addition of new large customers
  - Impacts of future energy efficiency programs
  - Projections of BTM PV adoptions
- **In aggregate, regional peak demand is projected to grow at a rate of 2.5% per year**

Southwest Regional Coincident Peak Forecast (MW)



Scenarios and sensitivities

Four core scenarios examine regional adequacy of different portfolios:



Existing & Committed Resources
(considers only existing resources and resources in development)

IRP Portfolios
(includes all resources identified in regional utilities' integrated resource plans)

Sensitivity analysis explores additional uncertainties:

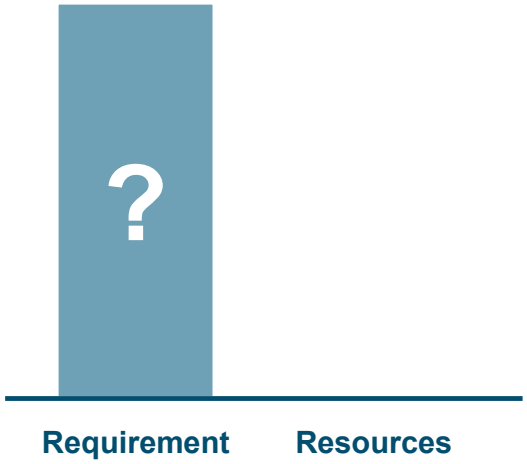
- + Battery storage performance
- + Hydro availability
- + Load impacts of more extreme weather
- + Natural gas generator performance
- + Interregional market dynamics
- + Timing of additions
- + "Summer stress test"

Study Results



Energy+Environmental Economics

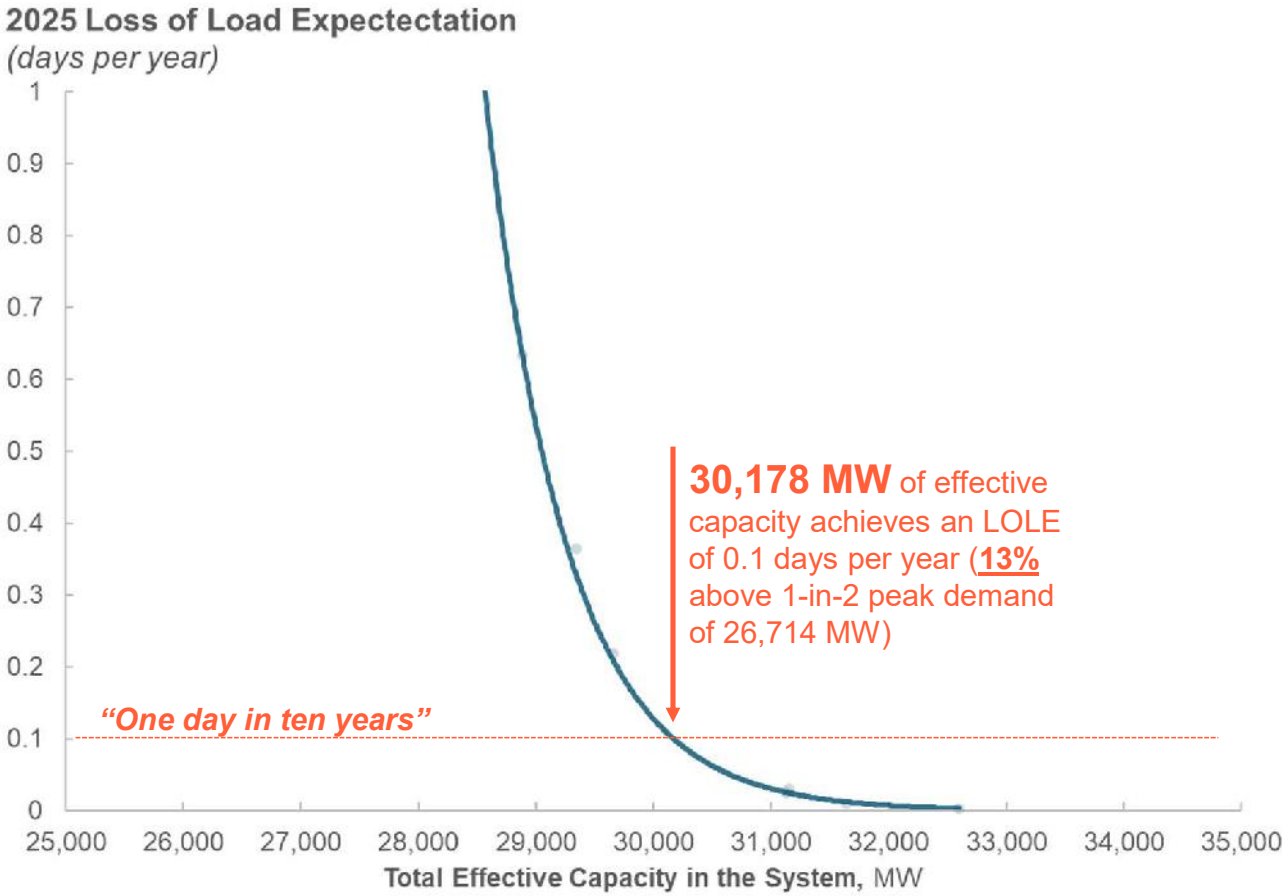
1. How much capacity is needed to maintain reliability in the Southwest?



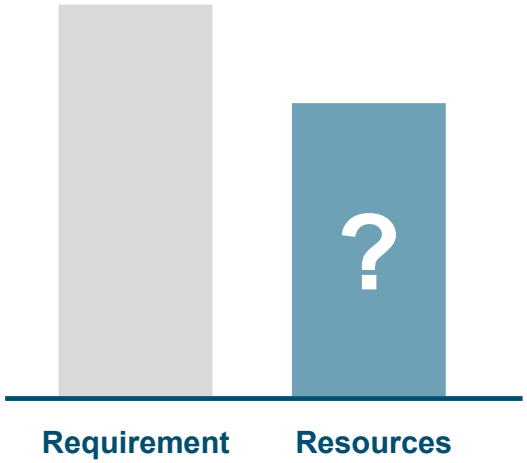
Energy+Environmental Economics

Achieving reliability requires 13% of effective capacity above the median peak

- **In 2025, achieving "one day in ten years" standard for the Southwest region requires 30,200 MW of effective capacity**
  - Increases to 35,800 MW by 2033
  - Reflects a **+13%** reserve margin above the regional coincident peak demand in both years
- **Expected frequency of reliability events grows rapidly below these thresholds**
  - Key implication: a rising capacity shortfall will rapidly lead to untenable frequency of load shedding events
- **Measuring need in terms of *effective capacity* makes this requirement is entirely independent of the characteristics of resources that to meet it**

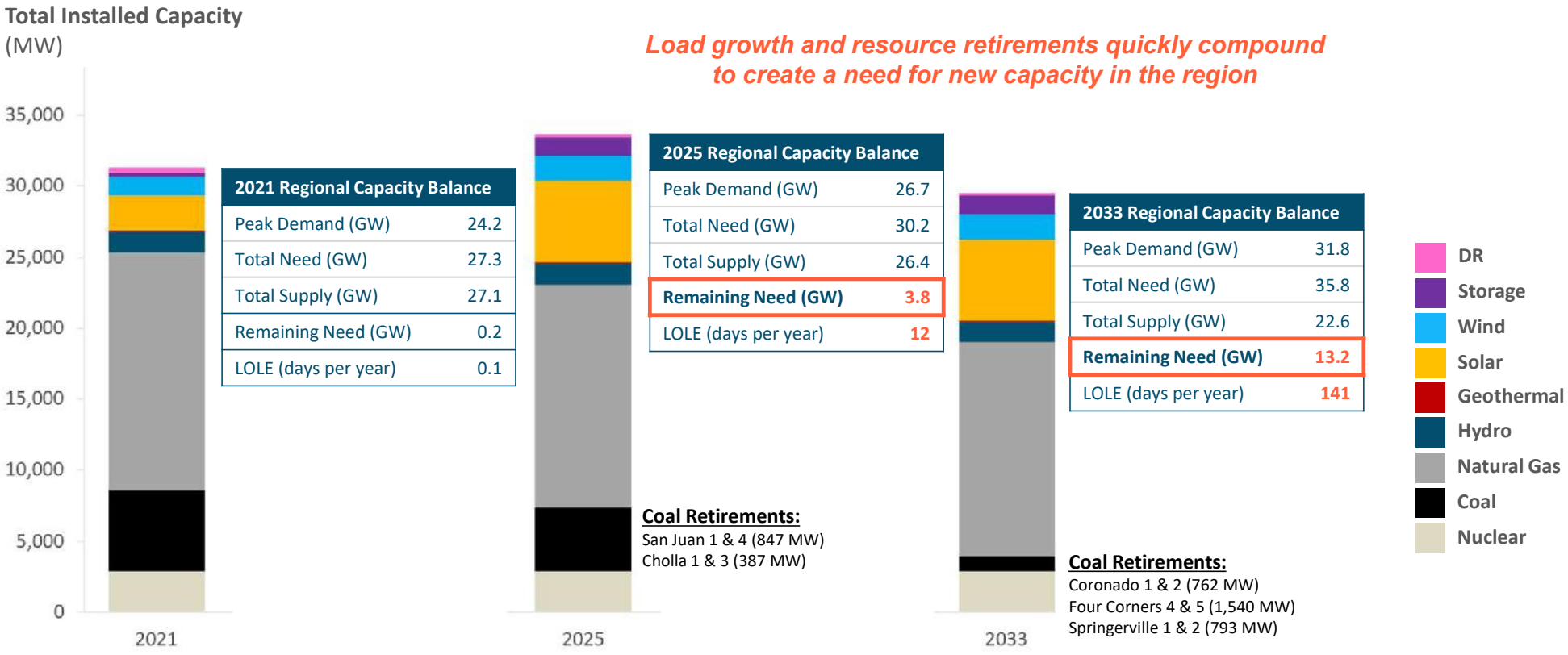


2. To what extent will utilities' existing & committed resources satisfy this need?



Energy+Environmental Economics

Existing & committed resource scenario summary results



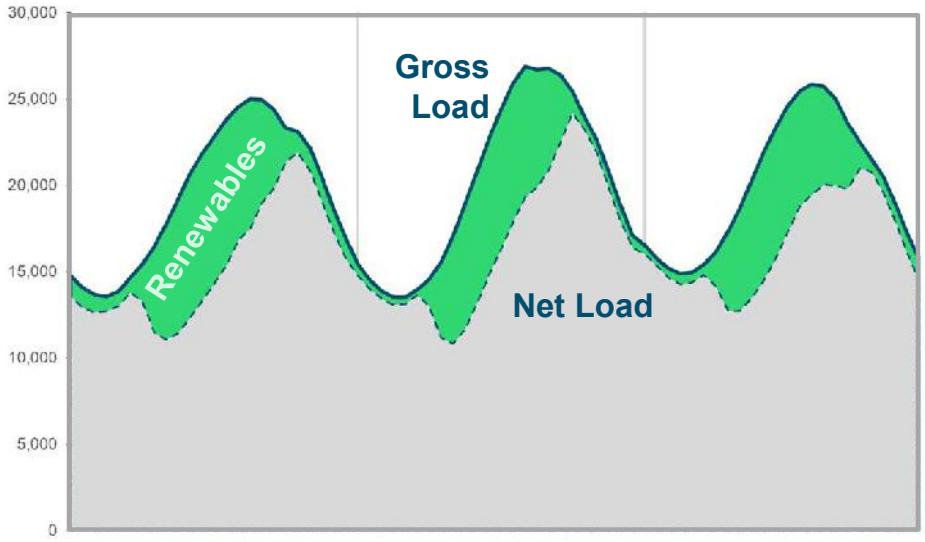
Notes:

"Total Need" and "Total Supply" are both measured in terms of "effective capacity"

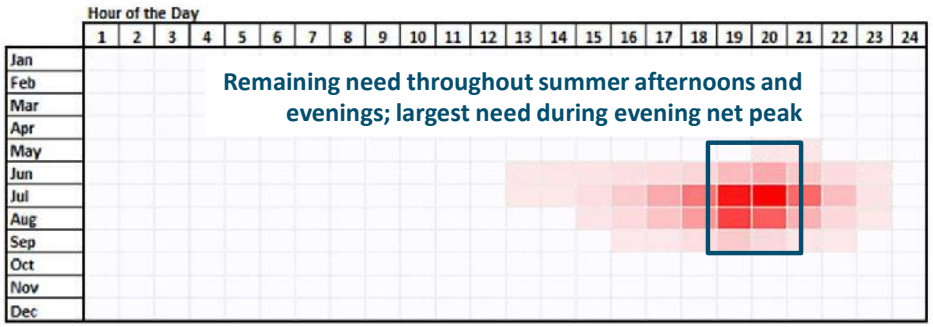
By 2025, the principal resource adequacy challenge in the Southwest is the evening "net peak"

- **With increasing penetration of solar resources, the highest "net peak" period occurs after sundown** *(i.e. the highest loss of load probability occurs when solar is not producing)*
- **This shift has direct implications for the relative capacity value of different types of resources**

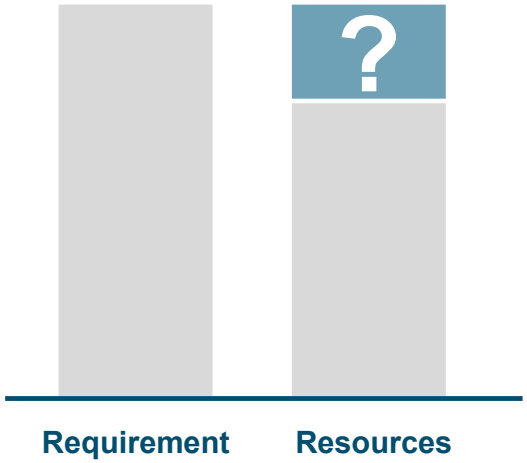
2025 load & net load on representative summer peak days
(MW)



2025 Loss of Load Probability
Existing & Planned Resources

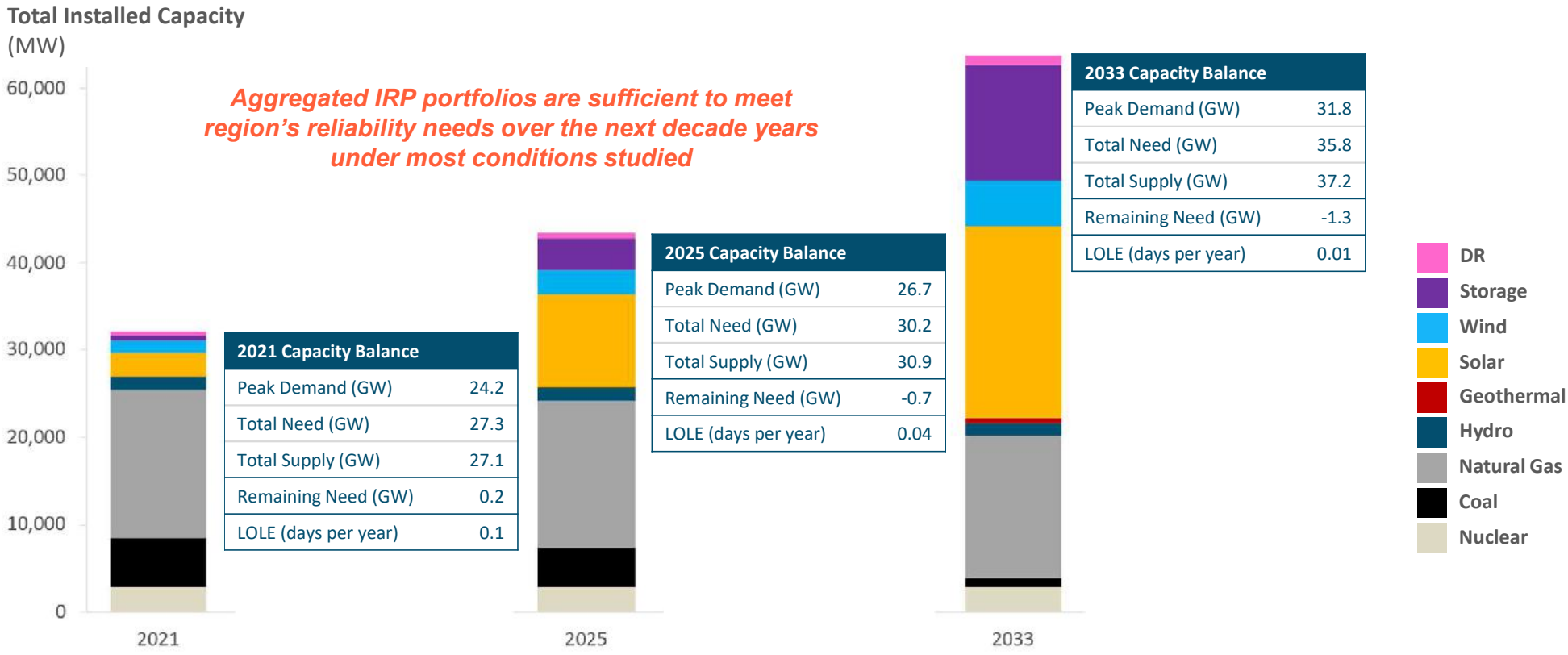


3. What additional resources are needed to ensure regional reliability?



Energy+Environmental Economics

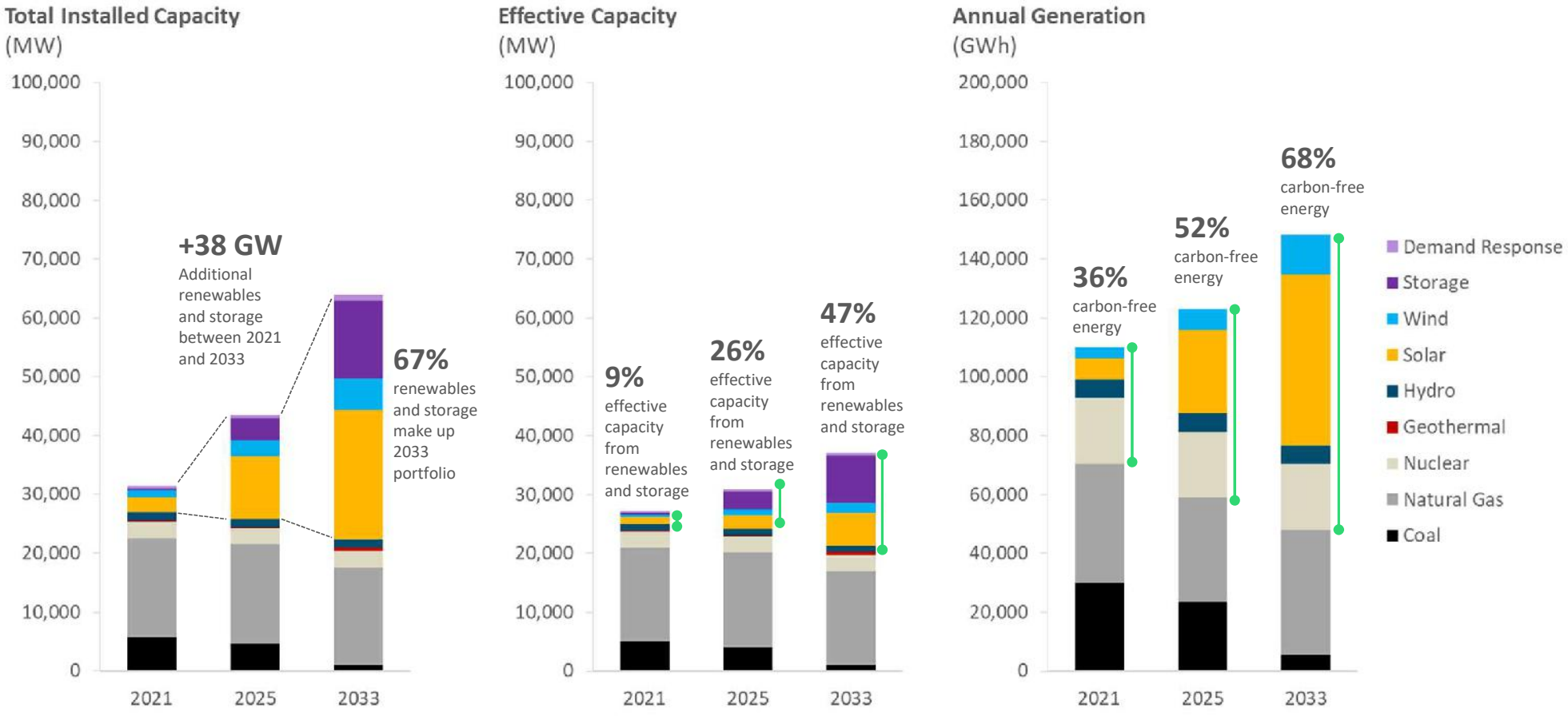
IRP portfolio analysis results



Notes:

"Total Need" and "Total Supply" are both measured in terms of "effective capacity"

Renewables and storage provide valuable energy and capacity, but existing conventional resources provide remaining reliability



Key Findings



Energy+Environmental Economics

Key Finding #1: Load growth & resource retirements are creating an urgent need for new resources in the Southwest

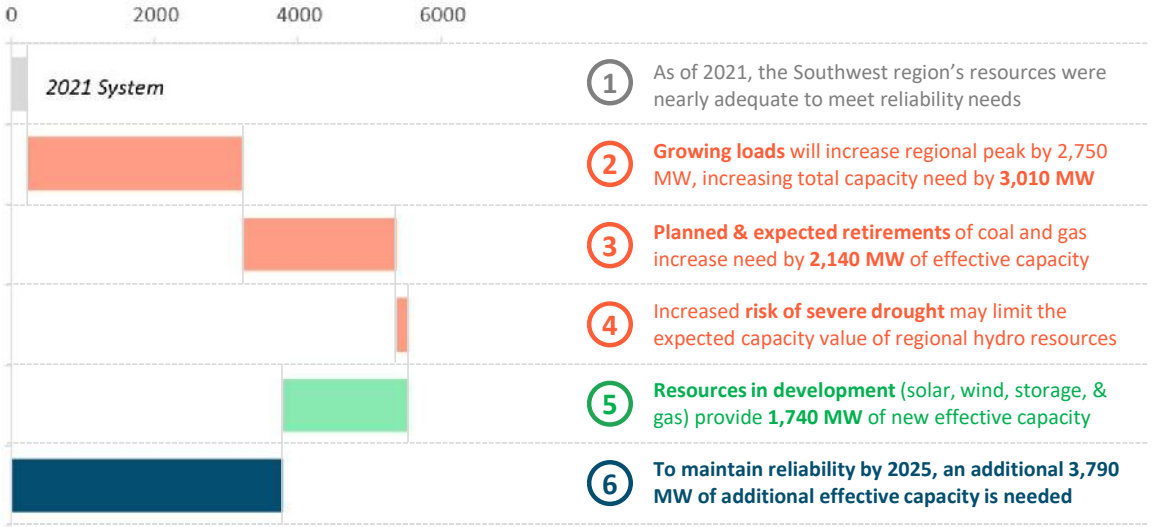
- **Existing & committed resources will be insufficient to meet the region's rapidly growing resource adequacy needs**

- **By 2025, approximately 4,000 MW of *effective capacity* will be needed beyond resources already in development**
  - Load growth anticipated by utilities will increase regional peak by roughly 700 MW each year, resulting in a 2,700 MW increase by 2025
  - Retirements of existing coal and gas resources are expected to total 2,500 MW of nameplate capacity by 2025

- **By 2033, the continuation of these trends will require a total of 13,200 MW of *effective capacity* to maintain reliability**

Changes in Southwest Regional Load-Resource Balance, 2021-2025

(Effective MW)



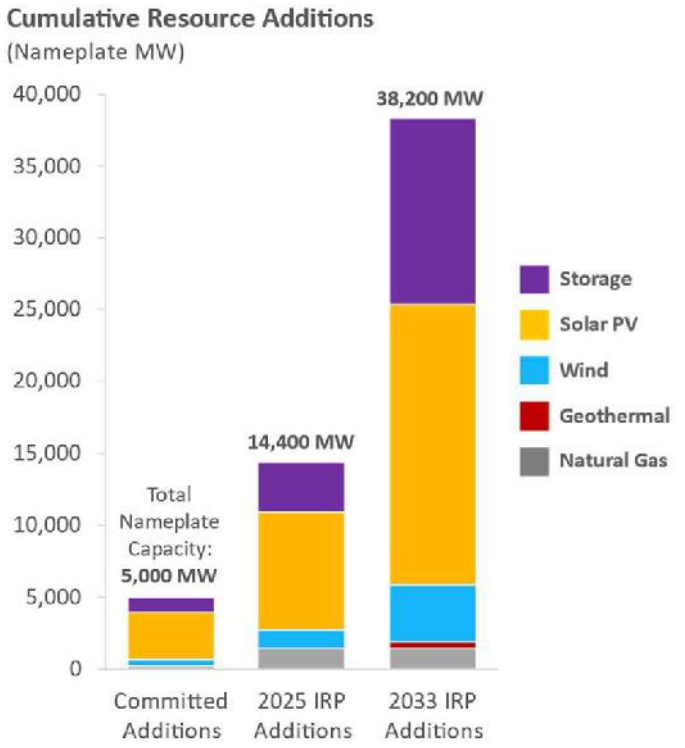
Notes

1. "Effective capacity" measures a resource's contribution to resource adequacy relative and is typically less than its nameplate capacity; the amount of new nameplate capacity needed to ensure resource adequacy will exceed – likely by a multiple of three to four times – the amount of new effective capacity needed
2. Resources in development within the region include solar (3,281 MW), storage (1,040 MW), wind (455 MW), and gas (228 MW)

Key Finding #2: Utilities' current resource plans have identified sufficient capacity additions to maintain reliability

+ **Utilities' IRPs have identified total additions of roughly 14,000 MW of nameplate capacity by 2025 and 38,000 MW by 2033**

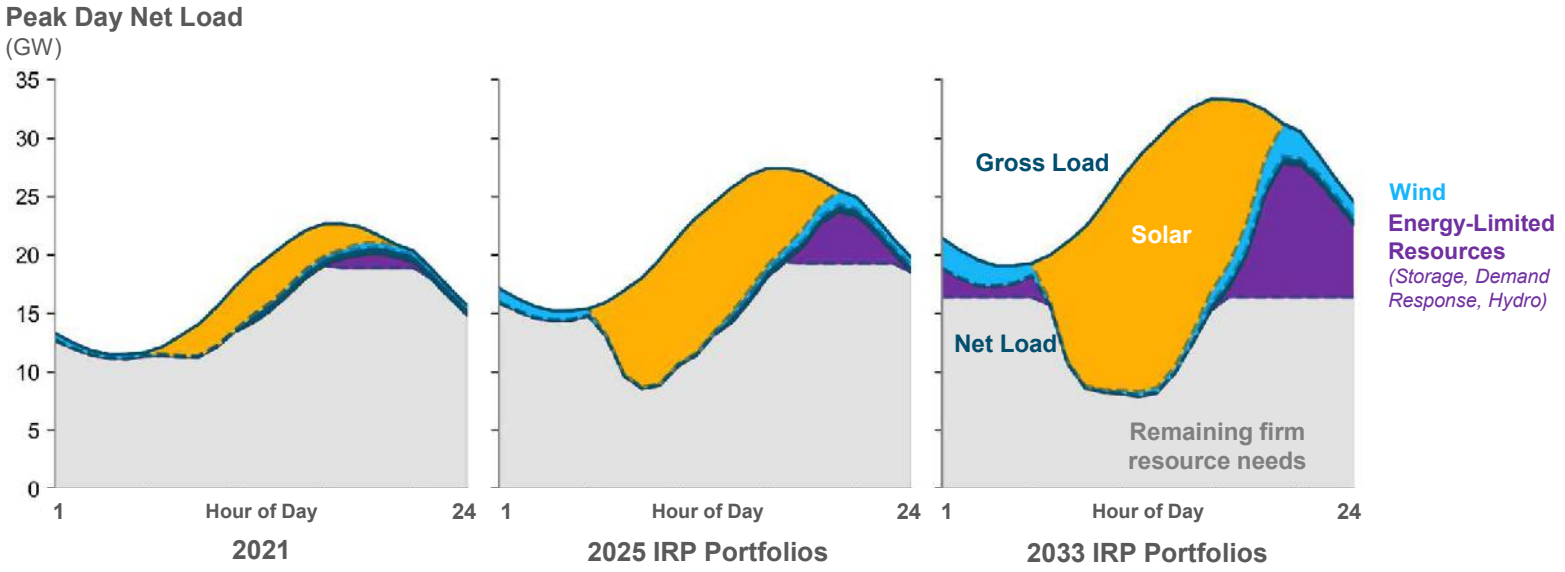
+ **The quantities and types of new resource additions included in utility plans are sufficient to maintain regional reliability under most scenarios**
  - If all resources included in utility IRPs come online during the timeframes identified, the region will maintain a small surplus of effective capacity over the next decade horizon under Base Case assumption
  - The amount of *nameplate* capacity needed to ensure reliability is much larger than the amount of *effective* capacity needed due to inherent limits on the capacity value of variable and energy-limited resources



Key Finding #3: A large share of the region's long-term needs will be met with solar, storage, and other "non-firm" resources

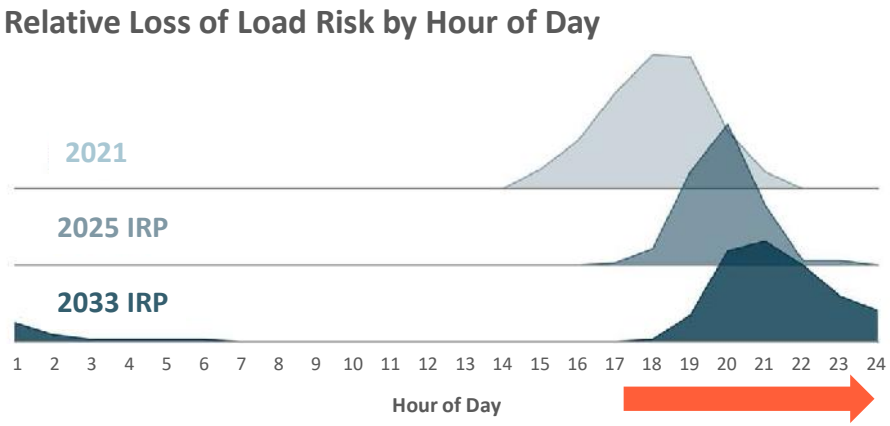
+ **A portfolio of variable renewables, storage, and other energy-limited resources can provide a significant contribution to regional resource adequacy needs**
  - Capabilities of solar and storage are particularly well-suited to matching high summer peak demands

+ **Non-firm resources will account for an increasing share of regional resource adequacy needs:**
  - Roughly 25% of regional needs by 2025
  - Roughly 50% of regional needs by 2033



Key Finding #4: Even as solar and storage grow, the region's remaining firm resources will be needed for reliability

- **By 2025, the evening "net peak" hours will become more constraining than the historical late afternoon peaks due to saturation of daylight hours with solar energy**
  - Additional solar added after this time will provide limited capacity value (<10%)
- **As penetration of storage increases, risks to reliability extend deeper into the evening and nighttime, indicating a need for resources that can deliver energy to the system for extended periods overnight**
  - As length of risk increases, the marginal capacity value of four-hour energy storage by 2033 will decrease to approximately 50%
- **Because of their ability to produce energy on demand for sustained periods, existing firm resources – including nuclear and natural gas – will continue to play a key role in meeting regional needs**



The changing composition of the portfolio impacts the timing of reliability risks:

- High levels of solar shift risk to the evening net peak
- Storage "flattens" the net peak, extending risk into nighttime

Key Finding #5: Substantial reliability risks remain as the region's electricity resource portfolio transitions



Climate Impacts

The possibility of significant changes to regional load patterns, e.g., due to climate warming, may increases the need for capacity to meet load during heat waves



Battery Performance

Battery storage has not yet been widely deployed at grid scale, and if it does not perform as idealized in this study, could be less effective as a capacity resource

Recent examples of extended plant outages at existing battery storage projects due to heat or fire provide warnings



Renewable Variability

As the region's supply becomes increasingly reliant on variable resources, weather variability introduces operating risks, including possible sudden, large drops in renewable energy output or extended renewable droughts



Fuel Supply

Reliance on just-in-time delivery of natural gas creates fuel security risks

The interstate natural gas pipeline system does not operate to the same reliability standards as the electricity system, and fuel deliveries have been interrupted during extreme cold weather events



Timing

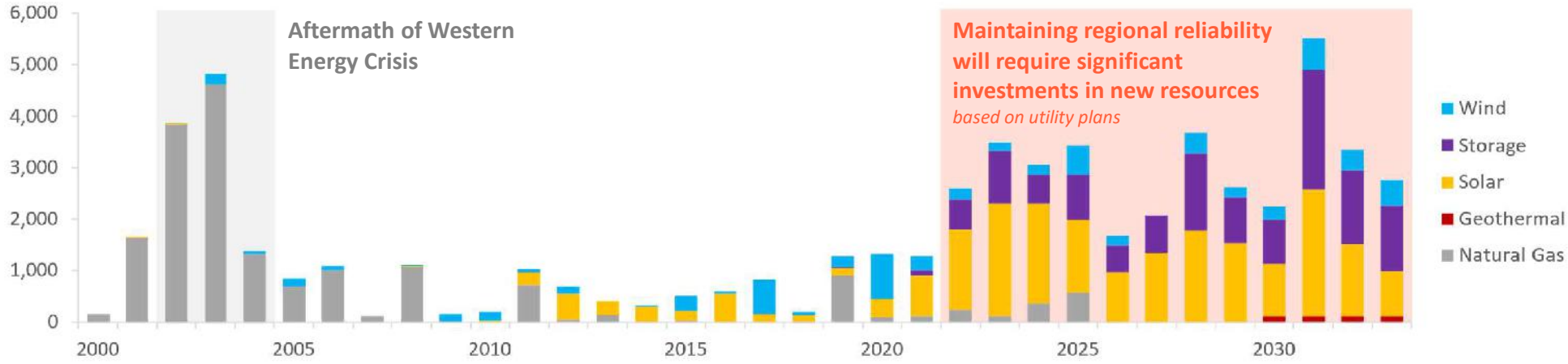
Processes for new resource development typically span multiple years

Project delays or cancellations could result in temporary resource shortfalls

Maintaining reliability will require immediate and sustained action over the next decade

- **The rate of new resource additions required in the next ten years is nearly unprecedented in the history of the Southwest**
- **With project development timelines measured in years and near-term supply chain risks looming, advance planning and prompt action by utilities are needed to avoid falling behind in the transition**
- **Utilities, regulators, developers and stakeholders will share responsibility for working cooperatively to ensure new resources are in place as needed**
  - Plans for new resource additions should account for reasonable risks of project delays and cancellations
  - Failure to develop new resources in a timely manner will either result in (1) a degradation of reliability or (2) the need to retain existing plants with scheduled retirements

New Installed Capacity Additions by Year (Southwest Region)
(Nameplate MW)



Thank You

Questions?

Nick Schlag, nick@ethree.com

Adrian Au, adrian.au@ethree.com

Energy+Environmental Economics

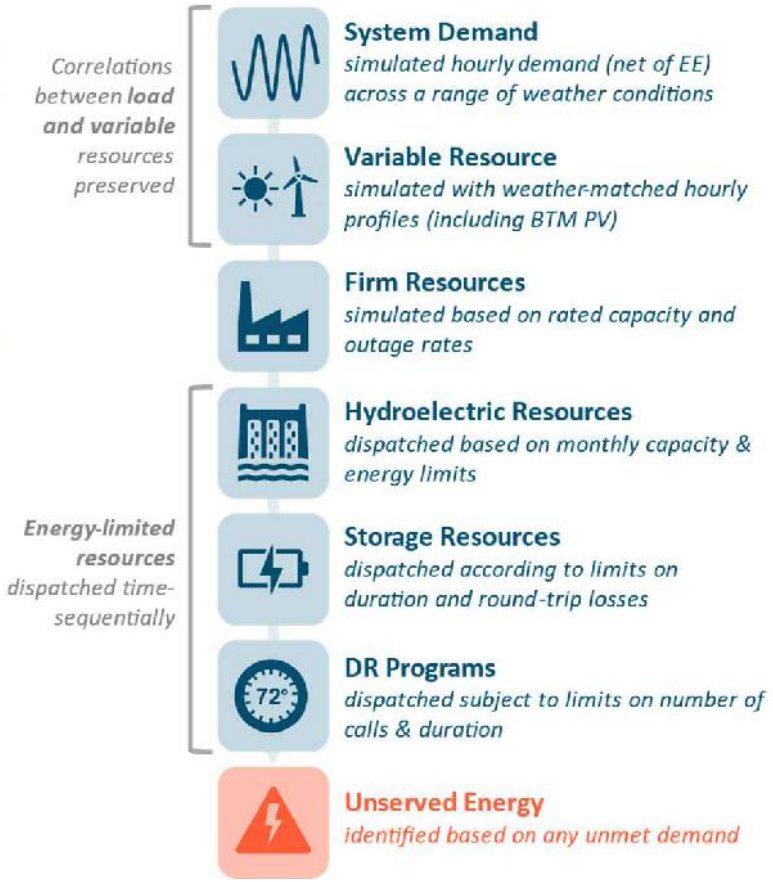
Appendix



Energy+Environmental Economics

RECAP: E3's Renewable Energy Capacity Planning model

- **RECAP uses a time-sequential simulation approach to assess the availability of supply to meet system needs on an hour-to-hour basis**
  - Simulation approach designed to focus on challenges resulting from increasing penetrations of variable & energy-limited resources
- **Each simulation analyzes conditions across hundreds or thousands of possible years using a Monte Carlo approach to capture year-to-year variations in:**
  - Underlying weather, load, wind & solar profiles
  - Power plant outage patterns
  - Energy-limited resource dispatch
- **Primary results include an array of indicators of system resource adequacy:**
  - Statistics of loss of load frequency, duration, and magnitude
  - Planning reserve margin requirement and ELCCs of different resources



Developing a rich library of hourly load & renewable profiles

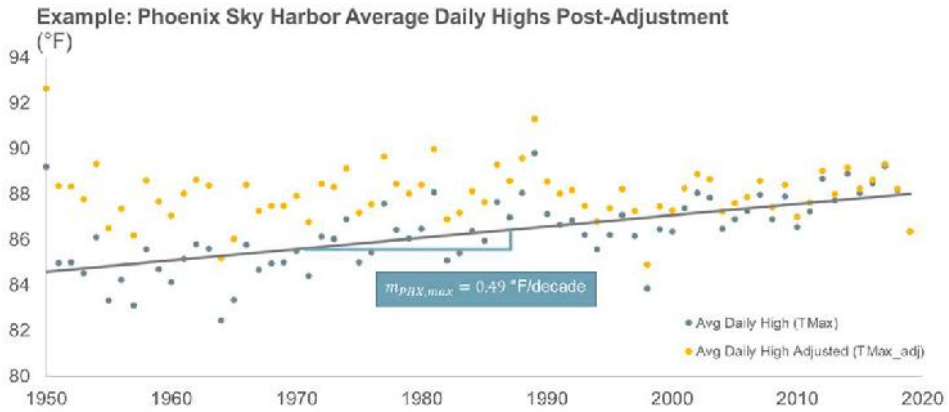
Profile	Primary Source(s)	Weather Conditions Captured	Notes
Loads	**WECC** Data request **NOAA** Historical Weather Data	2010 2019 1950 2019	• Neural network regression used to simulate hourly load patterns under broad range of weather conditions using recent historical load data (2010-2019) and long-term weather data (1950-2019) • Historical shape scaled to match future forecasts of regional energy demand • Shapes for load modifiers (e.g. transportation electrification) layered on top of neural network results
Wind	**NREL** WIND Toolkit	2007 2012	• Profiles for **existing wind resources** simulated based on plant locations, known characteristics (e.g. hub height & power curve) • Profiles for **future wind resources** simulated based on generic locations chosen by E3 with input from sponsors
Solar	**NREL** System Advisor Model	1998 2019	• Profiles for **existing utility-scale solar resources** simulated based on plant locations, known characteristics (tracking vs. tilt, inverter loading ratio) • Profiles for **future utility-scale solar resources** simulated based on generic locations and technology characteristics chosen by E3 with input from sponsors • Profiles for **behind-the-meter/distributed solar** simulated for each utility service area

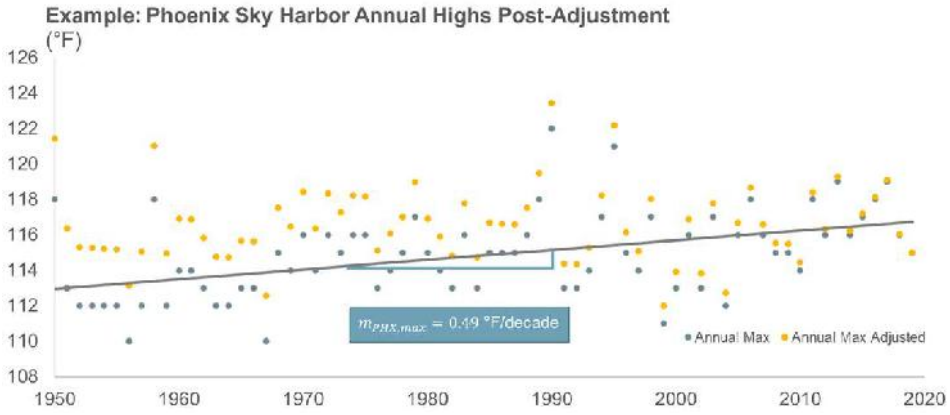
RECAP's endogenous day-matching algorithm extends shorter samples of wind and solar data to cover full historical period while preserving underlying correlations with load

Detrending historical weather data to account for impacts of climate change

- **Historical weather data is frequently used to simulate loads under a broad range of conditions for LOLP models – but the presence of a strong warming trend in historical data means that the past is not a predictor of the future**
  - Warming trend is particularly notable in Phoenix – the largest load center – where average and maximum temperatures have increased by 0.5F per decade since 1950
- **Load shapes for the Southwest region are simulated based on a "detrended" weather record, wherein the distribution of historical conditions is shifted upwards, resulting in:**
  - More extreme peak temperatures
  - More frequent high temperature extremes

	Average Temperature Change, 1950-2019 (Δ°F/decade)		
Weather Station	Annual Maximum Daily High Temp	Annual Average Daily High Temp	Annual Average Daily Low Temp
Albuquerque International Airport	+0.08	+0.08	+0.52
El Paso International Airport	+0.43	+0.31	+0.58
Phoenix Airport	+0.55	+0.49	+1.60
Tucson International Airport	+0.57	+0.52	+0.58





Additional detail on modeling assumptions available in final report

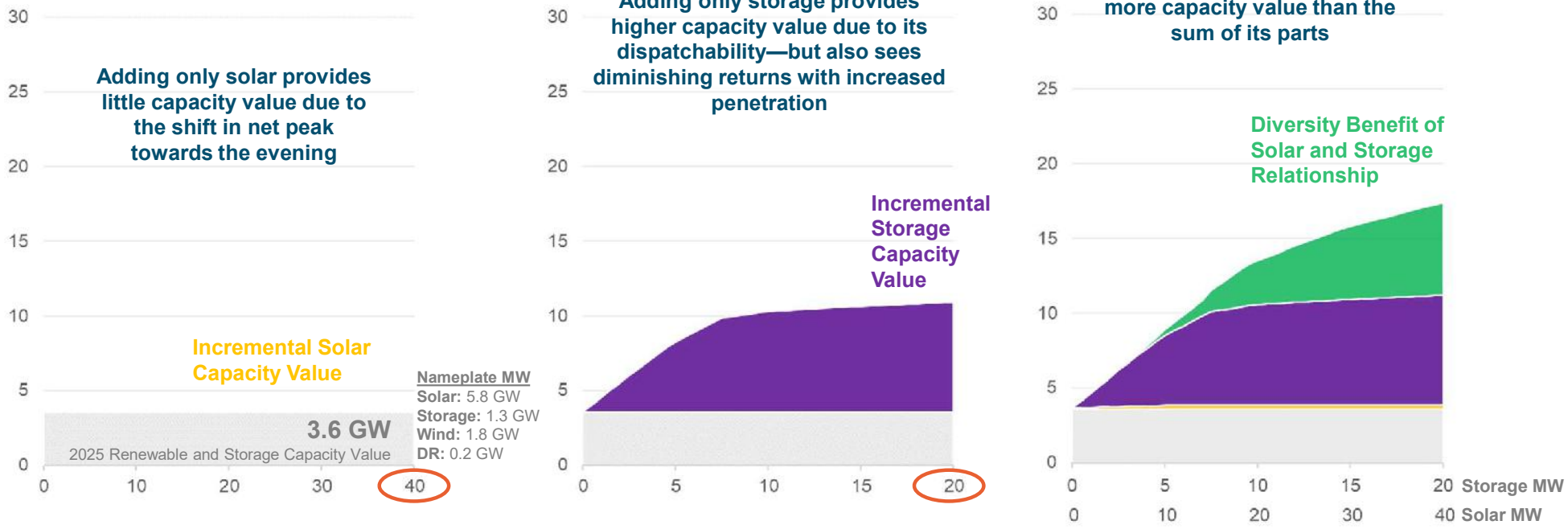
Module	Inputs Needed
System Demand	+ Annual energy demand (including energy efficiency impacts) + Annual 1-in-2 peak demand (including energy efficiency impacts) + Hourly profiles corresponding to a wide range of weather conditions (20+ years) + Minimum operating reserve requirements
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	+ Monthly capacity rating by resource + Forced outage rate by resource + Maintenance profile by resource
Variable Resources *(e.g. wind, solar)*	+ Installed capacity by resource + Hourly profiles for multiple years, ideally including multiple years of overlap with hourly load profile data
Hydroelectric Resources	+ Installed capacity by resource + Monthly/daily energy budgets across a range of plausible hydro conditions + Minimum output levels by month/day + Sustained peaking limitations by month/day
Storage Resources *(e.g. batteries, pumped storage)*	+ Installed capacity by resource + Duration by resource + Charging & discharging efficiency by resource + Paired variable resource (for hybrids) + Interconnection configuration & rating (for hybrids)
Demand Response Resources	+ Expected load impact by program + Limits on number of program calls (per year or per month) + Duration of calls

+ **Key data sources:**
  - **Utility IRPs**
  - ABB VelocitySuite
  - WECC historical load data
  - NREL SAM & Wind toolkit
  - EIA Form 860
  - EIA Electric Grid Monitor

The Southwest will rely on increasing levels of solar and storage to meet future reliability needs

Effective Capacity Contribution from Renewable and Storage Resources

Incremental to 2025 Existing and Committed Portfolio
(Effective GW)



Incremental Solar Additions
(Nameplate GW)

Incremental Storage Additions
(Nameplate GW)

Incremental Solar and Storage Additions
(Nameplate GW)

Desert Southwest loads & resources, 2025

	Existing & Planned Resources			IRP Portfolios		
	Installed Capacity (MW)	Effective Capacity (MW)	Effective Capacity (%)	Installed Capacity (MW)	Effective Capacity (MW)	Effective Capacity (%)
Nuclear	2,858	2,783	97%	2,858	2,783	97%
Coal	4,490	4,026	90%	4,490	4,026	90%
Natural Gas	15,659	14,711	94%	16,972	16,064	95%
Other	84	83	98%	84	83	98%
Geothermal	77	72	93%	77	72	93%
Hydro	1,437	1,137	79%	1,437	1,124	78%
Solar	5,778	1,531	27%	10,683	2,327	22%
Wind	1,781	696	39%	2,684	996	37%
Storage	1,299	1,167	90%	3,718	2,996	81%
DR	238	184	77%	618	468	76%
Total Supply	**33,701**	**26,388**		**43,621**	**30,938**	
Median Peak Demand		**26,741**			**26,741**	
Total Effective Capacity Need (+13% PRM)		30,178			30,178	
Net Capacity Surplus (Shortfall)		**(3,789)**			**+760**	

Desert Southwest loads & resources, 2033

	Existing & Planned Resources			IRP Portfolios		
	Installed Capacity (MW)	Effective Capacity (MW)	Effective Capacity (%)	Installed Capacity (MW)	Effective Capacity (MW)	Effective Capacity (%)
Nuclear	2,858	2,783	97%	2,858	2,783	97%
Coal	1,022	966	95%	1,022	966	95%
Natural Gas	15,029	14,281	95%	16,527	15,920	96%
Other	84	83	98%	84	83	98%
Geothermal	77	72	93%	577	537	93%
Hydro	1,437	1,101	77%	1,437	1,050	73%
Solar	5,758	1,416	25%	21,986	5,601	25%
Wind	1,781	594	33%	5,234	1,693	32%
Storage	1,299	1,174	90%	13,220	8,082	61%
DR	163	128	79%	1,047	465	44%
Total Supply	**29,508**	**22,597**		**63,992**	**37,180**	
Median Peak Demand		31,787			31,787	
Total Effective Capacity Need (+13% PRM)		**35,824**			**35,824**	
Net Capacity Surplus (Shortfall)		**(13,227)**			**+1,356**	

BREAK

PNM Talk to us.

SUPPLY RESILIENCE IN PLANNING FOR PNM

PNM RESILIENCY STUDY

Why PNM decided to commission the study:

- Questions from Public Advisory participants from the 2020 IRP process surrounding extreme weather analysis and durations of energy storage included in 2020 IRP portfolios.
- Increased Frequency of extreme weather events (2021 Texas event occurred two weeks after the 2020 IRP was filed)
- Gain better understanding of risks associated with decarbonization of the portfolio and the move from firm, dispatchable resource to variable and energy limited resources.

PNM Talk to us. PNM.com

SUPPLY RESILIENCE IN PLANNING FOR PNM

PHASE 1 STUDY GOALS AND DESIGN

- Phase 1 goals
  - Set up a framework to think about PNM supply resilience and performance under extreme events
  - Understand how different portfolios that all meet the traditional reliability standard of 0.2 LOLE perform during PNM-specific extreme events?
- Study design
  - Identify and parameterize extreme events that are most appropriate to PNM service territory
    - Winter (Ice storm) and Summer (Heat wave) extreme events were parameterized
  - Simulate scenarios of extreme events in Production Cost Simulation software (SERVM)
    - Within each group (winter & summer), on top of random forced outages, scenarios simulated increasing stress on PNM system
  - Gain insights into how pre-chosen PNM portfolios perform under increasing systemic stress levels in 2025
    - Tested portfolios were chosen on hypothetical Four Corners replacement alternatives
    - Measured metrics: *Fraction of simulations with lost load, Average MWh lost load, Peak MW shed, Duration of outage*

PNM Talk to us.

SUPPLY RESILIENCE IN PLANNING FOR PNM

HISTORIC EVENTS THAT SERVED AS INITIAL PARAMETERIZATION OF SCENARIOS

- February 2011 Southwest Cold Weather Event
- August 2020 Western Heat Storm
- February 2021 Winter Storm Uri

PNM Talk to us.

SUPPLY RESILIENCE IN PLANNING FOR PNM

PNM EXISTING SYSTEM AND EXPANSION PORTFOLIOS

Common resources do not vary across scenarios

Resource	Common Resources (MW)	Scenario-Specific Resources (MW)				
		PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)
Palo Verde	288	-	-	-	-	-
DR	48					
Geothermal	11					
Four Corners	-	+200	-	-	-	-
Gas	987	-	-	+39*	+39*	+152*
Wind	607	-	-	+180	-	-
Solar	1523	-	+96	-	+96	-
Batteries (4hr)	490	-	+108	+90	+108	-
Batteries (2hr)	100	-	+48	-	-	-

**All new gas resources are assumed to be aeroderivative turbines with winterization*

All tested portfolios calibrated to meet the same reliability standard (0.2 LOLE in summer)

The portfolios designs were based upon the 2020 IRP TN and NNC modeling pathways updated with the additional changes to the system filed for and approved in Case No. 21-00215-UT (PVNGS)

PNM Talk to us.

SUPPLY RESILIENCE IN PLANNING FOR PNM

USEFUL MATERIALS

As we go through the resiliency study and especially when we arrive at the slides presented charts and table of the results, the audience may find it helpful to separately have a copy of the following slides for reference:

Slide 48: PNM Existing System and Expansion Portfolios (2025)

Slide 55: Table of Extreme Winter Event Scenario and Sensitivity descriptions

Slide 56: Table of Extreme Summer Event Scenario and Sensitivity descriptions

PNM Talk to us.

Supply Resilience in Planning for PNM:

A study considering extreme weather events in supply planning

May 25, 2022



Energy+Environmental Economics

ASTRAPÉ CONSULTING
innovation in electric system planning

Resilience is a part of Reliability

- **"Grid reliability" encompasses a number of utility planning functions**
- **Many of these function have well-established methods and standards:**
  - Resource adequacy
  - Transmission stability
  - Distribution reliability
  - Operational reliability & flexibility
- **"Resilience" is an emerging concern but historically has not been clearly defined, and there are no formal standards for what qualifies as a "resilient" grid**
  - Should encompass all parts of the system: G, T, and D
- **This study focuses on exploring the resilience of supply and its relationship to resource adequacy**



Distribution System Reliability

Ensure distribution systems are planned to enable delivery of electricity to loads even under severe contingency conditions



Transmission System Reliability

Ensure transmission systems can deliver electricity from generators to distribution systems under steady state and dynamic contingency conditions



Resource Adequacy

Ensure sufficient generation resources are available to meet load with an acceptable level of reliability across a broad range of load conditions while accounting for generator outages, weather impacts on loads & resources, and other constraints on generator availability



Operational Reliability

Maintain system reliability in real-time operations by balancing loads with generation while maintaining sufficient operating reserves to meet flexibility needs and respond to contingencies



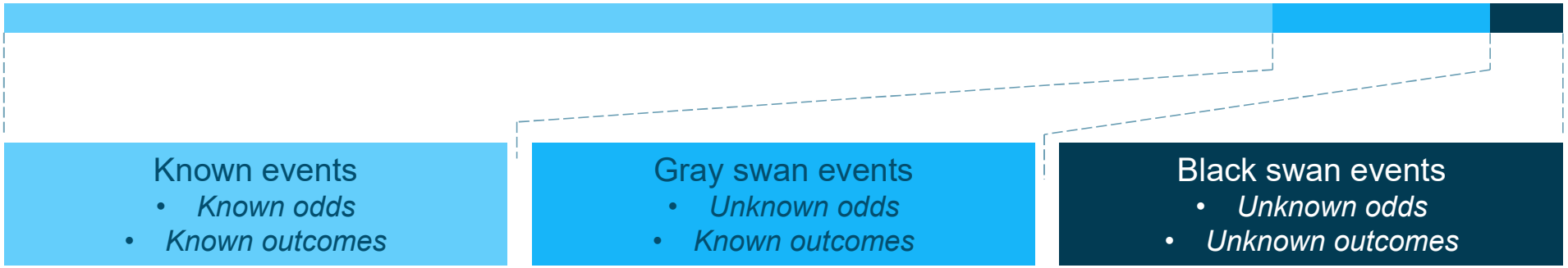
Resilience

Anticipate, respond to, and recover from extreme unexpected events and systemic shocks to any and all parts of the electricity system, including extreme weather events and cyber threats

Reliability risks fall into three categories

Increasing severity of events →

Decreasing number of events in each category →



Known events	Gray swan events	Black swan events
• *Known odds* • *Known outcomes*	• *Unknown odds* • *Known outcomes*	• *Unknown odds* • *Unknown outcomes*
+ **Have enough historical data to assign probabilities with reasonable confidence**	+ **Have some historical experience, but not enough to assign probabilities** + **These are projected to increase in the future**	+ **Cannot reasonably estimate probabilities or nature of events**
Focus of resource adequacy analysis	**Focus of resilience analysis**	

Supply Resilience vs. Resource Adequacy

+ **Traditional probabilistic analysis framework for resource adequacy is not suitable for resilience analysis**
  - ***The probabilities and outcomes of potential resilience events are not well known***
+ **A deterministic, risk management framework based on worse case study scenarios is better suited to address resilience planning questions**
  - ***Case studies allow utilities to understand the impact of potential extreme events and explore mitigation measures when making planning decisions***

Resource Adequacy	Supply Resilience
Issues that can be captured in LOLP modeling	**Issues that require a deterministic case study framework**
Potential load/renewable events based on historical conditions	Extreme load/renewable events; specific ***worse case scenarios***
Randomly simulated outages	***Correlated outages*** due to ***external or common mode events*** beyond electricity (e.g. gas fuel supply during a polar vortex, natural disasters, etc.)
The frequency, magnitude, and duration of expected loss of load events	The ***acceptability of and response to the loss of load events*** modeled

Key risk factors under extreme weather events

+ **Extreme weather could bring challenges to system supply through a number of factors**
  - Potential threats include load spikes, fuel supply disruptions, thermal outages, renewable variability, battery contingencies, import constraints, etc.
+ **PNM developed case studies surrounding these risk factors to examine the impacts of potential winter and summer weather events with different degrees of severity**



Load Spikes



Thermal Outages and Fuel Supply Issues



Renewable Variability



Battery Performance



Market Support

Extreme Winter Event (Ice Storm) Sensitivities

Winter event scenarios focus on the impacts of large-scale thermal outages and loss of market support under ice storm

Ice storm Sensitivity #	Sensitivity Name	Description	Purpose
1	Base	Base cold snap extreme weather event	Provide baseline for each portfolio based on a baseline extreme weather event
2	Island	PNM is simulated as an island (no neighbors, imports, or exports)	Test the effects of not having access to neighboring markets
3	Island, Conservative Battery Operation	Island sensitivity, but batteries are operated as capacity only resources (no energy arbitrage)	Test the effects of changing battery dispatch signal from price to reliability
4	Localized Plant Outages	2021 Ice storm ERCOT level of forced outages simulated for PNM; PNM is connected to neighbors	Test the effects of cold weather-correlated forced outages at PNM plants (i.e., fuel disruption, cold weather equipment failures, etc.)
5	Regional Plant Outages	PNM and neighboring entities experience ERCOT level of outages	Test the effects of geographically wide cold event that leads to cold weather-correlated forced outages across the region (i.e., fuel disruption, cold weather equipment failures, etc.)
6	Localized Plant Outages, Island	ERCOT level of forced outages simulated for PNM; No support available from neighboring markets	Test the effects of geographically wide cold event that leads to cold weather-correlated forced outages at PNM plants (i.e., fuel disruption, cold weather equipment failures, etc.) and not having access to neighboring markets
7	Island, PNM South Generation Out	PNM loses access to south region generation for the week; No support available from neighboring markets	Test the effects of geographically wide cold event that leads to cold weather-correlated forced outages at PNM plants (simulating a major transmission fault, or fuel supply issues), with a loss of 500 MW of generation and not having access to neighboring markets

Extreme Summer Event (Heat Wave) Sensitivities

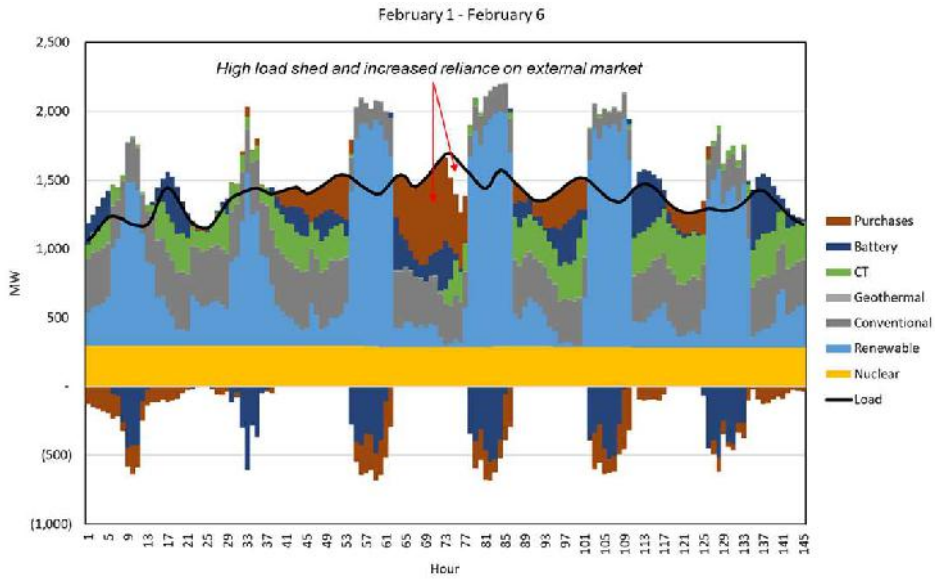
Summer event scenarios focus on the impacts of load spikes and storage contingencies under heat wave

Heat Wave Sensitivity #	Sensitivity Name	Description	Purpose
1	Base	Base case heat wave extreme weather event	Provide baseline for each portfolio based on a baseline extreme weather event
2	Island	PNM is simulated as an island (no neighbors, imports, or exports)	Test the effects of not having access to neighboring markets
3	1 in 20	PNM's peak load is consistent with a 1 in 20 load forecast	Test the effects of under forecasting peak demand (greater peak demands due to climate change)
4	G1	Contingency occurs to the largest battery facility for the week (150 MW)	Test the effects of overestimating the availability of BESS / the BESS Forced Outage occurs at the worst time
5	G2	Contingencies occur to two largest battery facilities for the week (150 MW + 150 MW = 300 MW)	Test the effects of overestimating the availability of BESS / the BESS Forced Outage occurs at the worst time
6	G2, 1 in 20	Sensitivity G2 + Sensitivity 1 in 20	Test the effects of overestimating the availability of BESS / the BESS Forced Outage occurs at the worst time combined with under forecasting peak demand (greater peak demands due to climate change)

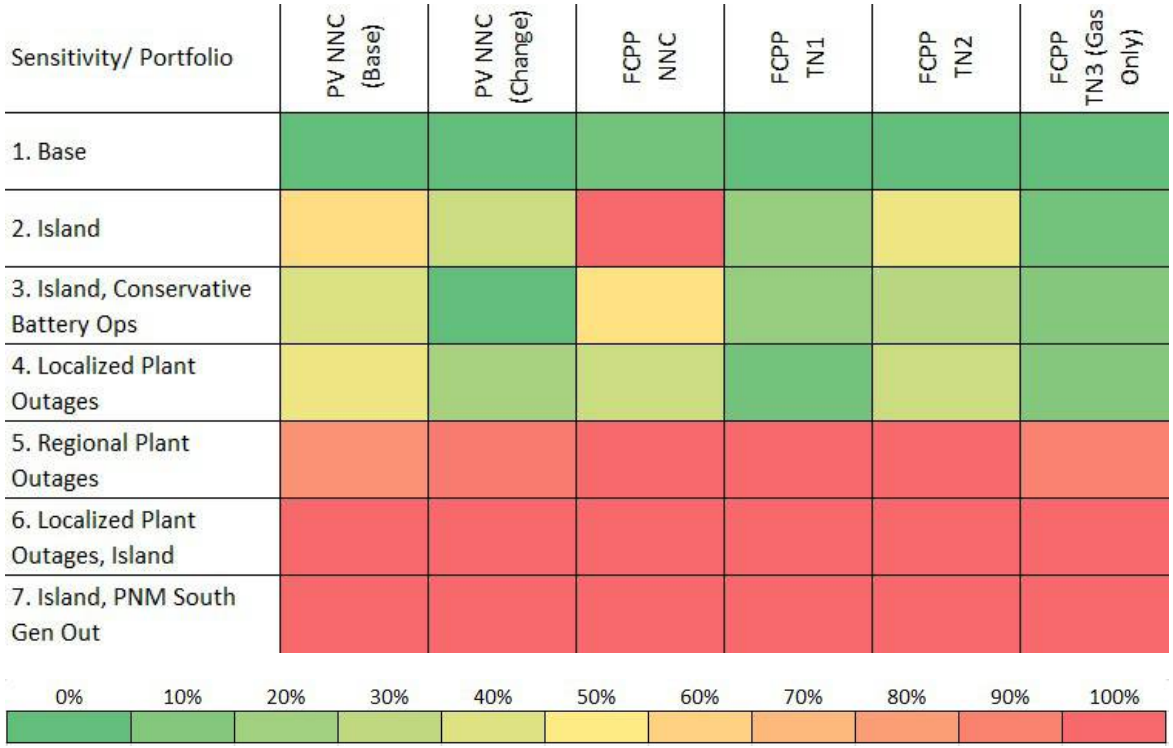
Study Framework

- **PNM used SERVM, the production cost simulation and loss of load probability model that was used to study resource adequacy in its 2020 IRP, to stress test the performance of different portfolios under different resilience sensitivities for a selected one-week period**
- **Key assumptions are varied in the model based on the characterization of the sensitivities**
- **PNM examined portfolio performance in multiple dimensions**
  - The probability of shedding load; Expected Value of MWh shed (MWh); Expected Value of worst hour of shedding (MW); Number of unique hours where loss of load was observed to occur (Hours)

Simulation Result for the Southwest Outages Scenario with FCPP NNC Portfolio



Probability of load shed during winter extreme event



Case 1 (Base) vs Case 2 (Island):

Reliance on external market helps PNM reduce outages

Case 2 (Island) vs Case 3 (Island with Conservative Battery Ops):

Changing battery operations when markets tighten reduces some risk of load shed events

Case 1 (Base) vs Case 4 (PNM Outages):

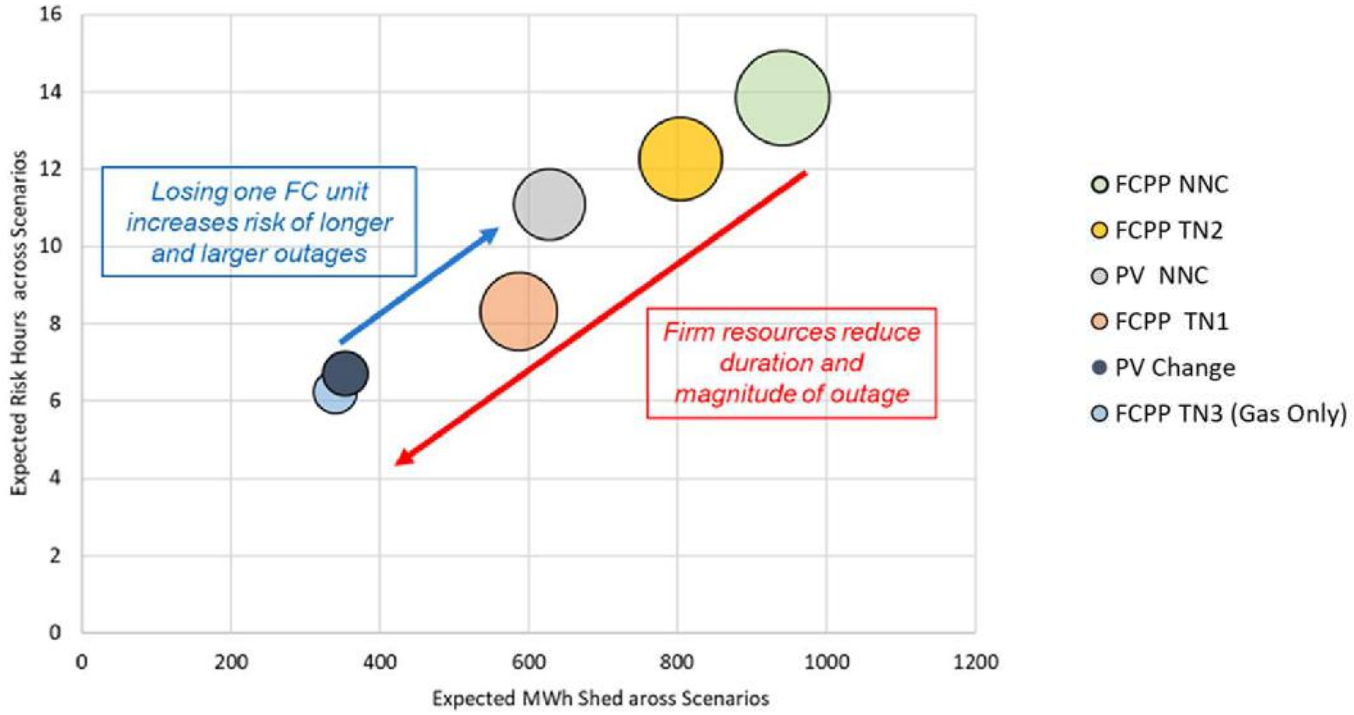
Winterization helps improve resilience of PNM's portfolio

Case 1 (Base) vs Cases 5,6 & 7:

A region-wide ice storm almost certainly leads to PNM outages

Incremental gas is assumed to be winterized. 'PV NNC' is existing portfolio with Four Corners 4 out on maintenance. 'PV Change' is Four Corners 4 and 5 available with 20% EFOR.

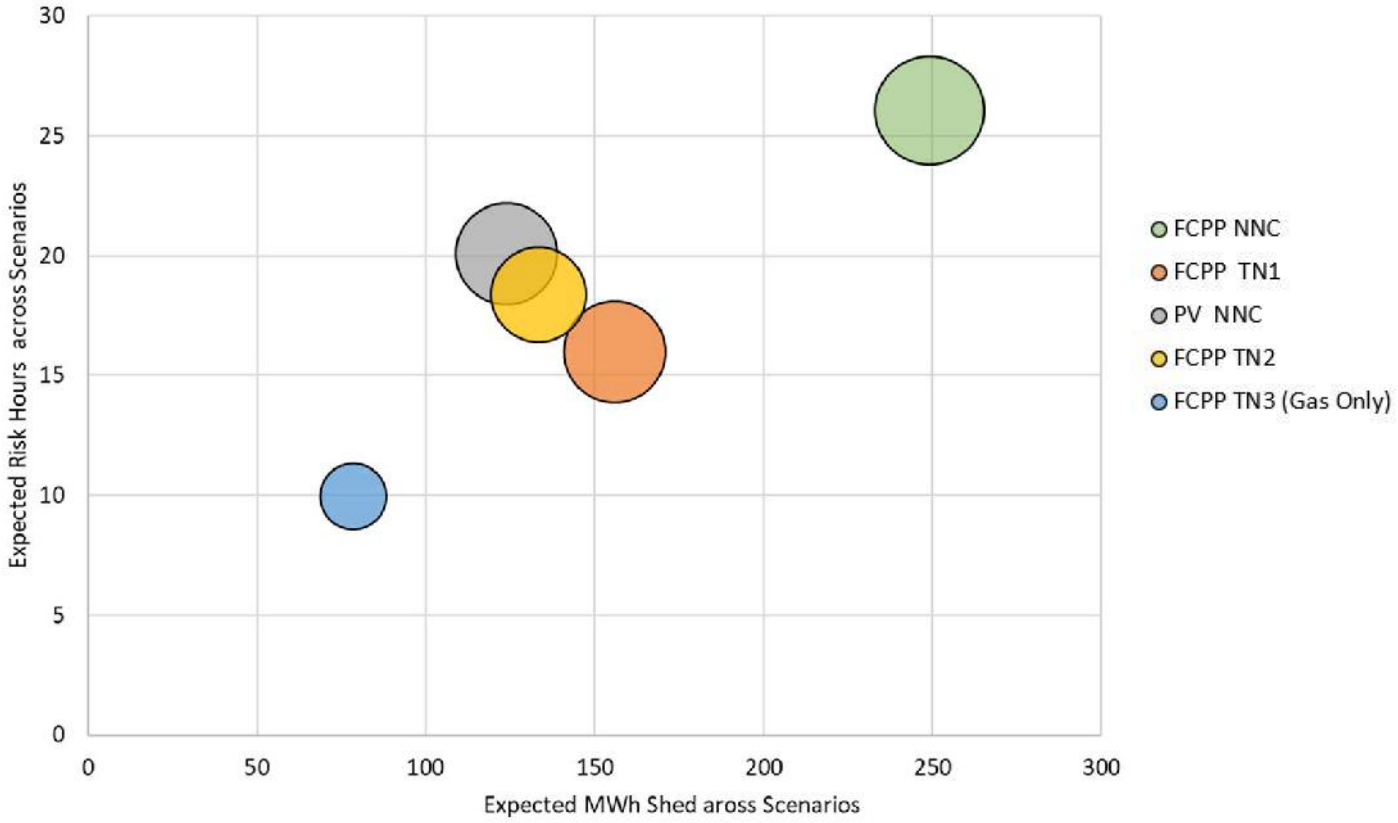
Winter extreme event simulation results*



** Scenario metrics were weighted using an inversely proportional scale. Bubbles sized according to expected MW shed in most binding hour*

Incremental gas is assumed to be winterized. 'PV NNC' is existing portfolio with Four Corners 4 out on maintenance. 'PV Change' is Four Corners 4 and 5 available with 20% EFOR.

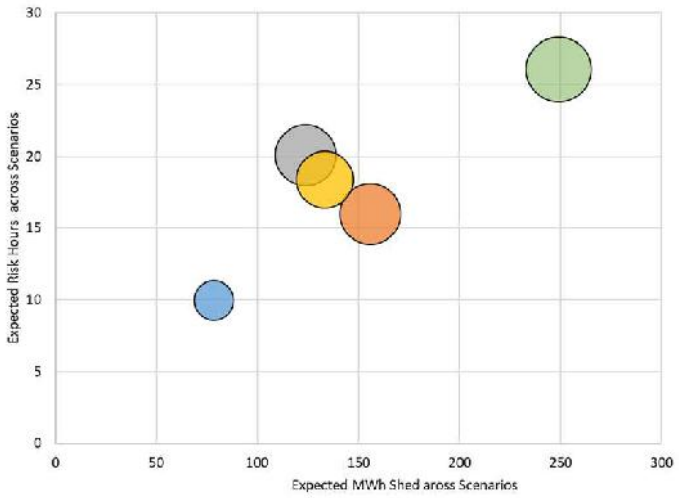
Summer extreme event simulation results are similar to winter



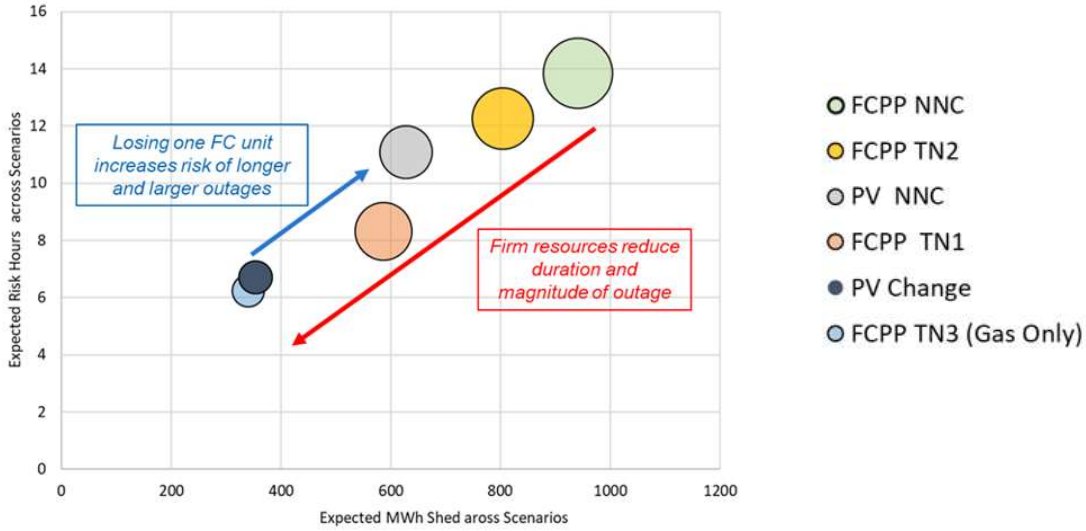
** Scenario metrics were weighted using an inversely proportional scale. Bubbles sized according to expected MW shed in most binding hour*

Design of a deeply decarbonized portfolio that meets the reliability characteristics of a traditional system

Summer Extreme Event



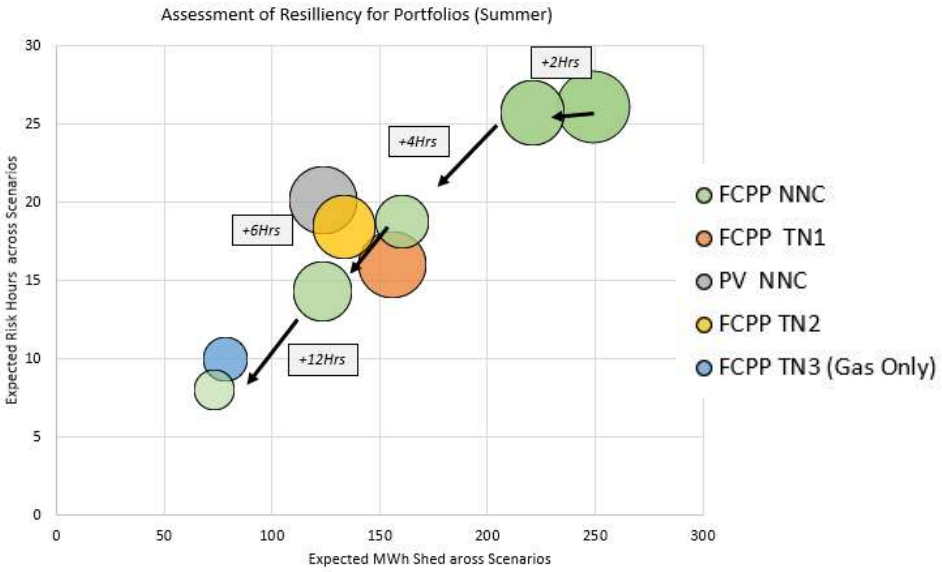
Winter Extreme Event

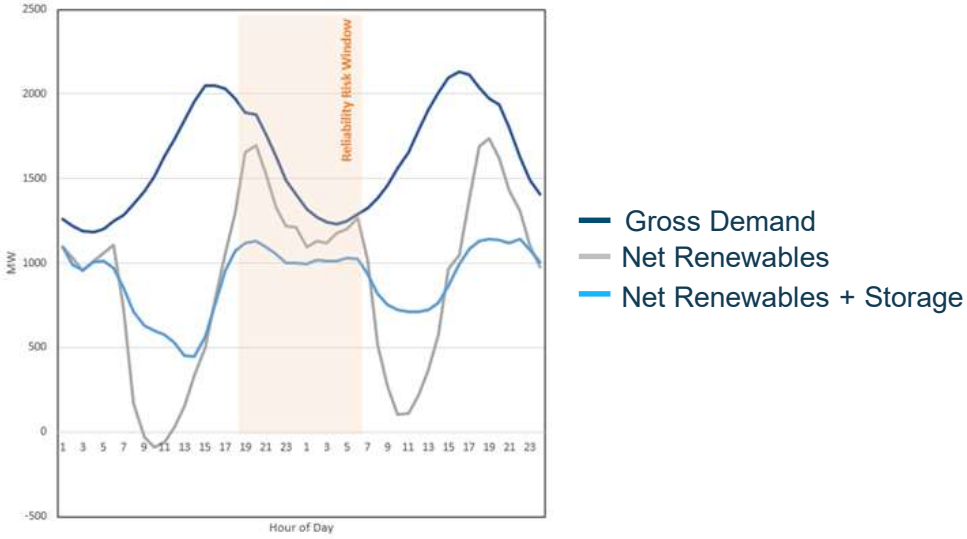


** Scenario metrics were weighted using an inversely proportional scale. Bubbles sized according to expected MW shed in most binding hour*

Incremental gas is assumed to be winterized. 'PV NNC' is existing portfolio with Four Corners 4 out on maintenance. 'PV Change' is Four Corners 4 and 5 available with 20% EFOR.

Design of a deeply decarbonized portfolio that meets the reliability characteristics of a traditional system





Takeaways

+ **Portfolios planned with a reliability standard in mind vary in performance during extreme events**
+ **Stress testing candidate portfolios for resilience is important to understand differences in their performance**
+ **Winterization helps reduce outages and firm up generation reducing the severity of extreme event impacts**
+ **During ice storms, broader southwest dynamics will have significant impact on PNM's ability to avoid outages under extreme events**
  - PNM can weather localized ice storms by relying on external markets, but region-wide events almost certainly lead to outages.
  - Market support is limited in summer and PNM's system can avoid outages during a heat wave unless load reaches 1-in-20 levels or significant level of generation is forced out.
+ **PNM should continue to monitor risk profile in winter season. Resource accreditation should continue to match the risk profile PNM is presented with**
+ **As PNM increases its storage portfolio, its operational limits and utilization should be understood and considered in resource adequacy modeling**

Other E3 studies show similar results

+ **Omaha Public Power District (OPPD) 2021 Pathways to Decarbonization Study (https://www.oppdcommunityconnect.com/energy-portfolio)**
  - E3 performed resiliency tests to a 2050 portfolio developed for OPPD with a net-zero emissions target
+ **Resource Adequacy in the Desert Southwest (https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf**
  - E3 performed deterministic worse-than normal scenario studies to understand the impacts of potential resiliency events in the Desert Southwest

Takeaways

- ❑ **Resilience events add stress to a system planned with reliability target in mind. Stress testing system performance using deterministic case studies helps evaluate the impact of potential risks and identify mitigation solutions**
- ❑ **Firm resources provide critical support during times with sustained low renewable generation**
- ❑ **Winterization of generation resources and fuel supply network helps mitigate negative impacts from catastrophic winter events**
- ❑ **Market support plays an important role in maintaining reliability during localized extreme events**

Thank You

Questions?

Nick Schlag, nick@ethree.com
Saamrat Kasina, saamrat@ethree.com
Nick Wintermantel, nwintermantel@astrape.com
Chase Winkler, cwinkler@astrape.com



Energy+Environmental Economics

ASTRAPÉ CONSULTING
innovation in electric system planning

Appendix



Energy+Environmental Economics

A TRAPÉ CONSULTING
innovation in electric system planning

Extreme Winter Event (Ice Storm) Scenarios

Winter event scenarios focus on the impacts of large-scale thermal outages and loss of market support under ice storm

	Load	Thermal Outages	Level of Market Support	Battery Storage
Base winter event scenario	**Projected 2025 demand** *(under Feb 2011 weather conditions)*	**Randomly simulated**	**Normal**	**Economic arbitrage**
PNM as an Island	Same as base	Same as base	**No market support**	Same as base
PNM as an Island with conservative battery operations	Same as base	Same as base	**No market support**	**Storage operation prioritizes reliability support**
PNM with ERCOT-esque gas outages	Same as base	**Weather-related gas plant outages simulated for PNM benchmarking to 2021 ERCOT record**	Same as base	Same as base
PNM and neighbors with ERCOT-esque gas outages	Same as base	**Weather-related gas plant outages simulated for PNM and neighboring markets benchmarking to 2021 ERCOT record**	**Reduced market support due to gas outages across the region**	Same as base
PNM as an island with ERCOT-esque gas outages	Same as base	**Weather-related gas plant outages simulated for PNM benchmarking to 2021 ERCOT record**	**No market support**	Same as base
PNM as an island with south region generation offline	Same as base	**PNM loses access to south region generation**	**No market support**	Same as base

Extreme Summer Event (Heat Wave) Scenarios

Summer event scenarios focus on the impacts of load spikes and storage contingencies under heat wave

	Load	Thermal Outages	Level of Market Support	Battery Storage
Base summer event scenario	**Projected 2025 demand** *(under Aug 2020 weather conditions)*	**Randomly simulated**	**Capped at 50 MW during net peak periods**	**No major battery contingencies**
1 in 20 peak load	**1 in 20 peak demand**	Same as base	Same as base	Same as base
G1 battery event	Same as base	Same as base	Same as base	**Loss of largest battery facility**
G2 battery event	Same as base	Same as base	Same as base	**Loss of 2 largest storage facilities**
1 in 20 peak load and G2 battery event	**1 in 20 peak demand**	Same as base	Same as base	**Loss of 2 largest storage facilities**

Summer scenario results

Sensitives

- **Sensitivities were performed for the following scenarios:**
  - 1 in 20 peak load conditions
  - G1 battery event (loss of largest storage facility)
  - G2 battery event (loss of 2 largest storage facilities)
  - G2 and 1 in20 (1 in 20 load conditions, and loss of 2 largest storage facilities)
- **Sensitivity analysis assumes PNM as an Island**
- **The following metrics are reported**
  - Expected Value of MWh shed *(MWh)*
  - The Expected Value of worst hour of shedding *(MW)*
  - The number of unique hours where loss of load was observed to occur *(Hours)*

All Portfolios were solved to 0.2 LOLE given the PNM representation in SERVM (consistent with IRP and PVNGS filings)

Portfolio Mixes Evaluated

	Resource	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)
Existing	Four Corners 4	Available, 20% EFOR	OFF	OFF	OFF	OFF
	Four Corners 5	Available, 20% EFOR	OFF	OFF	OFF	OFF
Incremental	Aero			39 MW	39 MW	152 MW
	Wind			180 MW		
	Solar		96 MW		96 MW	
	4 Hr Battery		108 MW	90 MW	108 MW	
	2 Hr Battery		48 MW (Paired)			

Sensitivity Analysis (Average MWh lost)

Scenario	MWh				
	PV NNC	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)
Base	~0	*Not Assessed*			
Island	~0	*Not Assessed*			
1 in 20	74	162	45	50	37
G1	81	196	141	82	18
G2	198	408	316	298	210
G2 + 1 in 20	720	989	786	804	540

Sensitivity Analysis (MW)

Scenario	MW				
	PV NNC	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)
Base	~0	*Not Assessed*			
Island	~0	*Not Assessed*			
1 in 20	29	28	13	27	13
G1	23	31	34	18	14
G2	64	63	76	70	54
G2 + 1 in 20	151	160	164	137	118

Sensitivity Analysis (Hours)

Scenario	Hours				
	PV NNC	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)
Base	~0	*Not Assessed*			
Island	~0	*Not Assessed*			
1 in 20	19	20	9	12	9
G1	19	24	17	21	6
G2	21	41	28	27	18
G2 + 1 in 20	37	49	31	26	25

Winter scenario results

Sensitives

- **Sensitivities were performed for the following scenarios:**
  - PNM as an Island
  - PNM as an Island with conservative battery operations
  - PNM with ERCOT-esque gas outages
  - PNM and neighbors with ERCOT-esque gas outages
  - PNM as an island with ERCOT-esque gas outages
  - PNM as an island with south region generation offline
- **The following metrics are reported**
  - Expected Value of MWh shed *(MWh)*
  - The Expected Value of worst hour of shedding *(MW)*
  - The number of unique hours where loss of load was observed to occur *(Hours)*

The Winter LOLE of each portfolios is unknown (i.e., if the base case was set to 0.2 LOLE occurring in the winter, the alternative portfolios may be more or less reliability than 0.2)

Portfolio Mixes Evaluated

Portfolios are likely not LOLE equivalent from a winter perspective
- FC4 offline in PV NNC
- Replacement portfolios have unknown Winter ELCCs
  - Storage ELCCs likely lower than summer ELCC
  - Wind ELCC likely higher than summer ELCC

	Resource	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)	PV NNC (Change)
Existing	Four Corners 4	On Maintenance	OFF	OFF	OFF	OFF	Available, 20% EFOR
	Four Corners 5	Available, 20% EFOR	OFF	OFF	OFF	OFF	Available, 20% EFOR
Incremental	Aero			39 MW	39 MW	152 MW	
	Wind			180 MW			
	Solar		96 MW		96 MW		
	4 Hr Battery		108 MW	90 MW	108 MW		
	2 Hr Battery		48 MW (Paired)				

Load Shed Summary

Scenario	Study Assumptions			MWh					
	PNM as an Island?	Cold Weather Outages	Battery Economic Arbitrage?	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)	PV NNC (Change)
Base	No	No	Yes	-	6	-	-	-	-
Island	Yes	No	Yes	212	453	89	149	6	141
Island, Conservative Battery Ops	Yes	No	No	113	275	26	103	5	0
PNM outages	No	Yes	Yes	14	4	~0	1	1	4
Southwest Outages	No	Yes	Yes	476	763	594	681	445	257
Outages + Island	Yes	Yes	Yes	4,345	6,227	4,700	5,156	3,273	3,218
Island + PNM South Gen Out	Yes	Yes	Yes	22,094	25,290	17,228	22,988	15,385	14,480

Study Assumptions detrimental to reliability marked in red

Load Shed Summary

Scenario	Study Assumptions			Peak					
	PNM as an Island?	Cold Weather Outages	Battery Economic Arbitrage?	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)	PV NNC (Change)
Base	No	No	Yes	-	28	-	-	-	
Island	Yes	No	Yes	523	474	495	431	72	513
Island, Conservative Battery Ops	Yes	No	No	347	490	287	339	66	0
PNM outages	No	Yes	Yes	136	33	1	16	20	42
Southwest Outages	No	Yes	Yes	897	708	721	801	541	121
Outages + Island	Yes	Yes	Yes	968	1,186	1,170	1,192	1,019	899
Island + PNM South Gen Out	Yes	Yes	Yes	962	1,047	1,003	1,040	919	960

Study Assumptions detrimental to reliability marked in red

Load Shed Summary

Scenario	Study Assumptions			Hours					
	PNM as an Island?	Cold Weather Outages	Battery Economic Arbitrage?	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)	PV NNC (Change)
Base	No	No	Yes	-	2	-	-	-	-
Island	Yes	No	Yes	13	14	13	8	2	6
Island, Conservative Battery Ops	Yes	No	No	6	5	3	5	1	0
PNM outages	No	Yes	Yes	4	5	1	4	3	3
Southwest Outages	No	Yes	Yes	9	6	7	7	8	7
Outages + Island	Yes	Yes	Yes	33	35	31	32	24	23
Island + PNM South Gen Out	Yes	Yes	Yes	88	86	78	77	60	79

Study Assumptions detrimental to reliability marked in red

Load Shed Summary

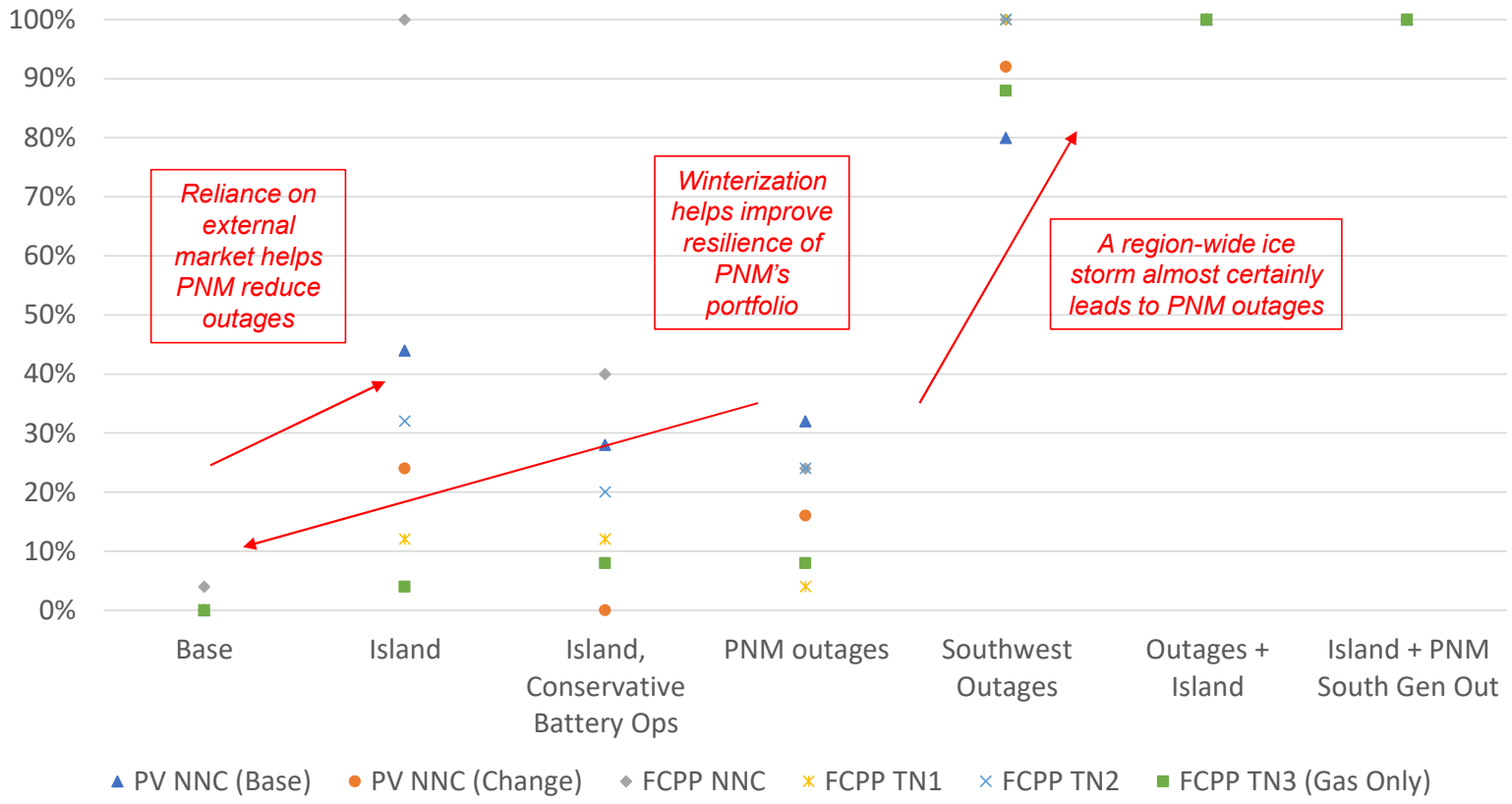
Scenario	Study Assumptions			% of Iterations with Load Shed					
	PNM as an Island?	Cold Weather Outages	Battery Economic Arbitrage?	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)	PV NNC (Change)
Base	No	No	Yes	0%	4%	0%	0%	0%	0%
Island	Yes	No	Yes	44%	100%	12%	32%	4%	24%
Island, Conservative Battery Ops	Yes	No	No	28%	40%	12%	20%	8%	0%
PNM outages	No	Yes	Yes	32%	24%	4%	24%	8%	16%
Southwest Outages	No	Yes	Yes	80%	100%	100%	100%	88%	92%
Outages + Island	Yes	Yes	Yes	100%	100%	100%	100%	100%	100%
Island + PNM South Gen Out	Yes	Yes	Yes	100%	100%	100%	100%	100%	100%

Study Assumptions detrimental to reliability marked in red

Portfolio mixes tested

	Resource	PV NNC (Base)	FCPP NNC	FCPP TN1	FCPP TN2	FCPP TN3 (Gas Only)
Existing	Four Corners 4	Available, 20% EFOR	OFF	OFF	OFF	OFF
	Four Corners 5	Available, 20% EFOR	OFF	OFF	OFF	OFF
Incremental	Aero			39 MW	39 MW	152 MW
	Wind			180 MW		
	Solar		96 MW		96 MW	
	4 Hr Battery		108 MW	90 MW	108 MW	
	2 Hr Battery		48 MW (Paired)			

Probability of load shed during winter extreme event



Incremental gas is assumed to be winterized. 'PV NNC' is existing portfolio with Four Corners 4 out on maintenance. 'PV Change' is Four Corners 4 and 5 available with 20% EFOR.

SUPPLY RESILIENCE IN PLANNING FOR PNM

PNM RESOURCE ADEQUACY GOING FORWARD AND KEY QUESTIONS TO ANSWER (SUBSEQUENT MEETINGS)

Traditional systems designed around a LOLE standard (such as 1 day in 10 years) have similar performance if a loss of load event occurred (traditional portfolios did not vary much in the severity of event – EUE)

This study shows that focusing solely on LOLE can lead to portfolios that do vary significantly in the severity of an event if an event occurs.

1. Moving forward, should portfolios should be designed to meet both a LOLE and an EUE requirement (Essentially should a decarbonized system should focus on providing the same attributes as a traditional system, just without carbon emissions)?

2. Along with bringing EUE into portfolios evaluations along with LOLE, should portfolios be further stress tested to gauge performance under adverse conditions as done in this study?

3. Finally, should the value of loss of load (which conceptually increase as a function of the duration of loss of load) be compared to the perceived cost of GHG?

PNM Talk to us.

SUPPLY RESILIENCE IN PLANNING FOR PNM

RESILIENCY STUDY PHASE II SCOPE OF WORK IDEAS, QUESTIONS TO ANSWER, ETC.

Given the limited data of actual events, what other ways do we have to synthesize extreme weather data?

How can we establish a (or what is a reasonable) baseline for portfolio metrics such as EUE?

What alternatives to we have for improving resiliency of the system aside from only utility scale resources?

What is the most cost-effective way of improving both summer and winter resilience?

What would be necessary to assess transmission within this current framework?

Is storage duration critical, or is storage volume more important and what is the cost tradeoff?

PNM Talk to us.

2023 IRP PUBLIC ADVISORY PROCESS

WE WOULD LIKE TO HEAR FROM YOU

We did not receive any feedback to these questions posted during the last public meeting:

1. What did we do well in the last (2020) IRP and where can we improve?
2. Any additional ideas for technical discussions?
3. What is the proper way to balance reliability, customer cost and accelerating the transition to clean energy?
4. How can we be more collaborative throughout the process with our public stakeholders?

We would also like to hear your ideas on the How we incorporate key takeaways and lessons learned from the Resiliency Study Phase I into the 2023 IRP so we can begin these discussions at our June 8, 2022 meeting.

We would also like to hear your ideas on the Resiliency Study Phase II Scope of Work / Questions to Answer.

2023 IRP PUBLIC ADVISORY NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: June 8, 2022

Topic: Public Advisory Technical Session #1

Start Time: 9:00 AM

Location: Virtual

One of our goals for this IRP cycle is to increase the level of public input and participation in the IRP development process. Most participants for the first two meetings attending virtually. Consequently, we have decided to make the first technical session a fully virtual meeting hoping that a single delivery format will foster greater participation and collaboration. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person). If there is little interest to resume in person meetings in the near term, we will revisit the interest for in person meetings again later in the process when we begin to present the results of finalized forecasts, modeling runs, etc.

PNM Talk to us.

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by June 1, 2022.

PNM Talk to us.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

PNM Talk to us.

Thank you



PNM 2023-2042 IRP: Modeling for Reliability, Resource Adequacy and Resiliency

TECHNICAL SESSION #1 **JUNE 8, 2022**



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

03 

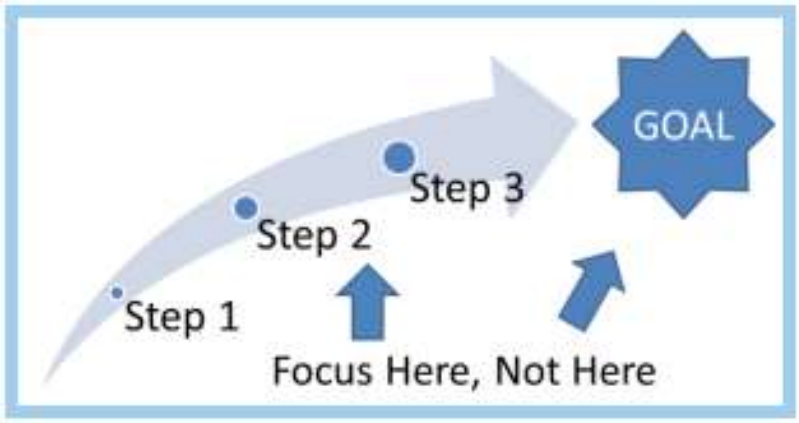
- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

TECHNICAL SESSION

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

TENTATIVE MEETING OUTLINE

- Welcome and Introductions
- Any follow up questions from the previous presentation now that stakeholders have had some additional time with the presentation materials or other questions / updates of topics of interest
  - This could include more information on the presentations to clarify the materials
  - A deeper dive into the studies and how they were performed
  - Etc.
- A quick review of the results and key findings of presentations
- A quick review of the modeling framework utilized in the 2020 IRP
- Open forum for any stakeholder discussion / presentation / examples / kickoff into thoughts on how we incorporate key findings / lessons learned from these studies into the 2023 IRP Development (Some ideas below but not limited to just these ideas, again PNM wants to be one participant of this process, but we want the process to be stakeholder driven/workgroup/workshop like – not a PNM presentation)
  - Different Risk Metrics, what they are, what the capture, how to use them in planning, etc.
  - ELCC Study for the 2023 IRP, methods of analysis, ways to capture synergies of resources, etc.
  - ELCC by risk metrics
  - Setup of the SERVM model for calculating ELCC and how to use the results within EnCompass
  - Baselines for different risk metrics
  - Other questions on Slides 84 and 85 of the 5/25 meeting slides
- Next steps and Near-Term Schedule

MAY 25TH PRESENTATION FOLLOW UP

Are there…

- Any follow up questions to the materials presented in the last meeting?
- Any additional clarifications that would help before diving into the technical discussion?
- Any additional details about the studies, how they were performed, data used, etc. that would be useful to better inform the technical discussions?

PNM Talk to us.

Resource Adequacy in the Desert Southwest – Key Findings

Key Finding #1: Load growth & resource retirements are creating an urgent need for new resources in the Southwest

Key Finding #2: Utilities' current resource plans have identified sufficient capacity additions to maintain reliability

Key Finding #3: A large share of the region's long-term needs will be met with solar, storage, and other "non-firm" resources

Key Finding #4: Even as solar and storage grow, the region's remaining firm resources will be needed for reliability

Key Finding #5: Substantial reliability risks remain as the region's electricity resource portfolio transitions

Maintaining reliability will require immediate and sustained action over the next decade

Supply Resilience in PNM Planning Key Takeaways

- **Portfolios planned with a reliability standard in mind vary in performance during extreme events**
- **Stress testing candidate portfolios for resilience is important to understand differences in their performance**
- **Winterization helps reduce outages and firm up generation reducing the severity of extreme event impacts**
- **During ice storms, broader southwest dynamics will have significant impact on PNM's ability to avoid outages under extreme events**
  - PNM can weather localized ice storms by relying on external markets, but region-wide events almost certainly lead to outages.
  - Market support is limited in summer and PNM's system can avoid outages during a heat wave unless load reaches 1-in-20 levels or significant level of generation is forced out.
- **PNM should continue to monitor risk profile in winter season. Resource accreditation should continue to match the risk profile PNM is presented with**
- **As PNM increases its storage portfolio, its operational limits and utilization should be understood and considered in resource adequacy modeling**

PNM RESOURCE ADEQUACY GOING FORWARD AND KEY QUESTIONS TO ANSWER (SUBSEQUENT MEETINGS)

Traditional systems designed around a LOLE standard (such as 1 day in 10 years) have similar performance if a loss of load event occurred (traditional portfolios did not vary much in the severity of event – EUE)

This study shows that focusing solely on LOLE can lead to portfolios that do vary significantly in the severity of an event if an event occurs.

1. Moving forward, should portfolios be designed to meet both a LOLE and an EUE requirement (Essentially should a decarbonized system should focus on providing the same attributes as a traditional system, just without carbon emissions)?

2. Along with bringing EUE into portfolios evaluations along with LOLE, should portfolios be further stress tested to gauge performance under adverse conditions as done in this study?

3. Finally, should the value of loss of load (which conceptually increase as a function of the duration of loss of load) be compared to the perceived cost of GHG?

PNM Talk to us.

PNM RESILIENCY STUDY

RESILIENCY STUDY PHASE II SCOPE OF WORK IDEAS, QUESTIONS TO ANSWER, ETC.

Given the limited data of actual events, what other ways do we have to synthesize extreme weather data?

How can we establish a (or what is a reasonable) baseline for portfolio metrics such as EUE?

What alternatives do we have for improving resiliency of the system aside from only utility scale resources?

What is the most cost-effective way of improving both summer and winter resilience?

What would be necessary to assess transmission within this current framework?

Is storage duration critical, or is storage volume more important and what is the cost tradeoff?

PNM Talk to us.

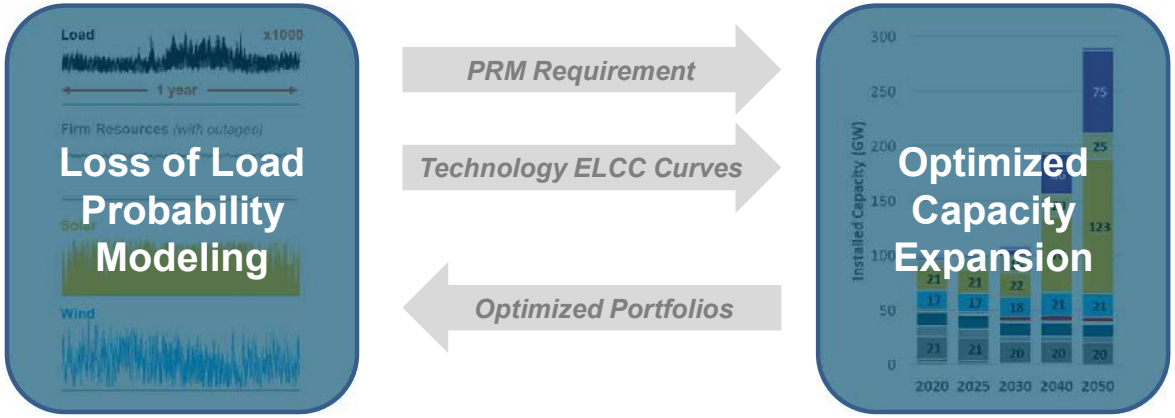
OPEN FORUM

Stakeholders with ideas, slides/examples to share, etc.

2020 IRP MODELING FRAMEWORK

The 2020 IRP modeling framework paired the EnCompass capacity expansion and production costing model with the SERVM loss-of-load-probability model to generate optimized portfolios that adhered to establish reliability metrics while meeting clean energy goals and minimizing cost.

1. Use LOLP model to quantify PRM requirement and "effective load carrying capability," which measures contribution of each resource-to-resource adequacy across 1000s of years

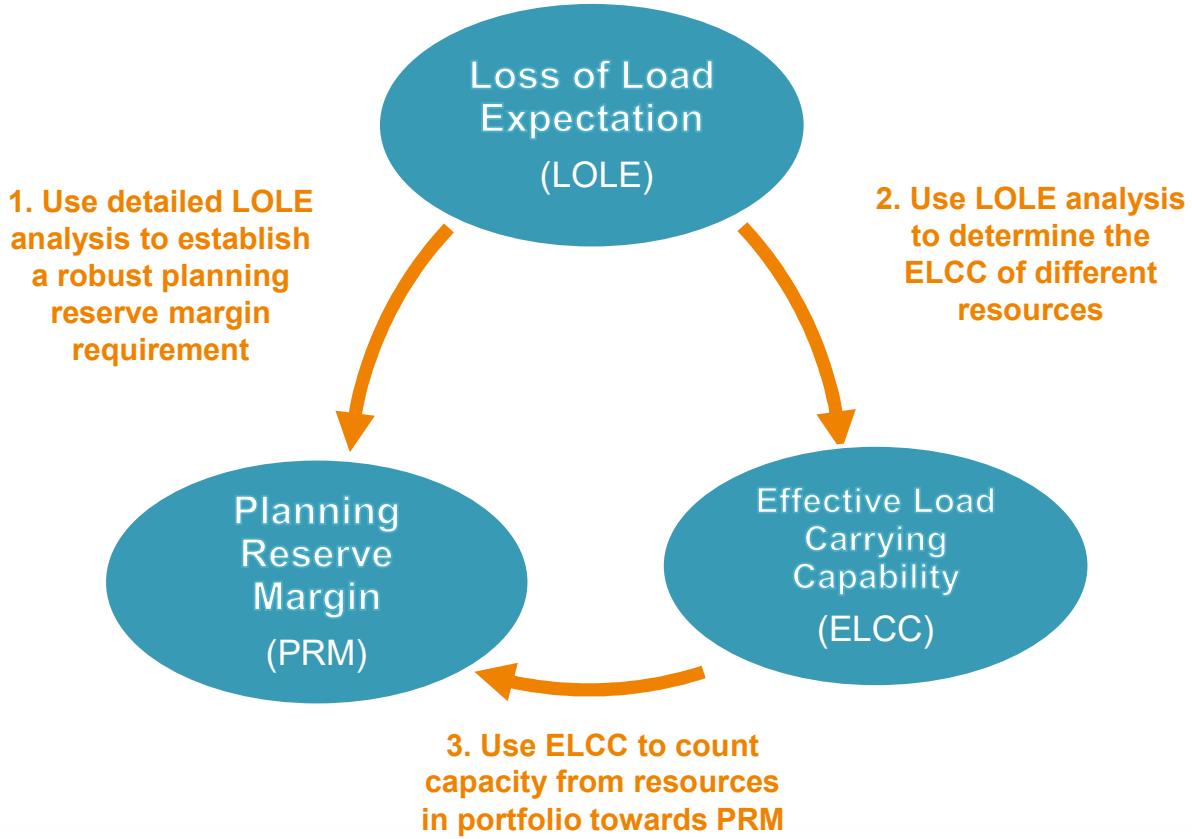


2. Use capacity expansion to optimize future portfolios to meet PRM requirement and clean energy goals while minimizing cost

3. Use LOLP model to simulate performance of resulting portfolios across wide range of conditions, validating resource adequacy

PNM Talk to us.

RESOURCE ADEQUACY MODELING



OPEN FORUM

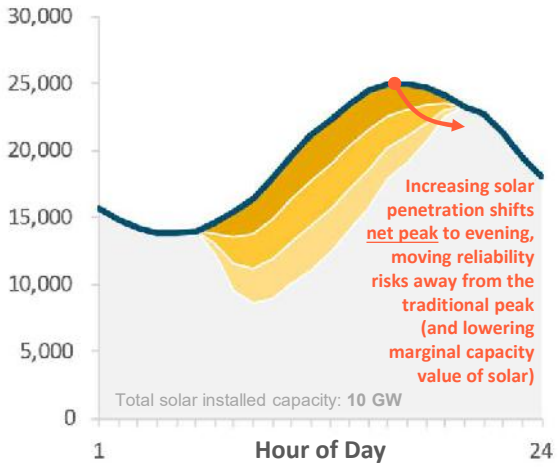
Stakeholders with ideas, slides/examples to share, etc.

Variable and energy-limited resources contribute to resource adequacy, but also add complexity

1

"Variable" resources shift reliability risks to different times of day

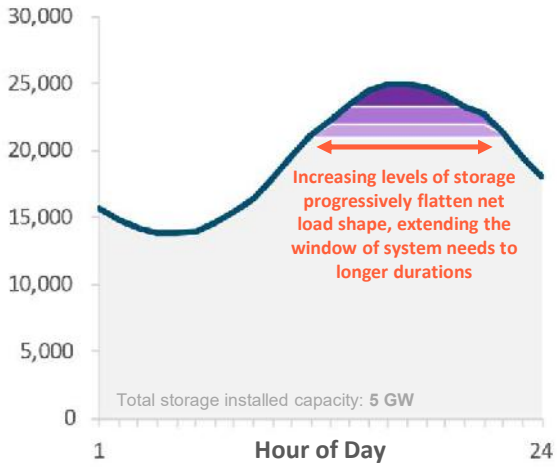
Solar Impact on Net Load
(MW)



2

"Energy-limited" resources spread reliability risks across longer periods

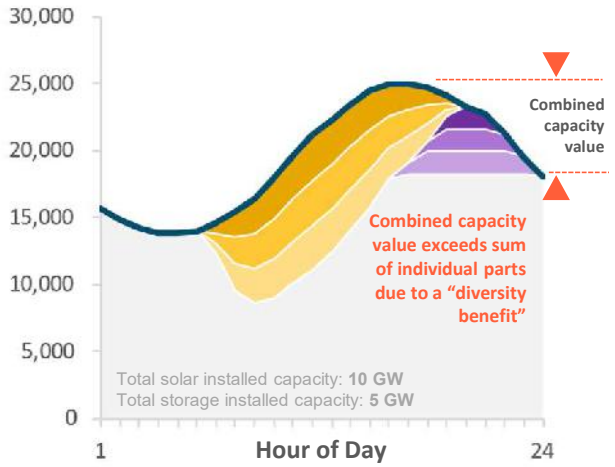
Storage Impact on Net Load
(MW)



3

A portfolio of resources exhibits complex interactive effects, where the whole may exceed the sum of its parts

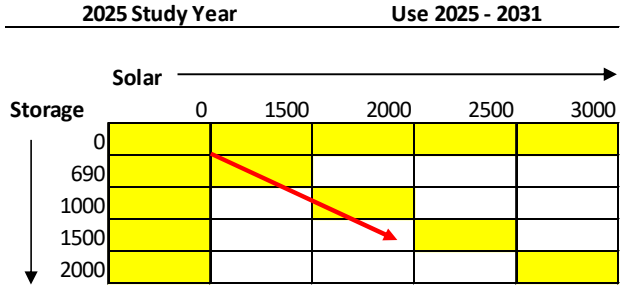
Combined Solar & Storage Impact on Net Load
(MW)

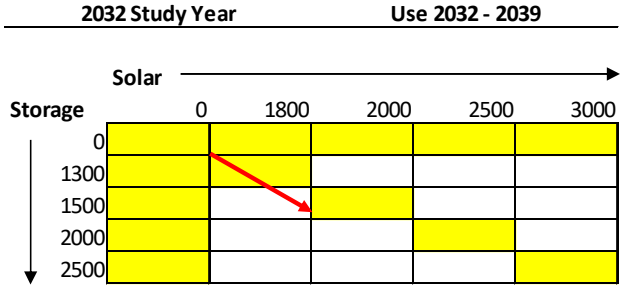


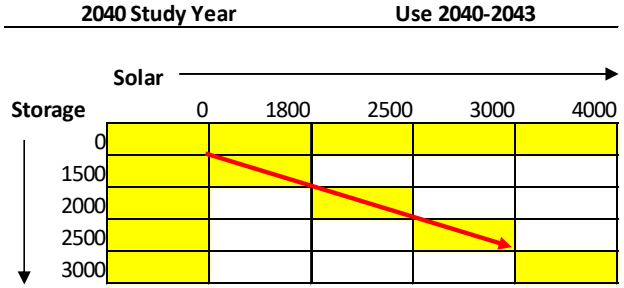
ELCC Synergistic Value

Installed Capacity – PVNGS NNC

Sum of Capacity (MW)	Column Labels																			
Row Labels	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal:Conventional	697	697	200	200																
Demand:Distributed Generation	33	48	48	15	15	15	15	15	15	15		15	15	15	15	15	15	15	15	15
Demand:Energy Efficiency	20	39	60	83	107	114	121	128	134	141	148	155	142	130	117	124	107	90	92	95
Gas/Oil:Combined Cycle	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	
Gas/Oil:Combustion Turbine	416	416	416	416	416	416	416	416	267	267	267	267	267	267	267	267	267	267	267	126
Gas/Oil:Steam Turbine	146	146	146	146	146	146	146	146	146	146										
Nuclear:Nuclear	402	402	298	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288
Renewable:Geothermal	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Renewable:Solar PV	378	1025	1521	1687	1771	1755	1743	1732	1720	1709	1698	1686	1675	1664	1663	1723	1713	1701	1770	3080
Renewable:Wind	658	658	658	658	658	658	658	658	658	658	658	658	658	658	556	556	556	556	556	956
Storage:Battery		300	590	690	846	937	959	1129	1136	1136	1304	1304	1320	1341	1382	1395	1421	1449	1569	2390







- **Evaluate resources individually**
- **Evaluate resources as a portfolio**
- **Appropriately allocate synergistic benefit**

Note this is a two dimensional illustrative example

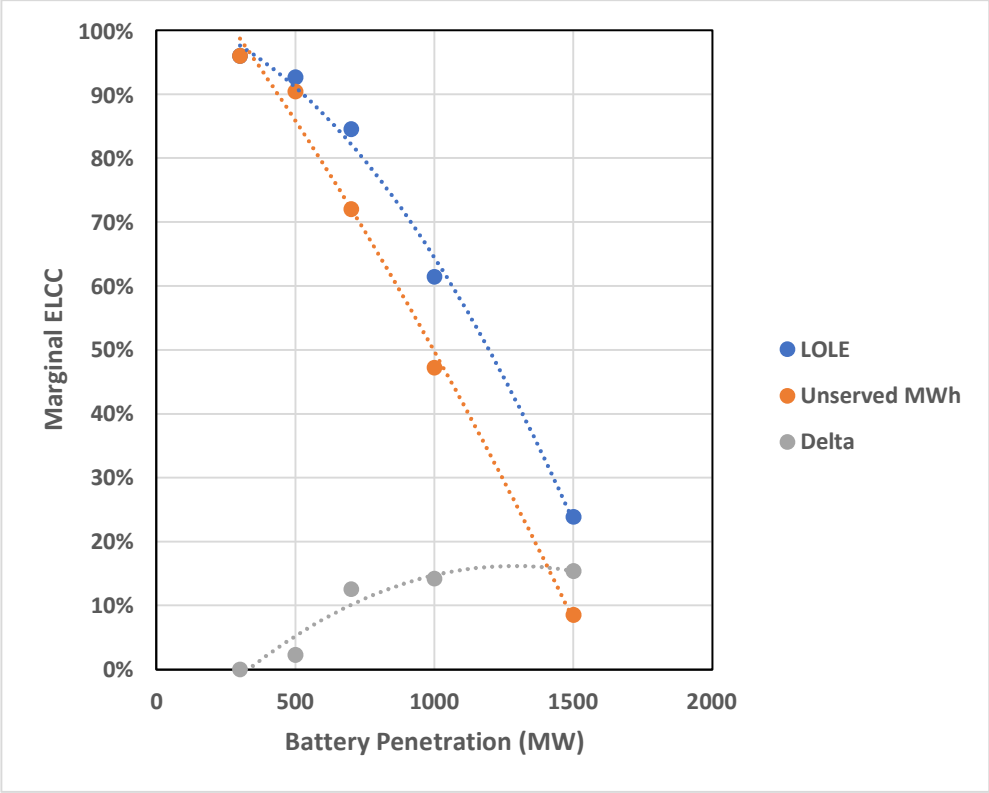
ASTRAPÉ CONSULTING
innovation in electric system planning

OPEN FORUM – MODELING OF RESOURCE SYNERGISTIC EFFECTS

Stakeholders with ideas, slides/examples to share, etc.

PNM Talk to us.

2020 IRP ELCC (LOLE vs EUE Metric)



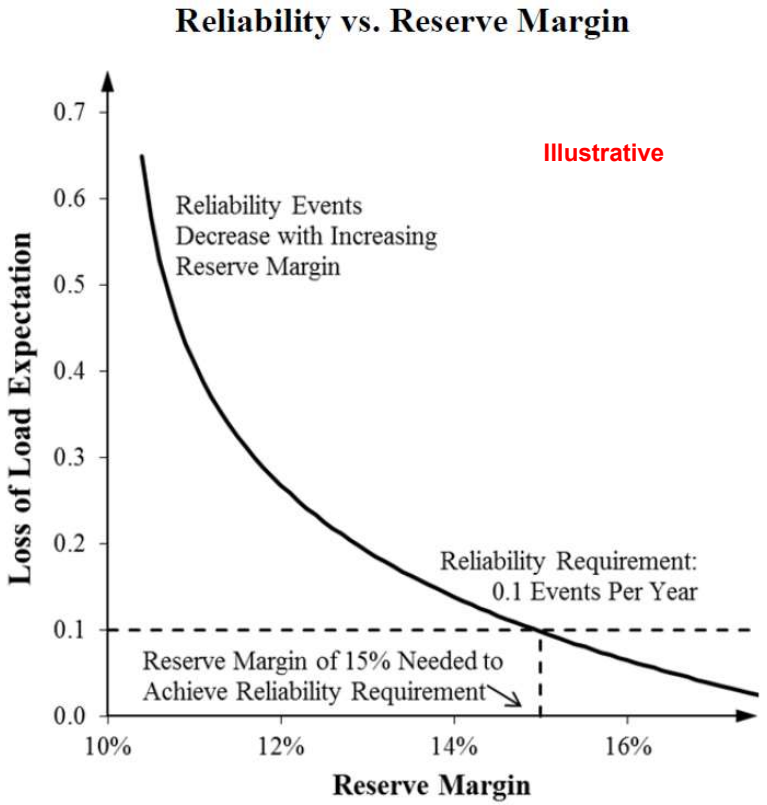
Compounding the complexity of the previous slide is when do we switch from LOLE ELCC curves to EUE ELCC curves… or do we?

ASTRAPÉ CONSULTING
innovation in electric system planning

Physical Reliability Metrics

- **Loss of Load Expectation (LOLE)**
  - Counts the number of days load was not met
  - 1-day-in-10-year Standard
    - Most used metric by RTOs, Utilities, and Commissions
    - Equates to 0.1 days per year for modeling purposes
    - Allows 1 day (1 event) every 10 years

- **Additional Metrics**
  - Loss of Load Hours (LOLH)
    - Counts the number of hours load was not met
  - Expected Unserved Energy
    - The amount of load in MWh not met



ASTRAPÉ CONSULTING
innovation in electric system planning

Survey Summary

Survey of Resource Adequacy Criteria Across U.S. and Canadian Power Systems

Region	Standard	Model	Notes
PJM[a]	0.1 LOLE	PRISM and GE-MARS	The LOLE based target reserve margin and various other calculations provide key inputs into the PJM capacity market.
MISO[b]	0.1 LOLE	SERVM	Performed Annually by the ISO. Regional reserve margin of 16.7% but after diversity allows its load serving entities to carry an 11.3% reserve margin.
NYISO[c]	0.1 LOLE	GE-MARS	Resulted in a reserve margin of 16.1% for the period May 2012 to April 2013. Reserve Margin calculation includes nameplate of all resources including wind. Results are adapted to derated UCAP for implementation in the NYISO capacity market.
ISO-NE[d]	0.1 LOLE	GE-MARS	2012 ICR report calculates the requirement needed to meet its 1 day in 10 year standard, load uncertainty considers weather but not economic forecast error. Results used capacity market.
SPP[e]	0.1 LOLE	SERVM	Capacity margin criterion of 12% for RTO members that are steam based and 9% for hydro based; results in capacity margin criterion above the 1 day in 10 year definition.
Maritimes[f]	20% RM and 0.1 LOLE	NPCC uses MARS	Maritimes uses a 20% reserve margin criterion for planning purposes but at the same time adheres to the NPCC requirement of not shedding firm load more than 1 day in 10 years.
Quebec[g]	0.1 LOLE	NPCC uses MARS	Based on an LOLE of 0.1, Quebec requires a 10% reserve margin for the 2012/2013 winter peak. By the 2015/2016 winter peak, Quebec requires a 12.2% reserve margin. Because of its dependence on hydro generation, Quebec also imposes an energy requirement to withstand 2 consecutive years of low water inflows.
IESO[h]	0.1 LOLE	NPCC uses MARS	The target for 2013 to meet the one day in 10 year target is 19.7% in which the region meets easily with an anticipated reserve margin of 40.1%.
Saskatchewan[i]	EUE Standard		Sask Power uses a 13% RM based on probabilistic analysis of Expected Unserved Energy.
Manitoba[j]	Both RM and energy standards due to hydro dependence		The energy criterion requires adequate energy resources to supply firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The capacity reserve margin is at least 12%.
MAPP[l]	1 day in 10 years (LOLE of 0.1)		Some MAPP members self-impose a planning reserve margin of 15% based on the results of an LOLE study performed in 2009.
SERC/ General	No mandatory requirement		RA targets set by individual load serving members subject to regulatory review. With this approach, the criteria and final reserve margins vary across the region.
SERC/SoCo[k]	0.1 LOLE/ Economics	SERVM	The target is based on analyzing LOLE and customer costs

https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf
Survey was performed in 2014 and has been updated for known changes

ASTRAPÉ CONSULTING
innovation in electric system planning

Survey Summary

Region	Standard	Model	Notes
SERC/Duke Energy Carolinas[l]	0.1 LOLE and Economic Assessment	SERVM	Set minimum RM based on LOLE values but base target RM on an economic assessment, which is slightly higher than the LOLE target.
SERC/ Progress Energy Carolinas[m]	1 day in 10 years (LOLE of 0.1) and Economic Assessment	SERVM	Set minimum RM based on LOLE values but base target RM on an economic assessment, which is slightly higher than the LOLE target.
SERC/TVA[n]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/Santee Cooper[o]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/ LGE&KU[p]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/ Entergy[r]	1 day in 10 years (LOLE of 0.1)	ERAILS	
SERC/ SCE&G[q]	12–18% RM		
FRCC[v]	0.1 LOLE	Tiger	"The FRCC has a resource criterion of a 15% minimum Regional Reserve Margin based on firm load. The FRCC assesses the upcoming ten-year summer and winter peak hours on an annual basis to ensure that the Regional Reserve Margin requirement is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum Reserve Margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC. Other utilities employ a 15% to 18% minimum Reserve Margin planning criterion."
ERCOT[s]	0.1 LOLE target (not mandatory)	Internal Model	ERCOT operates as an energy-only market and so does not mandate a RM; but performs one day in 10 year standard assessment to inform ERCOT and
WECC/ General[t]	No mandatory requirement		Individual balancing areas within WECC determine their own resource adequacy requirements in various ways and are subject to review by state regulators
CAISO[w]	15% RM		In January 2004, the CPUC established a long-term Resource Adequacy framework (D.04-01-050). This decision adopted a 15% to 17% planning reserve margin (PRM) and directed that each LSE is responsible for acquiring sufficient reserves to meet its own customer load. CAISO has since performed LOLE studies but the studies have not impacted the decision made in 2004 to maintain at a minimum 15% reserve margin

https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf
Survey was performed in 2014 and has been updated for known changes

A TRAPÉ CONSULTING
innovation in electric system planning

Survey Summary

Region	Standard	Model	Notes
Northwest/ BPA[v]	Loss-of-Load Probability (LOLP) of 5%; and conditional value at risk (CVaR) to evaluate energy not served (ENS) events	Genesys Model	A completely different method from 1 day in 10 years. Method was developed in cooperation with the Northwest Council to take into account the predominantly hydro resource mix of the Northwest. For this use, LOLP is not defined as hours per year. It is instead a percentage of iterations that contain any EUE. The target allows no more than 5% of all iterations to contain EUE.
Southwest/ APS[w]	0.1 LOLE		APS 2012 IRP states that at 15% planning reserve margin criterion, LOLE is less than 1 day in 10 years.
Southwest/ PNW[x]	NM State Commission set target at 13%		Notes that reserve margin would likely increase if a one day in 10 year standard were used.
Southwest/ NV Energy[y]	1-in-10		Definition of 1 day in 10 years is not reported.
Alberta	No RA requirement		Intervention possible if expected EUE over a two-year outlook increases above 1,600 MWh.

https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf
Survey was performed in 2014 and has been updated for known changes

ASTRAPÉ CONSULTING
innovation in electric system planning

2023 IRP ELCC (LOLE vs EUE Metric)

- **Premise: Maintain reliability the system has seen historically during the decarbonization transition**
  - Maintain 0.1 LOLE – 1 day in 10 year standard
  - Explore EUE or LOLH metrics for a current or historical PNM configuration to set a baseline target
    - SJ Coal not retired
    - Remove renewable/storage

- **Force future portfolios to meet 0.1 LOLE and EUE/LOLH secondary constraints**
  - It is expected at some point that the system will be able to meet the 0.1 LOLE metric and not meet the EUE/LOLH metric as significant energy limited resources are include on the system.
  - ELCCs would reflect EUE/LOLH constraints

ASTRAPÉ CONSULTING
innovation in electric system planning

OPEN FORUM – RELIABILITY METRICS

Stakeholders with ideas, slides/examples to share, etc.

PNM Talk to us.

2023 IRP PUBLIC ADVISORY PROCESS

WE WOULD LIKE TO HEAR FROM YOU

We did not receive any feedback to these questions posted during the last public meeting:

1. What did we do well in the last (2020) IRP and where can we improve?
2. Any additional ideas for technical discussions?
3. What is the proper way to balance reliability, customer cost and accelerating the transition to clean energy?
4. How can we be more collaborative throughout the process with our public stakeholders?

We would also like to hear your ideas on the How we incorporate key takeaways and lessons learned from the Resiliency Study Phase I into the 2023 IRP so we can begin these discussions at our June 8, 2022 meeting.

We would also like to hear your ideas on the Resiliency Study Phase II Scope of Work / Questions to Answer.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: June 22, 2022

Topic: Public Advisory Steering Mini Session (Energy Efficiency Potential Study SOW) & Technical Session #2 (Modeling for Reliability, Resource Adequacy and Resiliency Continued)

Start Time: 9:00 AM

Location: Virtual

Due to the vast majority of participants for the first two meetings attending virtually, we have decided to make the second technical session a virtual meeting. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

PNM Talk to us.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: July 6, 2022

Topic: Public Advisory Technical Session #3: Load Forecast Scope of Work / Methodology & Candidate Resource Pricing Methodology

Start Time: 9:00 AM

Location: Virtual

Due to the vast majority of participants for the first two meetings attending virtually, we have decided to make the third technical session a virtual meeting. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by June 16, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Energy Efficiency/Market Dynamics/Resiliency

MINI STEERING/TECHNICAL SESSION #2

JUNE 22, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING AGENDA

- Welcome and Introductions
- Energy Efficiency:
  - EE Potential Study Statement of Work
  - Review of EE modeling in the IRP
  - Open forum for any stakeholder discussion on how to incorporate the EE Potential Study into the IRP
- Reliability/Resource Adequacy/Resiliency – Technical Session #1
  - recap
  - Feedback/Questions
  - Feedback/guidance for incorporating changes to PNM's modeling
- Market Dynamics (Market Liquidity Updates/Import Limits
- Next steps and Near-Term Schedule

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01

- Questions and comments are welcome – One Person Speaks at a Time

02

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

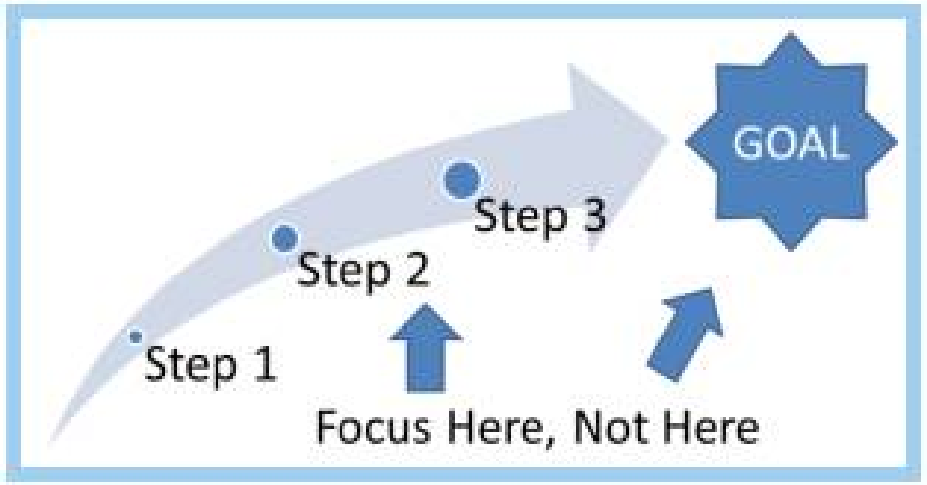
03

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

ENERGY EFFICIENCY - ENABLING LEGISLATION AND NMPRC RULE



Efficient Use of Energy Act (EUEA)

- Extended in 2019 legislative session
- Mandates cost-effective programs
  - Benefits must be greater than costs
  - Benefits = value of saved energy
  - Costs = all costs related to programs
- Requires independent measurement and verification (M&V)
- Funding = no less than 3% and no greater than 5% of - customer bills
- Minimum savings = 5% of 2020 sales by 2025
- PRC approved PNM's EE/LM 2021-2023 Program Plan – October 28, 2020

2023 PRELIMINARY PNM ENERGY EFFICIENCY PLAN OVERVIEW

- Evaluating all 2021 programs for consideration to continue
  - 2023 plan budget is based on 3% - 5% of customer bills
  - 2023 plan savings is based on achieving minimum 5% of 2020 retail sales (~ 400 GWh) Retail sales are defined as those customers paying Rate Rider 16
    - » 2021 savings 107 GWh
- 2023 plan budget projected to remain consistent with 2021 program plan filing (~ $90 million over 3 years)
- AEG Contracted for EE Potential Study Update
  - Statement of Work
  - Why PNM contracted
  - EE potential study in progress – completion Q3 2022
  - Used to assist/confirm program design/offerings

AEG
APPLIED ENERGY GROUP

EE Potential Study Stakeholder Kickoff Meeting

Date: June 22, 2022

Agenda

- Introductions
- Stakeholder Engagement Plan
- Study Overview
- Energy Efficiency Potential
- IRP Inputs
- Identify Strategic Issues

Introductions



Kelly Marrin
Managing Director
Role: Project Director



Barb Ryan
Project Manager
Role: RASS Advisor



Len Bergman
Manager
Role: Project Manager



Rob Strange
Product Manager
Role: Modeling Lead



Eli Morris
Managing Director
Role: IRP Input Lead



Fuong Nguyen
Lead Analyst
Role: Analysis Lead

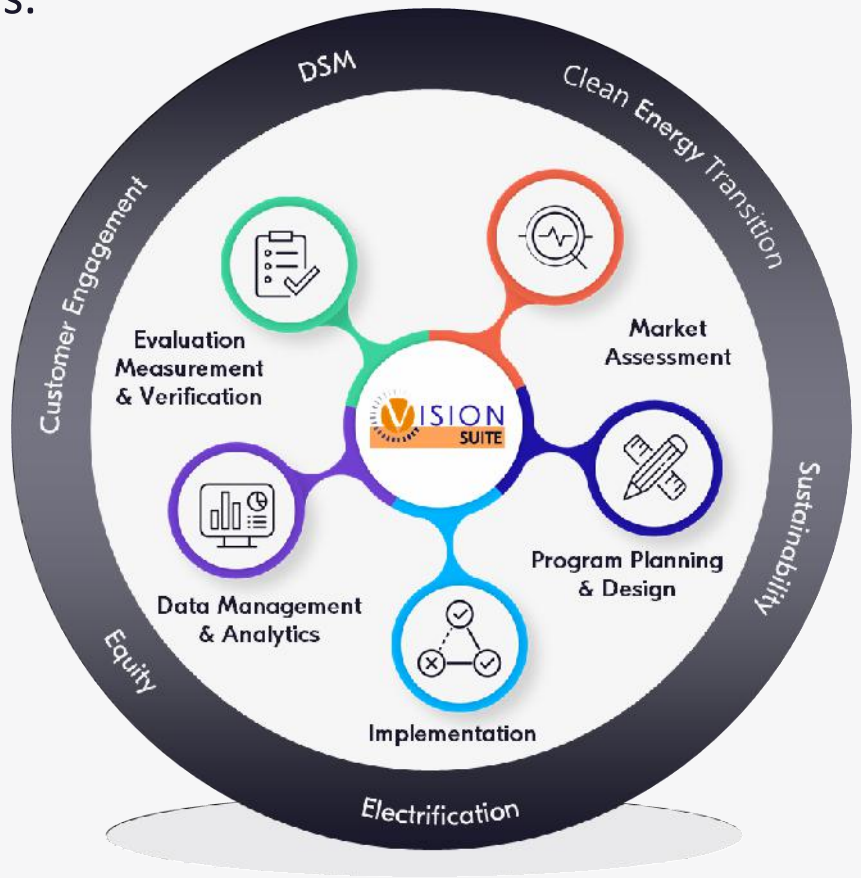
Presenter

About AEG

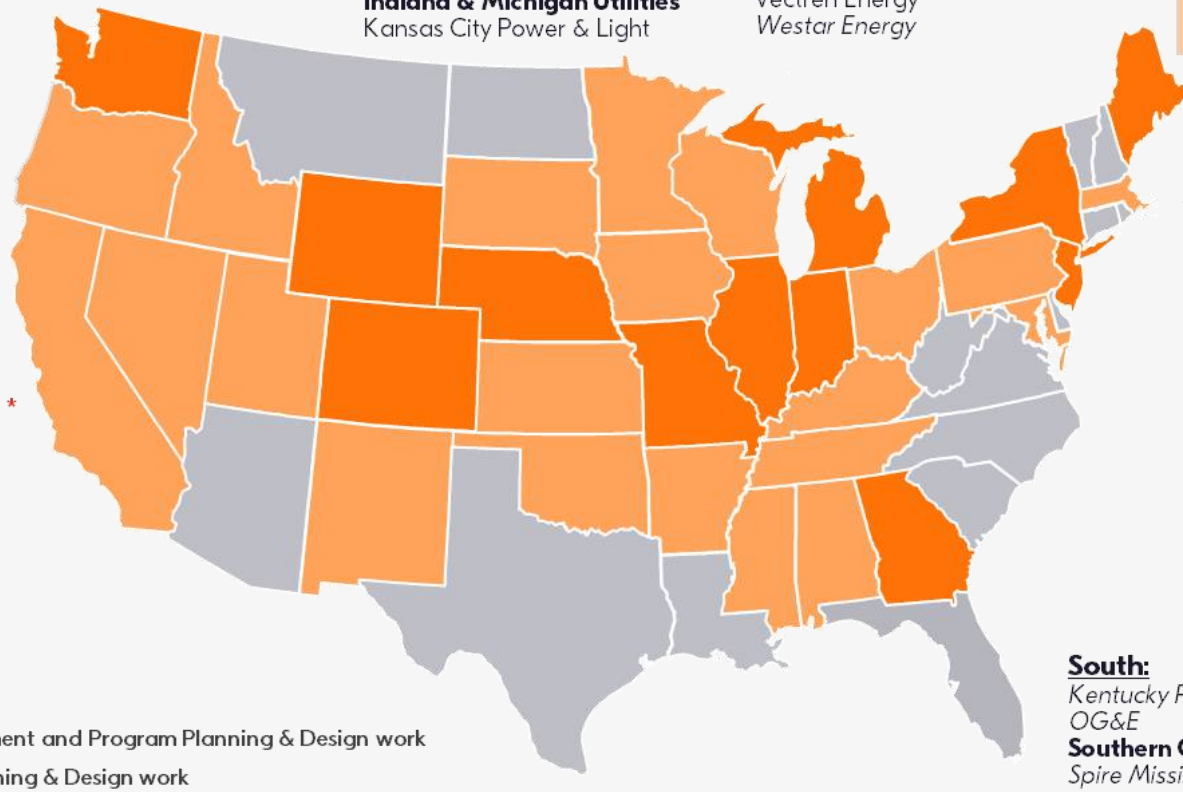
Founded in 1981 | Join Ameresco 2011

AEG provides expertise, products, and insights to utilities and other agencies to solve current and future business and sustainability needs.

85	Dedicated Professionals
49	States and provinces in which we've worked
200+	Utility and govt. clients served
1,000+	Projects completed



Our DSM Potential Study and Program Planning Footprint



West:
Avista Energy *
BPA *
Cascade Natural Gas *
Chelan PUD
Cheyenne LFP *
Colorado Electric *
Cowlitz PUD *
HECO
Idaho Power *
Inland P&L *
LADWP
NV Energy
Oregon Trail EC
PacifiCorp *
PNGC
PG&E *
Portland General Electric
Public Service New Mexico *
Seattle City Light *
State of Hawaii *
State of New Mexico
Tacoma Power *
Xcel/SPS

Midwest:
Ameren Illinois *
Ameren Missouri *
Black Hills Power *
Citizens Energy
Empire District Electric *
Indianapolis P&L*
Indiana & Michigan Utilities
Kansas City Power & Light

MERC
NIPSCO *
Omaha Public Power District *
Peoples' Gas/ North Shore Gas *
Spire Missouri
State of Michigan
Sunflower Electric
Vectren Energy *
Westar Energy

Regional & National:
Midcontinent ISO *
EEI/IEE *
EPRI
FERC

Northeast:
Berkshire Gas
Central Hudson G&E *
Con Edison of NY *
Efficiency Maine *
Liberty Utilities *
New Jersey BPU
Orange & Rockland *
PECO Energy
PSEG Long Island
Rockland Electric
Unitil

South:
Kentucky Power *
OG&E
Southern Company / Georgia Power
Spire Mississippi
State of Maryland – EmPOWER *
TVA

Key

* Two or more studies

Bold = Both Market Assessment and Program Planning & Design work

Italics = Only Program Planning & Design work

As of January 2022

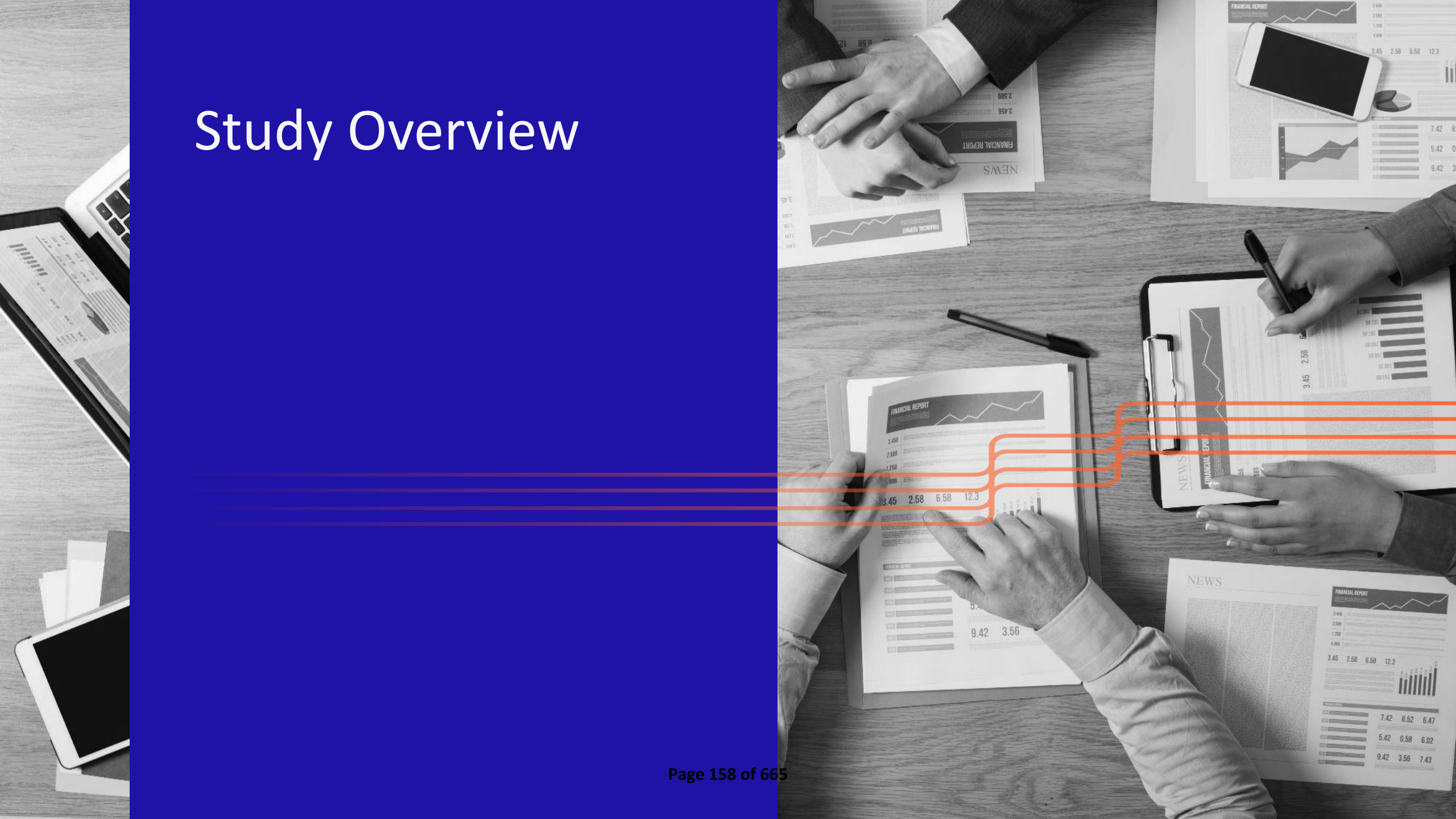
- 60 potential studies in last 5 years, 17 for Midwest utilities and MISO
- Long-standing relationships with more than a dozen clients

Stakeholder Engagement Plan

Engaging Early and Often

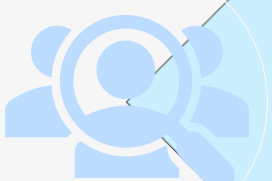
Meeting	Stakeholder Kickoff Meeting	Draft Potential Results	Refined Potential Results and Draft IRP Bundles	Share Final Results
Timing	June 2022	August 2022	September 2022	October 2022
Purpose	• Provide an overview of the DSM Potential Study and IRP input development • Identify stakeholder positions on key issues for the DSM Potential Study	• Review draft results of the DSM Potential Study • Gather initial feedback from stakeholders on the results of the study	• Review refined results of the Potential Study and draft bundles • Gather stakeholder feedback on results	

Study Overview



Study Objectives

There are 3 overarching objectives for the study



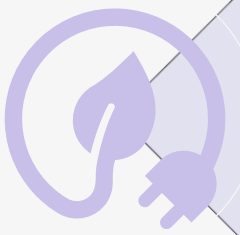
Incorporate Key Updates from the 2019 Study

- Incorporate results from the 2020 RASS that AEG completed with Itron
- Perform limited updates to the measure list



Develop New Projection of EE Potential

- Use AEG's upgraded potential assessment tool VisionInsight
- Align with Itron's EE forecast and program scenarios
- Project technical, economic, achievable, and programmatic EE potential through 2042



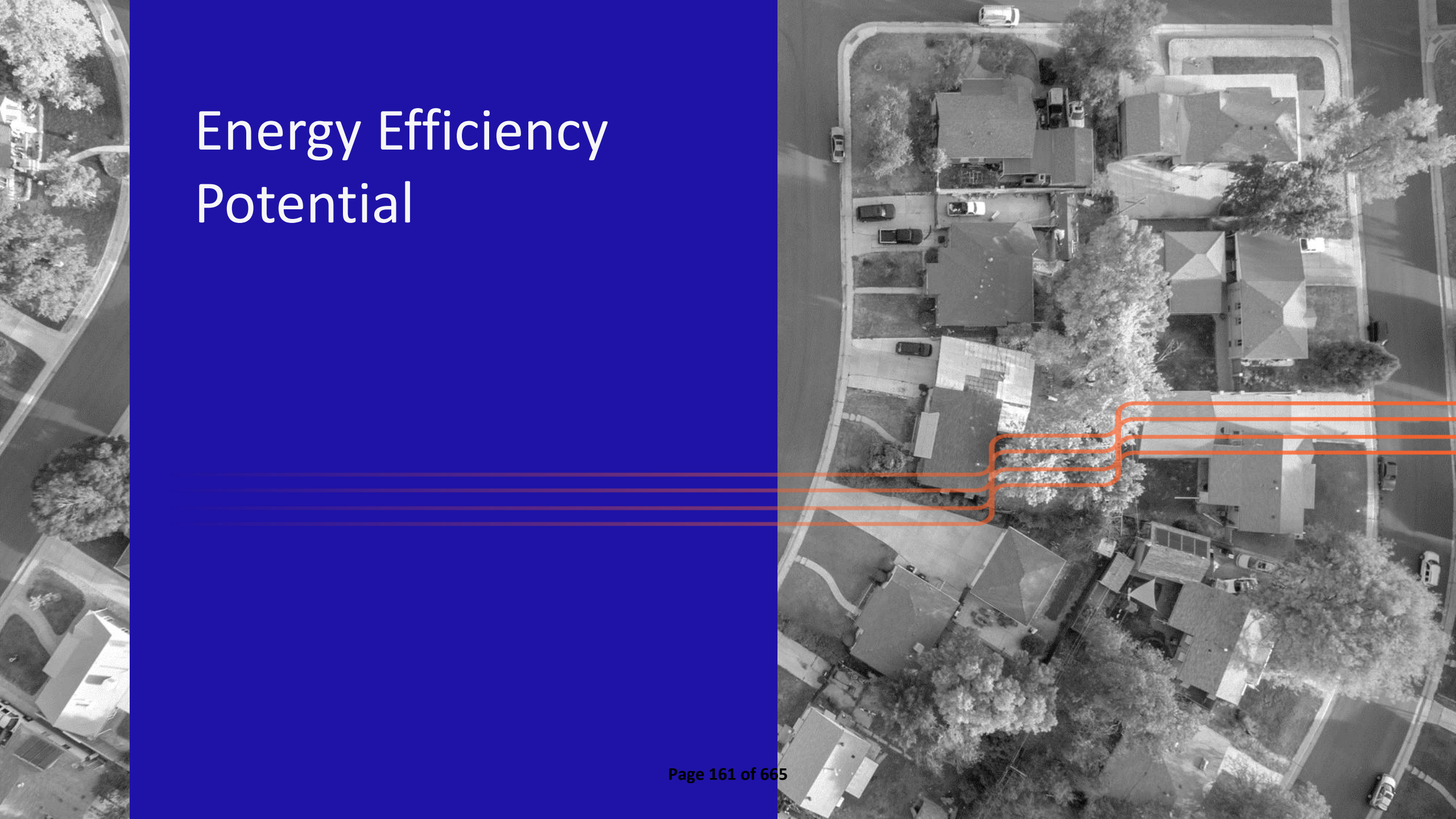
IRP Bundle Development

- Determine the "right" number of EE bundles based on the previous study
- Develop bundle cutoffs
- Supply finalized bundles in IRP format

Project Timeline

Task	May	June	July	Aug	Sept	Oct
Task 1: Project Kickoff Meeting	Agenda & Memo					
Task 1: Data Collection & Validation	Data Request					
Task 1: Update Market Characterization	Analysis	Report				
Task 1 : EE Potential		Analysis	Prelim	Final		
Task 2: Program Potential		Analysis	Prelim	Final		
Task 2: Potential Reporting			Draft	Final		
Task 3: Load Shapes			Analysis	Final		
Task 4: IRP Bundles and Doc Memo				Prelim	Final	

Energy Efficiency Potential



Energy Efficiency Potential Approach

Market Characterization

- Customer segmentation
- Utility data
- Residential Surveys
- Secondary data

Identify and Characterize Measures

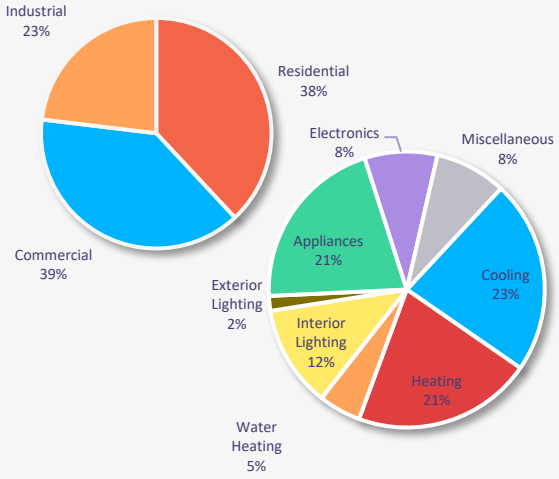
- Efficiency equipment
- Retrofit opportunities
- Emerging technologies

Baseline Projection

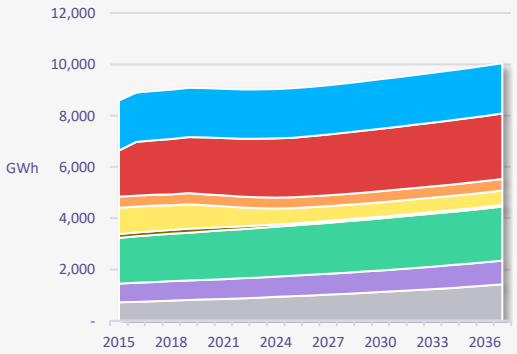
- Utility forecasts
- Stock turnover
- Codes and standards

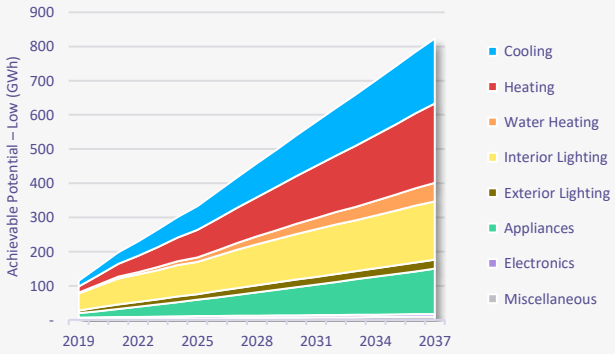
Potential Estimation

- Technical , Economic, and Achievable
- Scenarios around Statutory Goals









2020 Residential Appliance Saturation Survey

Objectives

- Gather current information about residential customers
- Update market characterization, baseline forecast and EE potential
- Maintain consistency with previous RASS studies

Topics

- Customer and dwelling characteristics
- Appliance saturations
- EE program awareness

Approach

- Target = 500
- Mail-to-web in 2020; mail only prior years

Analysis

- Review and prepare crosstabs
- Saturation inputs for EE and comparisons to prior years

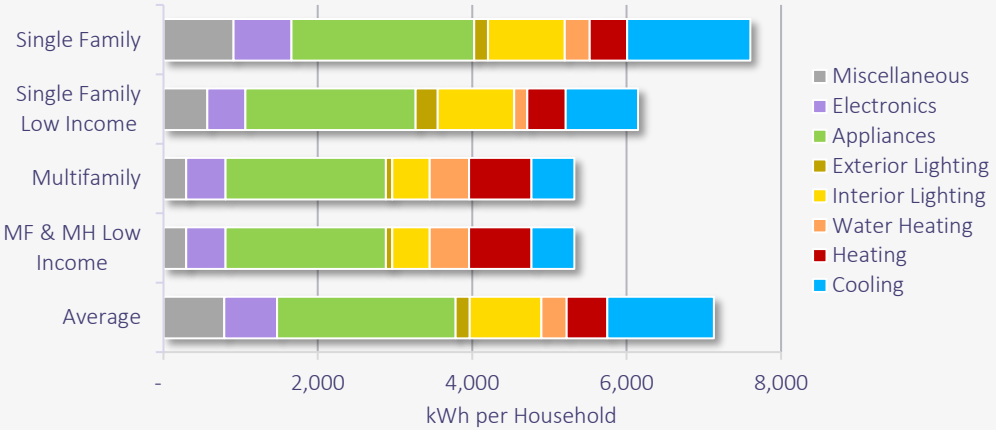


Market Characterization

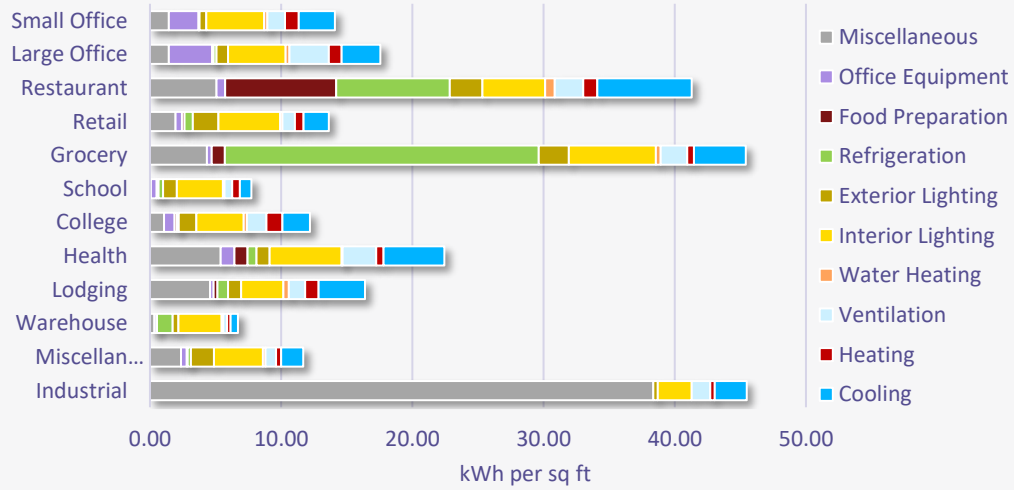
Key Elements and Drivers

- Market characterization is anchored to actual sales and customers in the study base year (2021)
- Segment residential sector based on dwelling type and income
- Segment commercial sector by building type using SIC codes
- Fully characterize energy consumption by sector, segment, end-use, and technology
  - We call these “market profiles”
- **Market Profiles Determine the baseline load, bound technical potential, and establish eligibility to adopt EE measures**

Residential Market Characterization from 2019 PNM DSM Potential Study

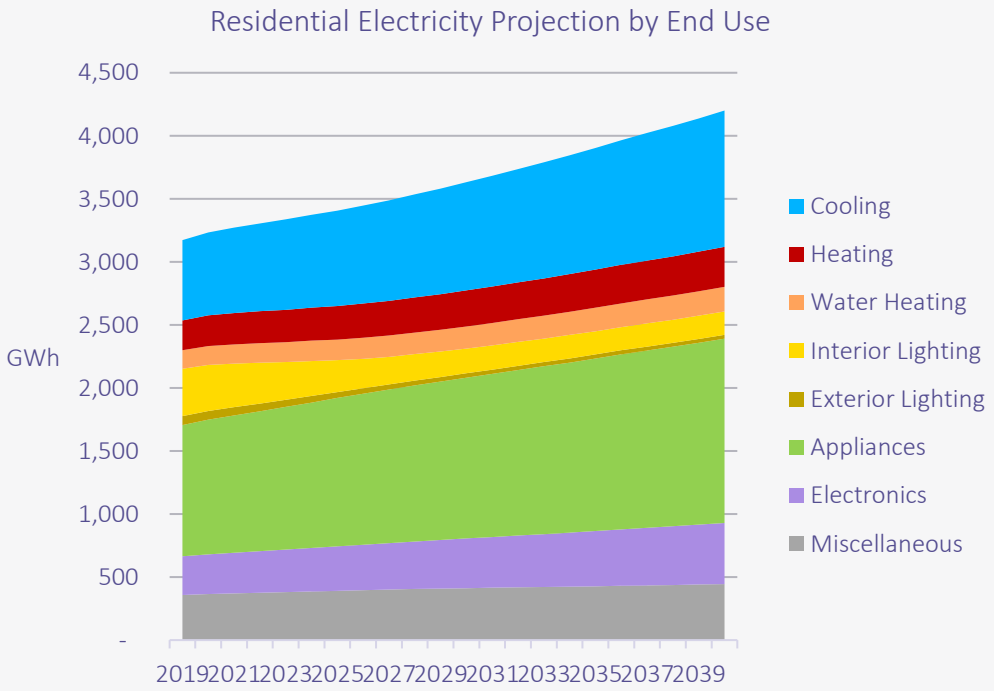


Commercial Market Characterization from 2019 PNM DSM Potential Study



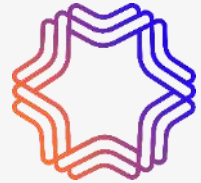
Baseline Projection

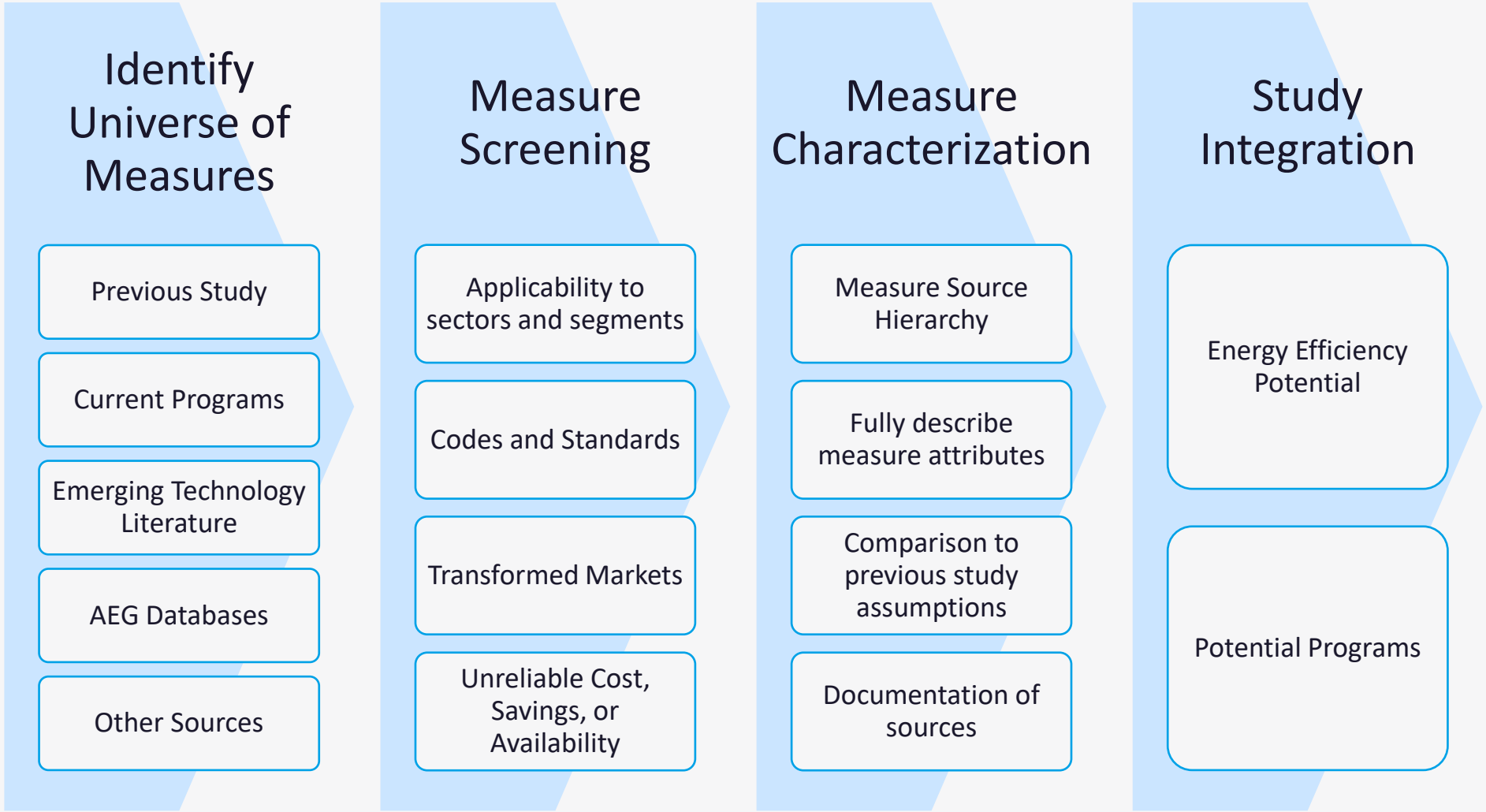
- Projects end-use consumption in the absence of future program interventions
  - This is the basis from which potential is estimated
- Accounts for:
  - Differences by sector, and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards **(including EISA)**
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
- We will align our projection with PNM / Itron's load forecasts
  - We will not match exactly, but will be close



Residential Projection from 2019 PNM DSM Potential Study

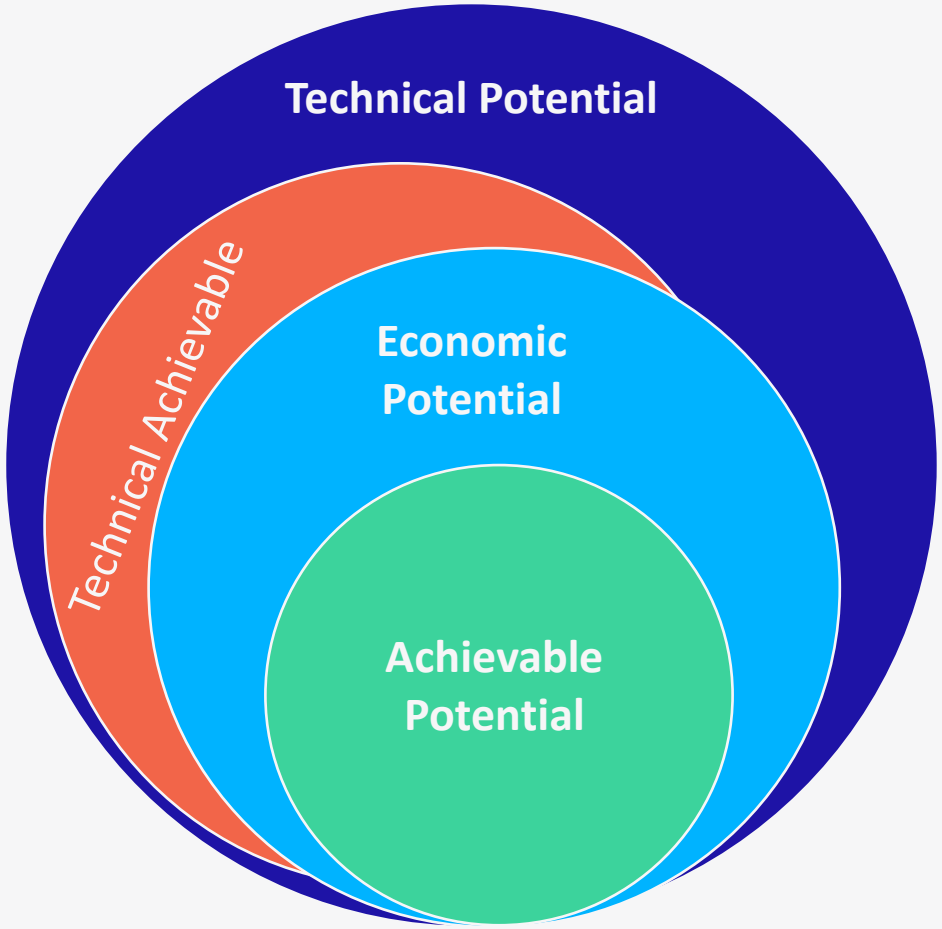
Measure Identification and Characterization





Estimating Energy Efficiency Potential

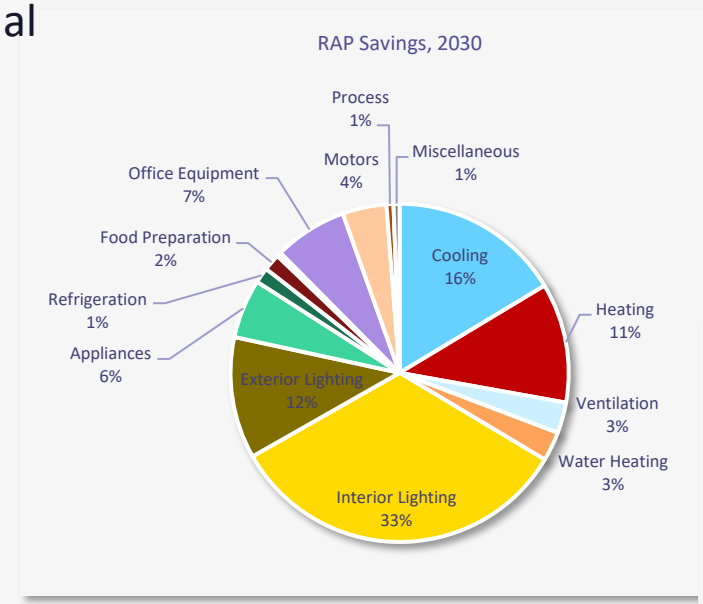
- Potential is estimated by creating an alternate sales forecast incorporating efficient measure adoption and calculating the change from the baseline
- AEG will calculate five distinct levels of potential:
  - Technical
  - Technical Achievable
  - Economic
  - Achievable
- AEG will also incorporate various scenarios that represent achievement of Statutory spending goals

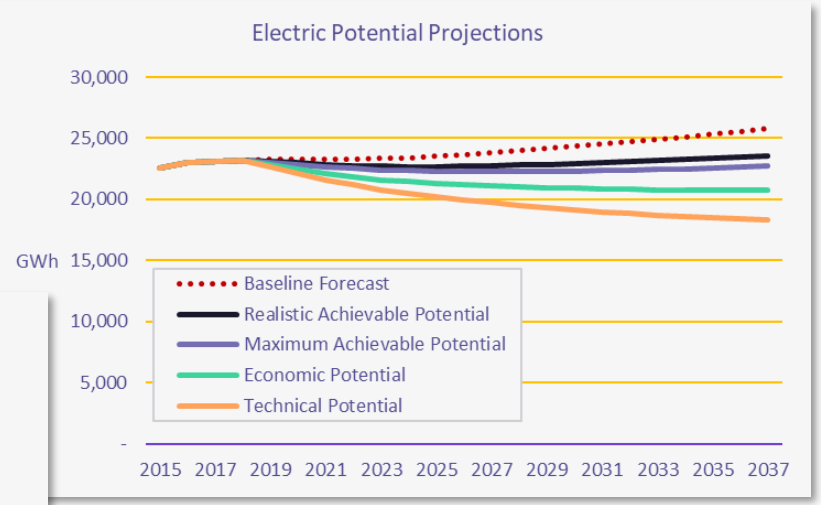


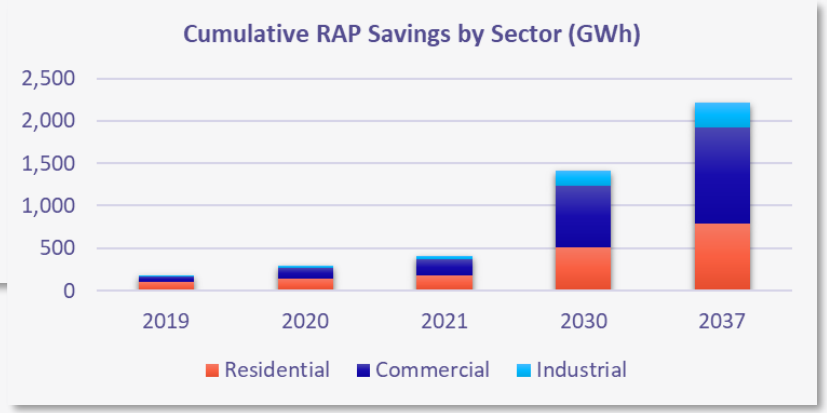
Outcomes from EE Potential Assessment

Provides a foundation for the development of IRP Bundles

- Understanding of mix of opportunities and associated costs
- Top measures for energy and seasonal peak savings
- Reasonable timeline of measure adoption over time







IRP Inputs


FINANCIAL REPORT
NEWS
3.45 2.58 6.58 12.3
9.42 3.56
7.42 8.52 6.47
5.42 0.58 6.02
9.42 3.56 7.43

Modeling Energy Efficiency Potential within the IRP

The EE Potential Assessment will identify the EE opportunities in PNM's service territory through 2042

Energy efficiency measures can be considered on par with supply-side resources based on their availability, hourly impacts, cost, and life.

- Program potential is the best representation of energy efficiency's likely effect on loads and resource needs, however:
  - HB 291 savings targets only run through 2025 with guidance to establish targets through 2029
  - The Program Potential is already screened for cost-effectiveness, so does not allow the IRP to consider higher-cost energy efficiency measures based on changing resource needs

To enable modeling energy efficiency as a resource within the IRP, AEG developed hourly supply curves representing program potential and additional opportunities not deemed cost-effective within the potential study

AEG Supply Curve Bundling Methodology

Identify Incremental Potential

- Use technical achievable potential as a starting point
- Incorporate acceptance rates but ignore cost-effectiveness
- Remove program potential to account for statutory goals



Define Bundles

- Cut offs defined using levelized cost of conserved energy
- Measures are assigned to bundles
- Measures are matched to calibrated load shapes

Statutory Period 2021-2025	Post-Statutory Period 2026-2040
Program Potential	n/a
Up to $50/MWh[1]	Up to $5/MWh
	$5/MWh to $15/MWh
	$15/MWh to $25/MWh
	$25/MWh to $35/MWh
	$35/MWh to $50/MWh
Over $50/MWh	Over $50/MWh

Savings & Costs for each Bundle

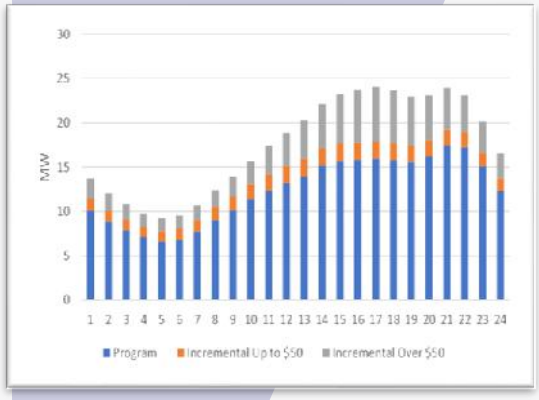
Calculate the following for each bundle based on measures:

- Annual incremental energy savings
- Weighted average cost
- Measure life

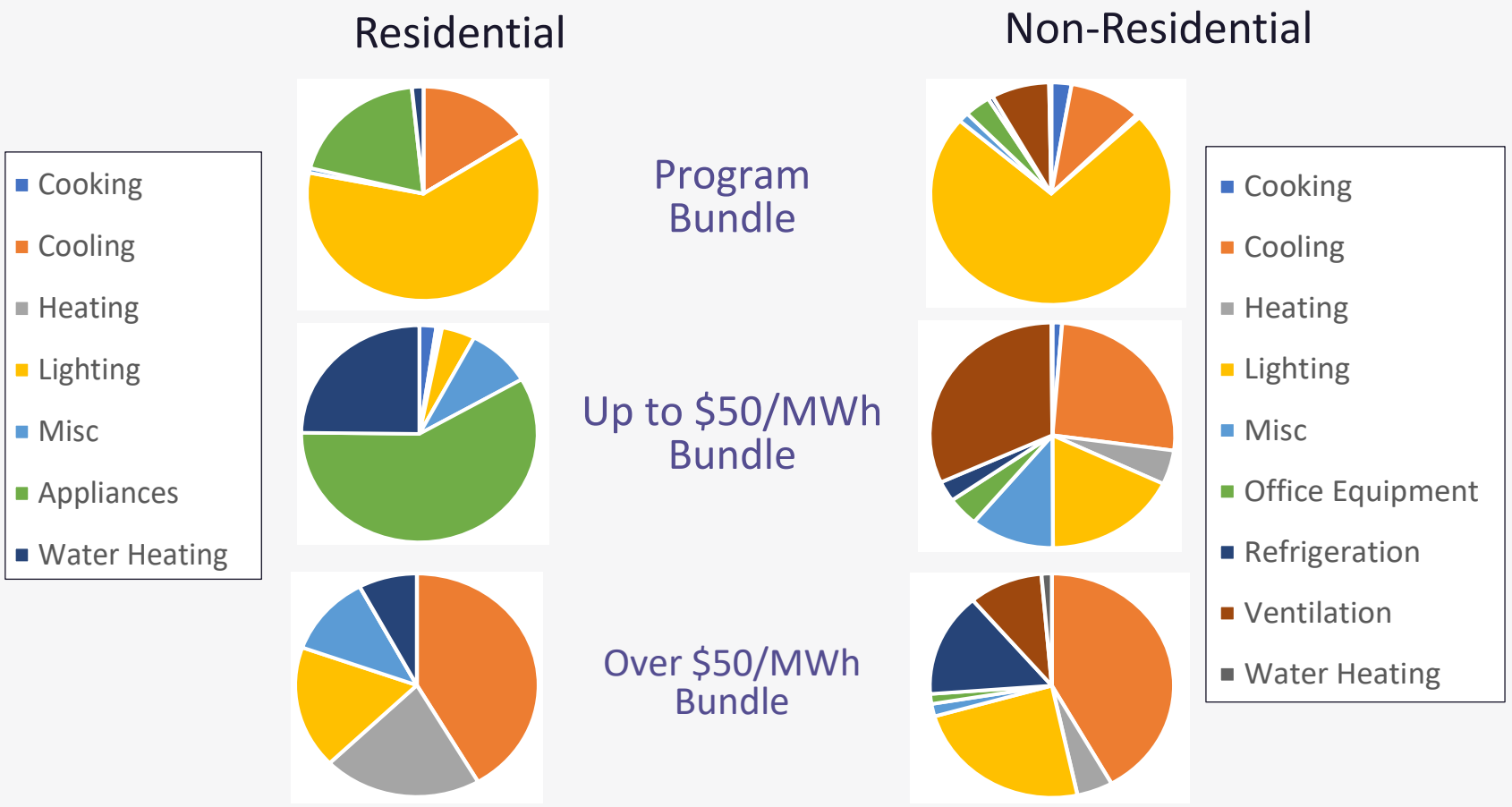


Hourly Impacts

- Estimate the hourly impacts for each bundle
- Spread measure level impacts over hourly load shapes
- Summarize load shapes



Example Bundle Composition - 2021



Comments or Strategic Issues?



Thank You.

Phone: 631-434-1414

AEG
APPLIED ENERGY GROUP

OPEN FORUM – ENERGY EFFICIENCY

Any questions, clarifications or concerns with how the potential study will be incorporated into the IRP?

JUNE 8TH TECHNICAL SESSION – RECAP

Key Topics Covered

- IRP Modeling Framework
  - Capacity Expansion/Loss of Load Probability modeling
- ELCC Modeling Synergies
- ELCC - LOLE Versus EUE metrics
  - Any feedback on additional metrics?

- Any feedback or new ideas regarding Resource Adequacy/Reliability/Resiliency modeling discussed from previous meetings?

Neighbor Modeling – SERVM Update

- **Updating Tier 1 Neighbor Loads and Resources**
  - Based on recent Southwest E3 study data
  - Public ERP and IRP data for PSCO and SPS
- **Modeling concerns from previous resource adequacy analyses which may overstate import capability**
  - Modeling may be missing surplus generation sales from Arizona to California /Nevada
    - Potential to capture historical net sales to California/Nevada as discussed on the next slide
  - Concerned that as energy limited resource such as storage and DR are added to surrounding systems, participants may be less likely to sell those resources during net peak periods

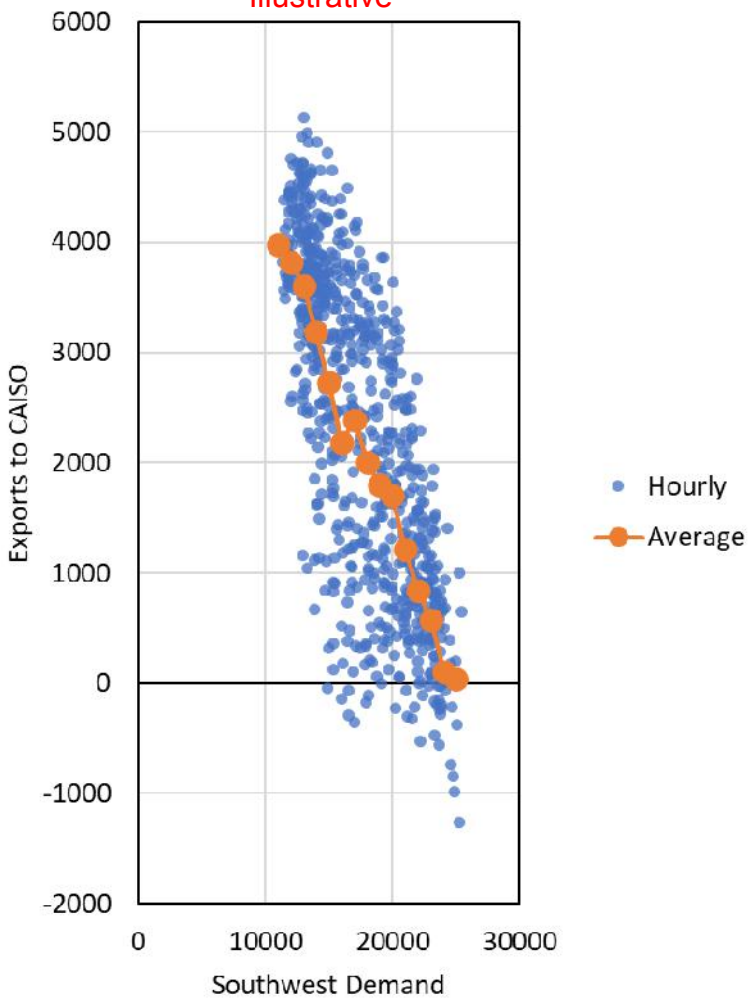
Neighbor Modeling

IRP analysis generally includes Tier-1 connections to PNM in the modeling framework

Historically, Tier-1 connections have exported significant MW into CAISO

Inclusion of CAISO exports may better capture illiquidity in bi-laterial capacity opportunities for PNM

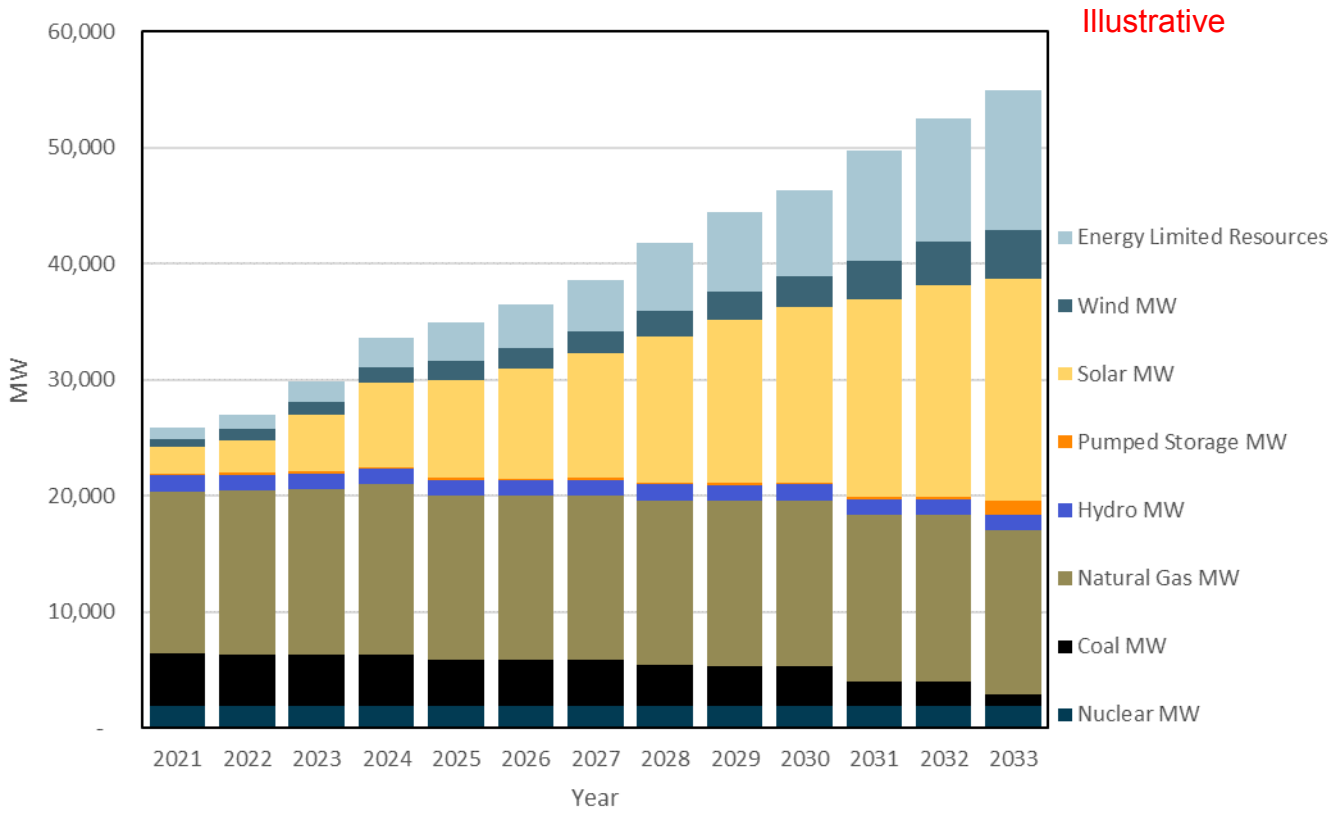
Illustrative



ASTRAPÉ CONSULTING
innovation in electric system planning

Evolving Neighboring Resource Mixes

- **The study also intends to capture the changing opportunities for PNM to purchase capacity (to charge storage at night , to serve net peak requirements, etc.)**



Neighbor Modeling

- **Import Limits – Currently same as PV Replacement Case and 2020 IRP**
  - SERVM allows for sharing based on economics and transmission constraints in all hours except for the following constraints
    - Limited to 200-300 MW in all hours when load is greater than 85% of the gross peak load
    - Summer (June – August) evening net peak load hours
      - Limit to 100-150 MW for hours 16-18 when load is greater than 85% of gross peak load
      - Limit to 50 MW for hours 19-22 from June to August when hourly gross load is greater than 80% of the gross peak load
        - 80% of gross load during hours 19-22 ensures this limit occurs on peak load days
    - No plans to change this currently based on continued resource adequacy concerns in WECC but will be reviewed after the 2022 summer

2023 IRP PUBLIC ADVISORY PROCESS

WE WOULD LIKE TO HEAR FROM YOU

We did not receive any feedback to these questions posted during the last public meeting:

1. What did we do well in the last (2020) IRP and where can we improve?
2. Any additional ideas for technical discussions?
3. What is the proper way to balance reliability, customer cost and accelerating the transition to clean energy?
4. How can we be more collaborative throughout the process with our public stakeholders?

We would also like to hear your ideas on the how we incorporate key drivers from the AEG Potential Study SOW and the 2023 IRP so we can begin these discussions at our July 6, 2022 meeting.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: July 6, 2022

Topic: Public Advisory Technical Session #3: Load Forecast Scope of Work / Methodology & Candidate Resource Pricing Methodology

Start Time: 9:00 AM

Location: Virtual

Due to the vast majority of participants attending virtually, we have decided to make future sessions virtual meetings until circumstances warrant in person attendance. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: July 27, 2022

Topic: Technical Session #4: IRP Modeling Updates/Techniques

Start Time: 9:00 AM

Location: Virtual

Due to the vast majority of participants for the first two meetings attending virtually, we have decided to make future sessions virtual meetings until circumstances warrant in person attendance. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

PUBLIC ADVISORY TOPICS AND SCHEDULE

UPCOMING PUBLIC INPUT MEETING DATES*

July 6, 2022: Technical Session #3 – Load Forecast/Candidate Pricing Methodology
July 27, 2022: Technical Session #4 – IRP Modeling Updates/Techniques
August 3, 2022 – Technical Session #5 – Other Modeling Assumptions
August 17, 2022: Steering Meeting #4 – Other External/Internal Studies
August 30, 2022: Steering Meeting #5 – Public Advisory Group Day
------Begin Monthly Meetings--------
September 21, 2022: Steering Meeting #6 – Modeling Inputs #1 – Existing System/Inputs
October 11, 2022: Steering Meeting #7 – Modeling Inputs #2 – Scenario Building
November 15, 2022: Steering Meeting #8 – Modeling Inputs #3 – Markets/Reliability/RFI
December 13, 2022: Steering Meeting #9 – Modeling Inputs #4 - Transmission

*meeting dates are subject to change. Dates are being finalized and will be posted on the website along with individual registration links.

PUBLIC ADVISORY TOPICS AND SCHEDULE

UPCOMING 2023 PUBLIC INPUT MEETING DATES*

January 17, 2023: Steering Meeting #10 – Modeling Results #1

February 14, 2023: Steering Meeting #11 – Modeling Results #2

March 14, 2023: Steering Meeting #12 – Draft IRP for comments

April 11, 2023: Steering Meeting #13 – Public Advisory Group Feedback Session #1

May 16, 2023: Steering Meeting #14 – Public Advisory Group Feedback Session #1

June 13, 2023: Steering Meeting #15 - Final IRP Presented (last meeting)

July 3, 2023: File IRP

*meeting dates are subject to change. Dates are being finalized and will be posted on the website along with individual registration links.

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by June 16, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Load Forecasting SOW Candidate
Resource Pricing Methodology

TECHNICAL SESSION #3 **JULY 6, 2022**



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

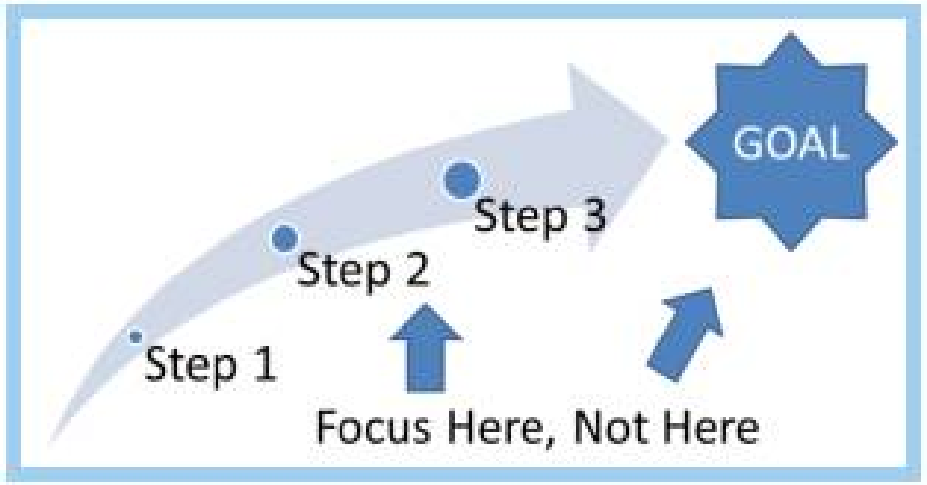
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



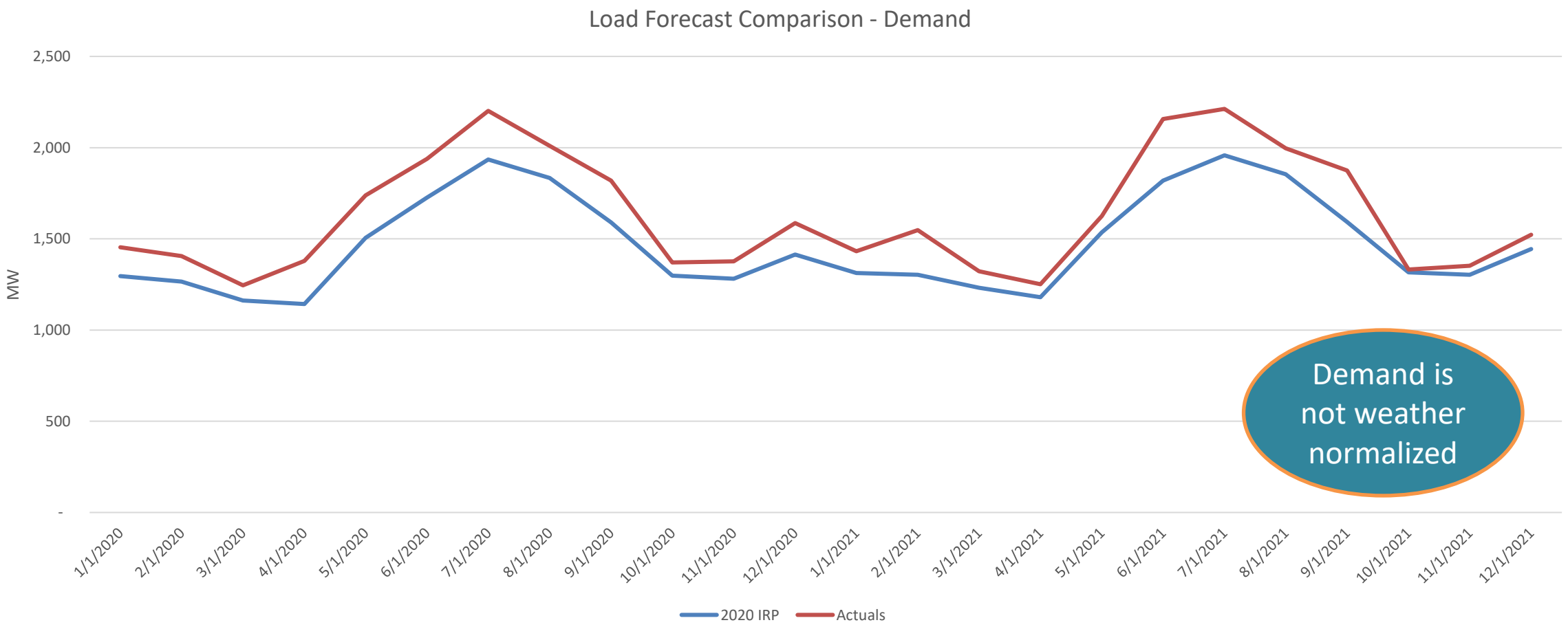
The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

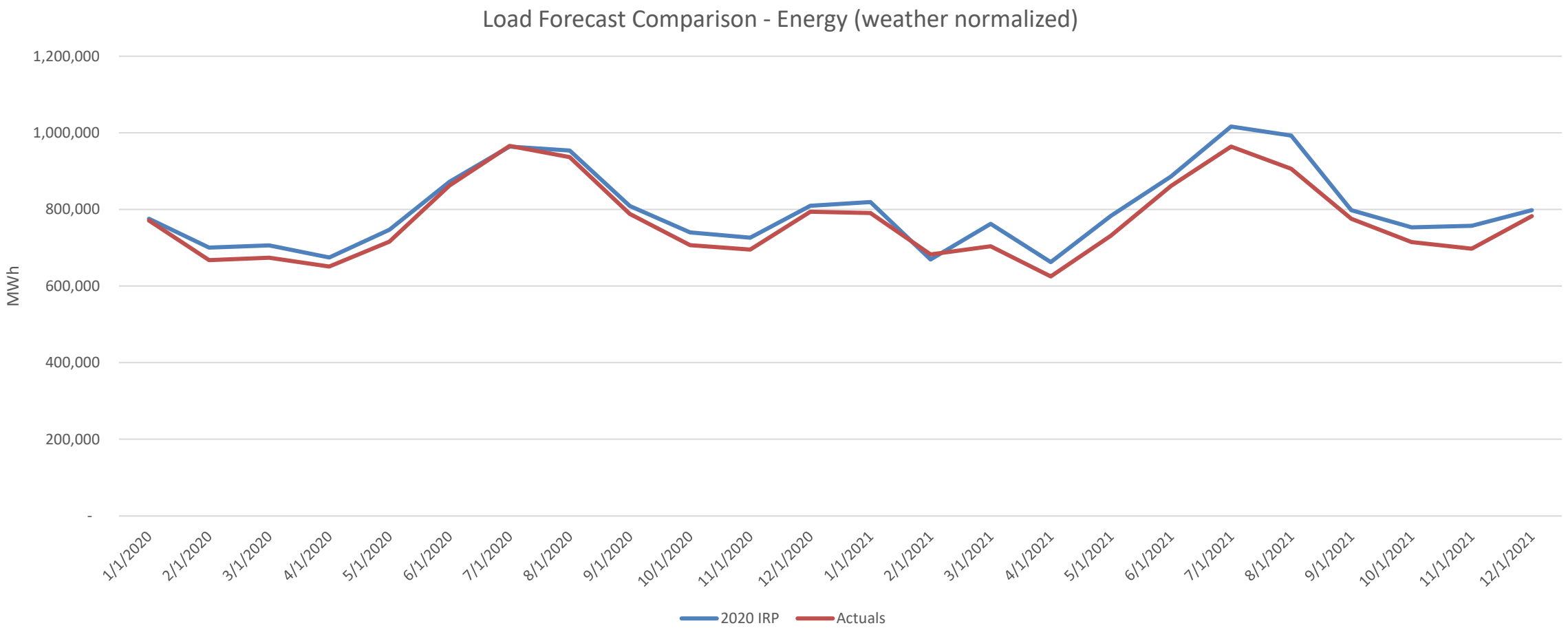
- Welcome and Introductions
- Load Forecasting:
  - Load Forecasting Statement of Work/Fundamentals
  - Open forum for any stakeholder discussion or any changes on assumptions for the load forecasting fundamentals
- Candidate Resource Pricing Methodology
  - Review
  - Feedback/Questions
- Next steps and Near-Term/Long-Term Schedule

2020 IRP LOAD FORECAST COMPARISON TO ACTUALS



Talk to us.

2020 IRP LOAD FORECAST COMPARISON TO ACTUALS



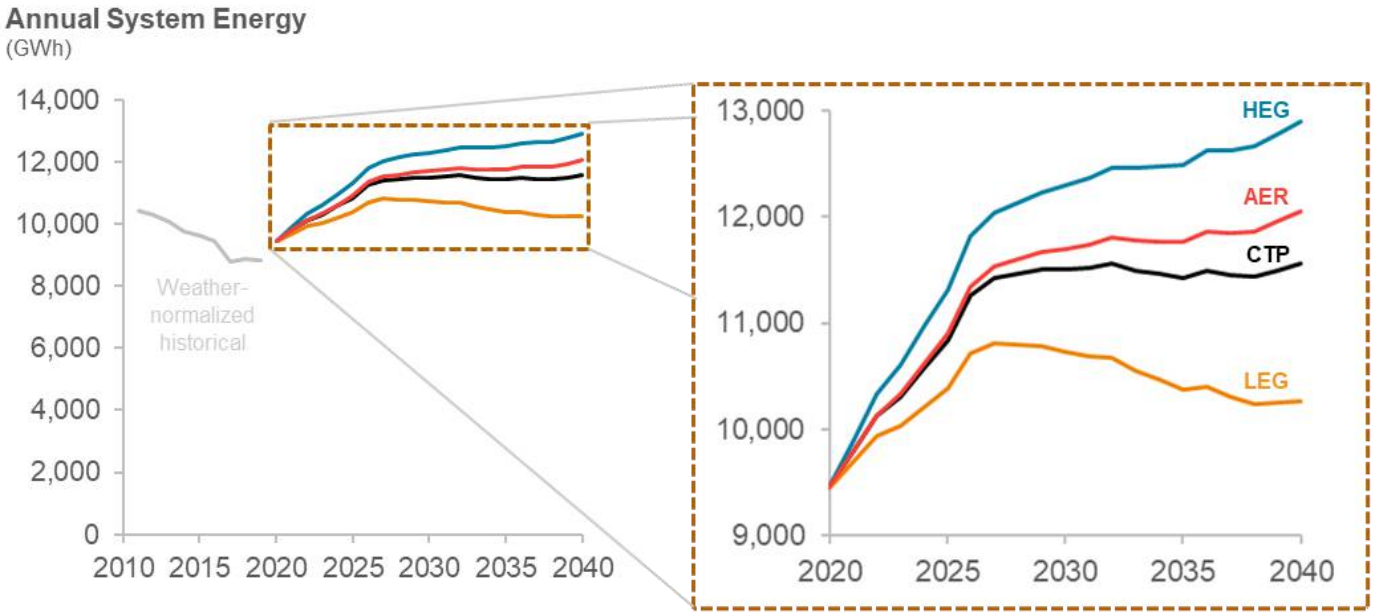
COMMENTS FROM 2020 IRP: QUESTIONED PNM'S LONG TERM LOAD FORECASTING

Comments questioned:

- Historical peak load and energy needs have shown a decline in past decade, but PNM forecast shows incline
- Compounded growth exacerbates and overstates the needs by 2040 timeframe
- PNM not accurately reflecting EE/other factors that show a trending decline

However, the past does not account for economic growth, electrical vehicle adoption rates, etc. and EE was modeled on the supply side.

PNM's 2020 IRP: Figure 40. Forecasts of annual energy demand (before EE reductions) under different futures



CTP = Current Trends & Policy; AER = Aggressive Environmental Regulation; HEG = High Economic Growth; LEG = Low Economic Growth



PNM 2022 IRP Energy and Demand Forecast Status

Stuart McMenamin
David Simons
Itron, Inc.

July 6, 2022

Agenda

- Economic Data and Forecasts
- Weather Data and Normal Weather
- Behind the Meter PV Data and Forecasts
- Electric Vehicle Forecast
- Other Scenario Inputs
- Energy Modeling and Forecasts
  - Customer growth forecast
  - Statistically Adjusted End Use (SAE) Method
  - Use per customer models (energy use vs utility sales)
  - Energy and peak forecast summary
- To Do -- Hourly System Load and Peak Demand Forecasts
  - Bottom-up load shape and peak demand forecast
- To Do -- Forecast Scenarios

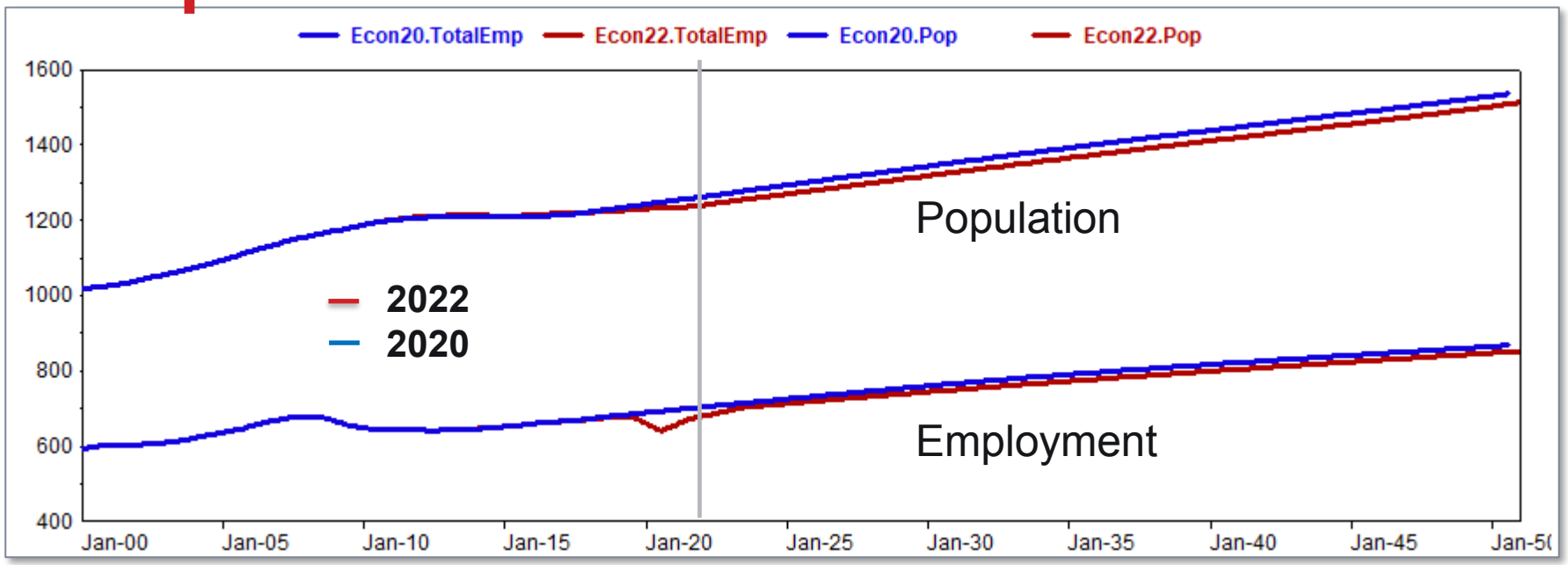
Economic Data and Forecasts

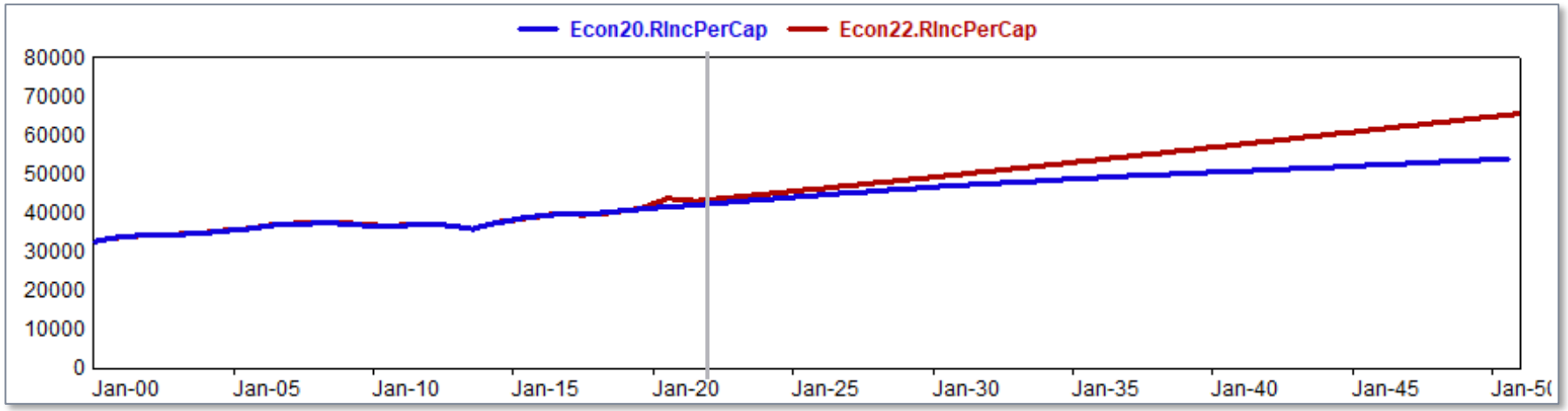
Economic Data and Forecast

- Forecast provided by Woods and Poole
- Annual history from 1950
- Annual forecast to 2060
- State and County level data
- Used data for PNM counties:
  - North: Bernalillo, San Miguel, Sandoval Santa Fe, Union, Valencia
  - South: Grant, Hidalgo, Luna, Otero
- Annual data converted to monthly using centered moving averages
- To Do – Develop High/Low Scenarios



Comparison 2022 vs 2020

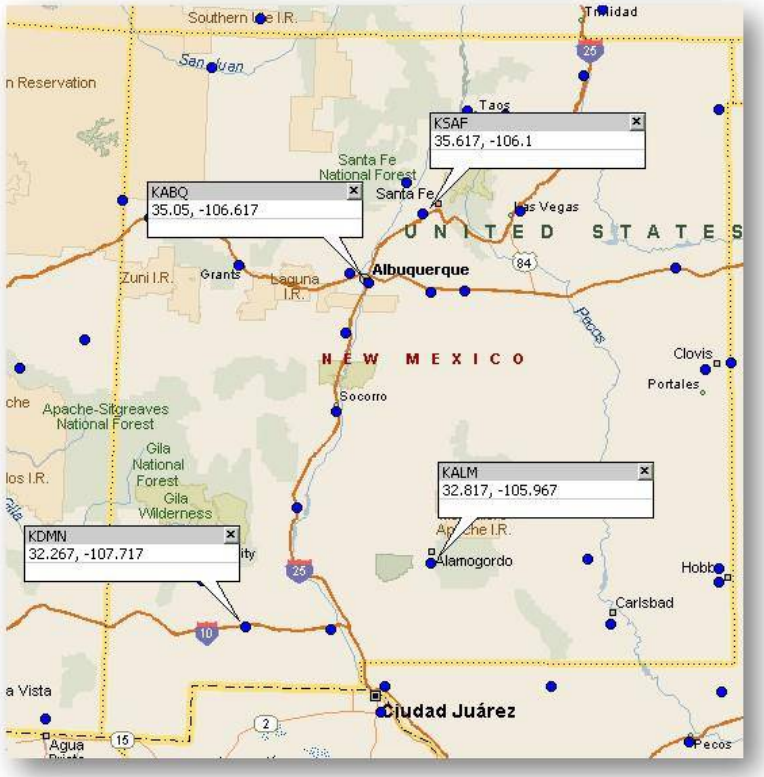




Weather Data and Normal Weather

Weather Data and Normal Scenario

- Hourly weather data from AccuWeather
  - Temperature – Used to compute Degree Days
  - Global horizontal irradiation (GHI) – Used for solar generation
- 4 Stations
  - North: Albuquerque (KABQ), Santa Fe (KSAF)
  - South: Deming (KDMN), Alamogordo (KALM)
- Station weights for weather variables
  - Based on billed sales 2015 to 2018
  - Heating Degree weights based on winter sales
  - Cooling Degree weights based on summer sales
  - Solar GHI weights based on annual sales
- Normal Weather – 2002 to 2021 (20 years)

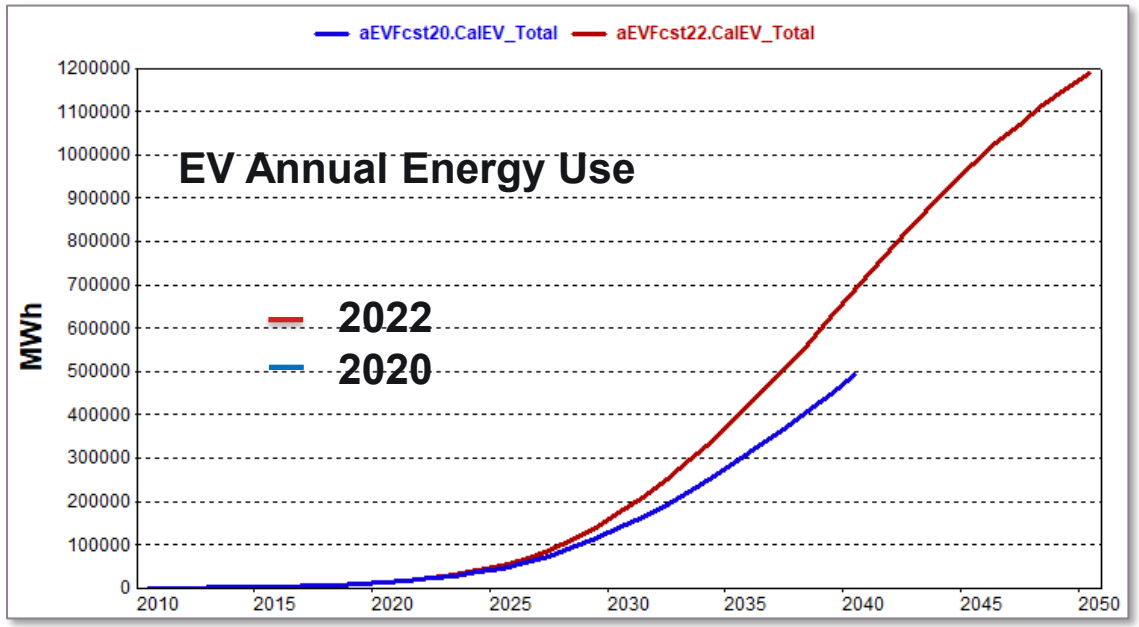


Station	Heating Degrees	Cooling Degrees	Solar GHI
KABQ	75.0%	77.8%	76.3%
KALM	3.0%	3.2%	3.1%
KDMN	9.0%	8.4%	8.9%
KSAF	13.0%	10.5%	11.7%

Electric Vehicle Forecast

ELECTRIC VEHICLE FORECAST

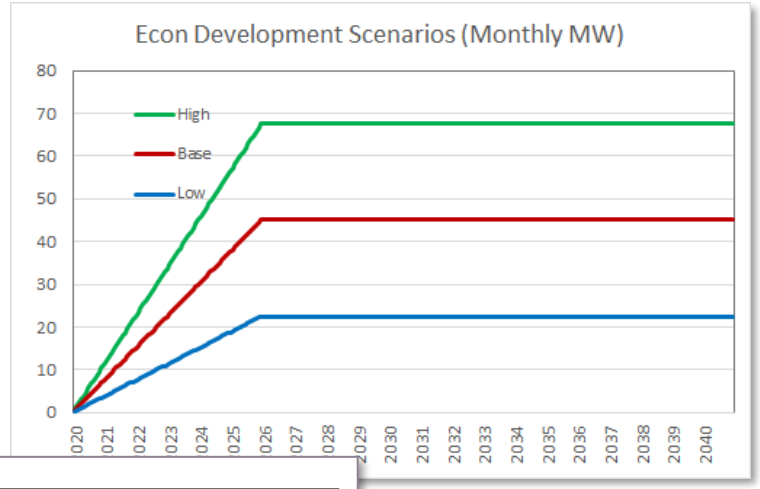
- Forecasts based on new car sales
  - Total New Mexico annual car sales are about 87,000
  - US EV adoption ramps up from 2.3% to 20% by 2030, 35% by 2040
  - NM adoption is about 41% of US adoption
  - 75% of NM adoptions are in PNM territory
  - EV annual energy use is about 4 MWh
  - About 80% of charging is residential
- Changes for 2022
  - Forecasts extended to 2050
  - Car life set to 18 years
- New forecast is stronger by 200 GWH in 2040
- To Do – Develop EV scenarios

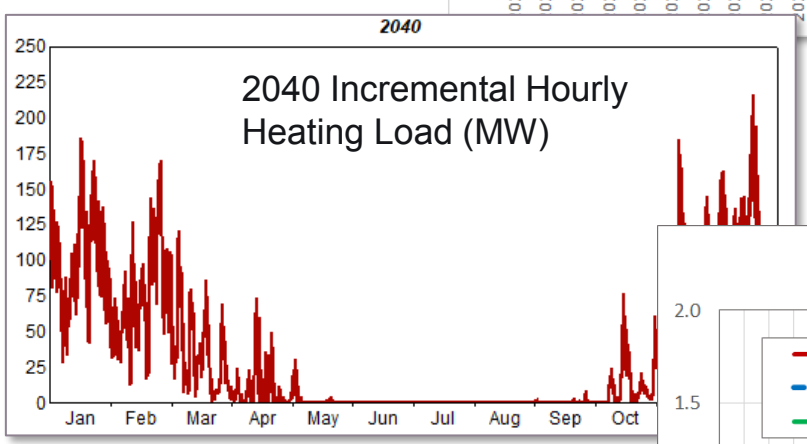


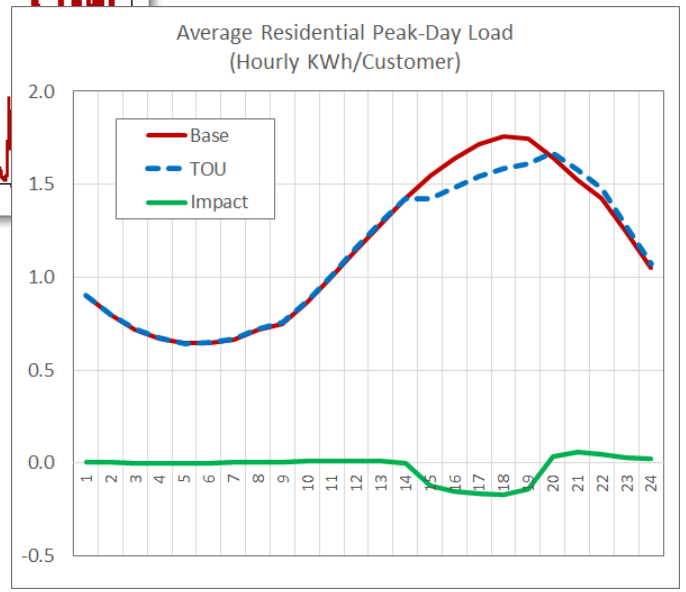
Other Scenario Inputs

Other Factors

- Provided by PNM Economic Development Group
  - Represents new industrial customers
  - Added about 360 GWh to 2020 forecast by 2026
  - To Do – Get inputs for 2022 forecast
- Electrification
  - To Do – Update scenario inputs
- Time of Use Rates
  - To Do – Update scenario inputs



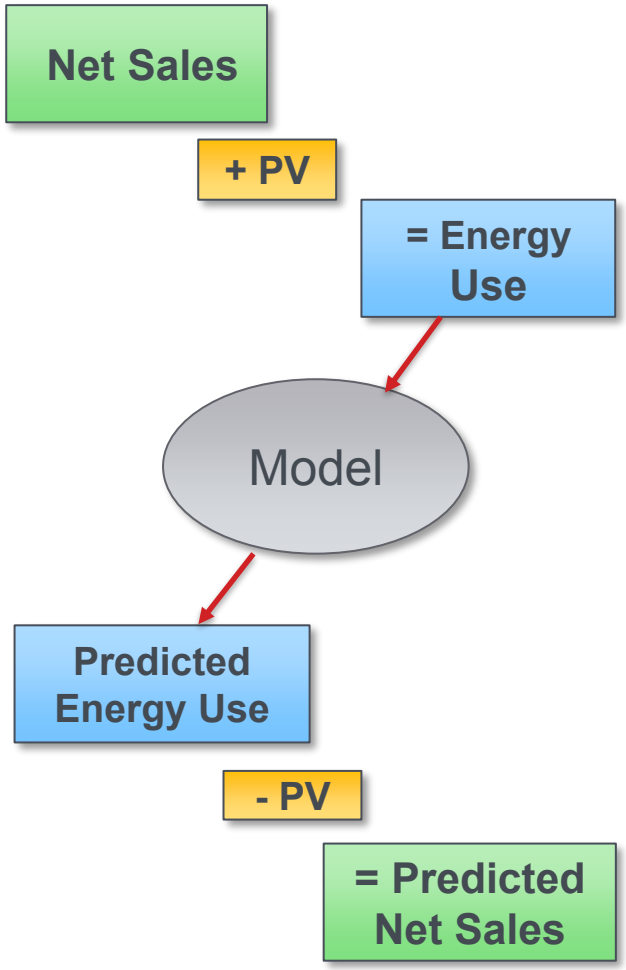




Energy Modeling and Forecasts

Energy Use and Energy Sales

- Monthly sales and monthly energy use:
  - Sales = net delivery of energy through the customer meter
  - Energy use = consumption of appliances and equipment
  - Energy use is bigger than net sales because of PV generation
  - Models explain energy use
- Monthly Use Models
  - Regression models
  - Y is energy use per customer (UPC)
  - X variables are end-use drivers and weighted CD and HD variables
- PNM Sales and Load
  - Sales computed as Energy Use Forecast – PV Generation Forecast
  - Same approach as used in 2020 IRP Forecast

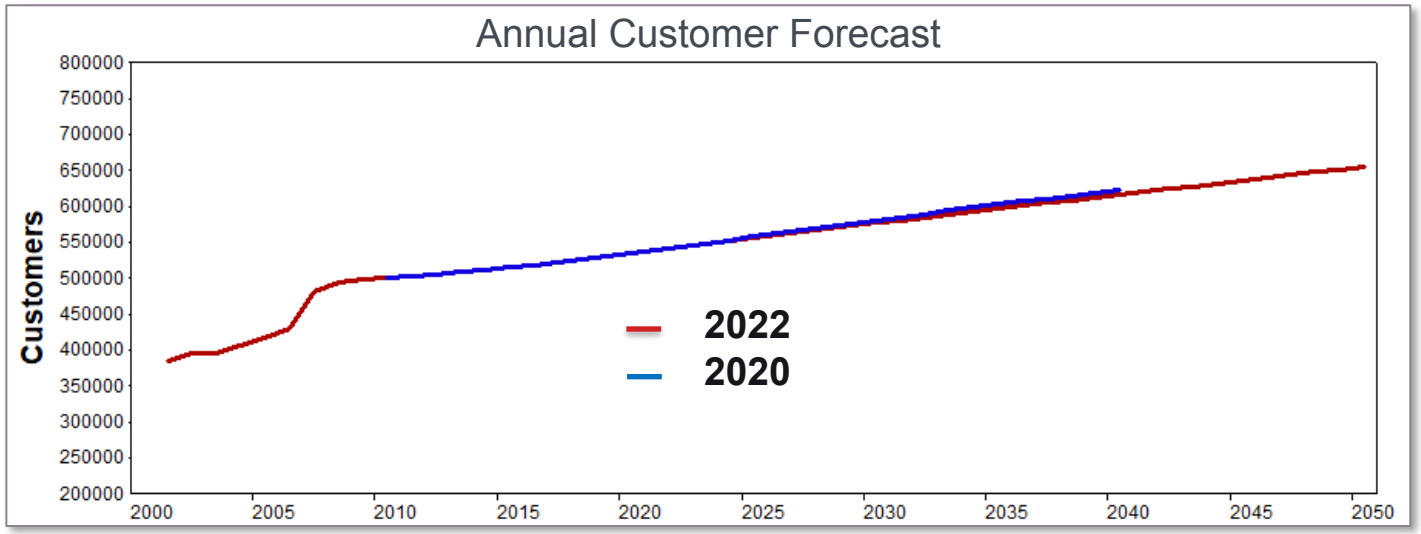


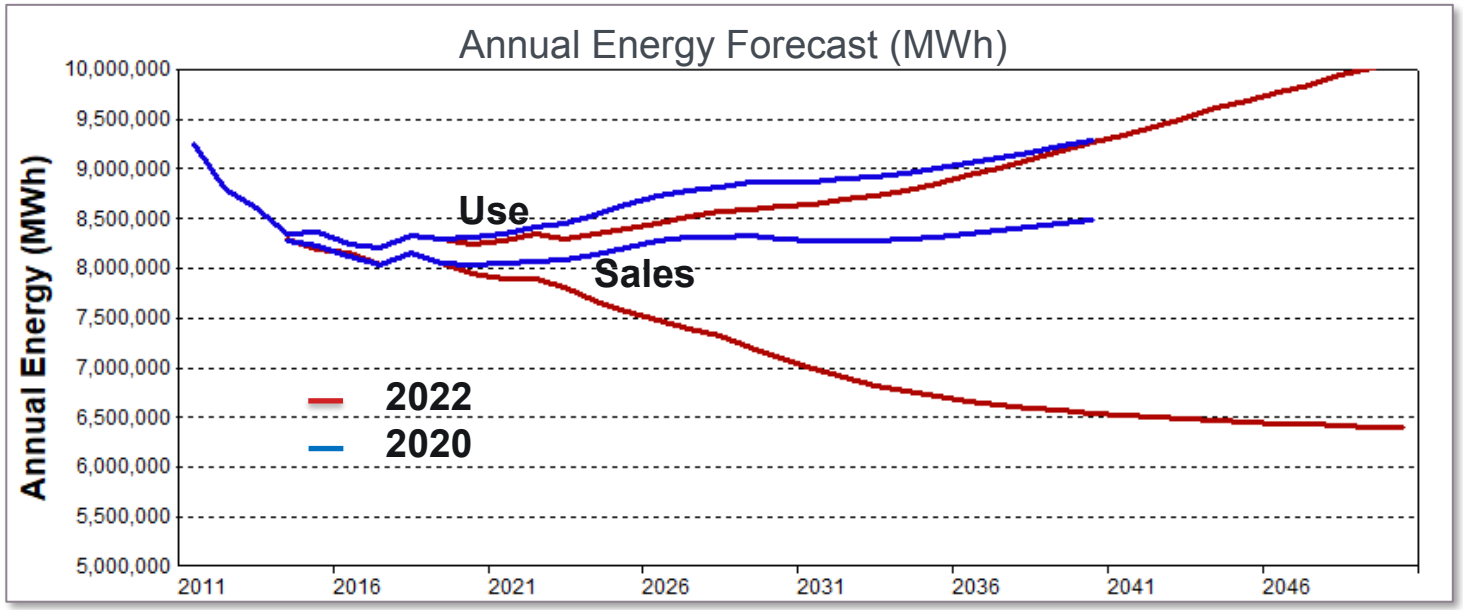
Statistically Adjusted End-Use Framework

- Residential and commercial models use Statistically Adjusted End-Use (SAE) Model
- SAE models account for:
  - Appliance and equipment efficiency
  - Thermal efficiency of buildings
  - Appliance saturation and equipment density
- Efficiency and saturation data initialized using 2021 EIA data for Mountain region
- Saturation and intensity values are modified to agree with PNM data
  - 2016 base-year intensities and saturations from PNM Efficiency Potential Study
  - Efficiency gains are accelerated in 2021 to 2025 to be consistent with PNM efficiency goals and potential study estimates
  - To Do – Update if new market studies are available

COMPARE 2022 DRAFT AND 2020 FORECASTS

- Customer forecast is about the same
- 2022 Use forecast is lower to 2040
  - No Econ Dev in 2022 forecast versus 350 GWh in 2020 forecast through 2026
- Use forecast gap closes by 2040
  - Stronger EV forecast adds 200 GWh by 2040
- Sales forecast is driven downward significantly because of stronger PV adoption in the 2022 forecast

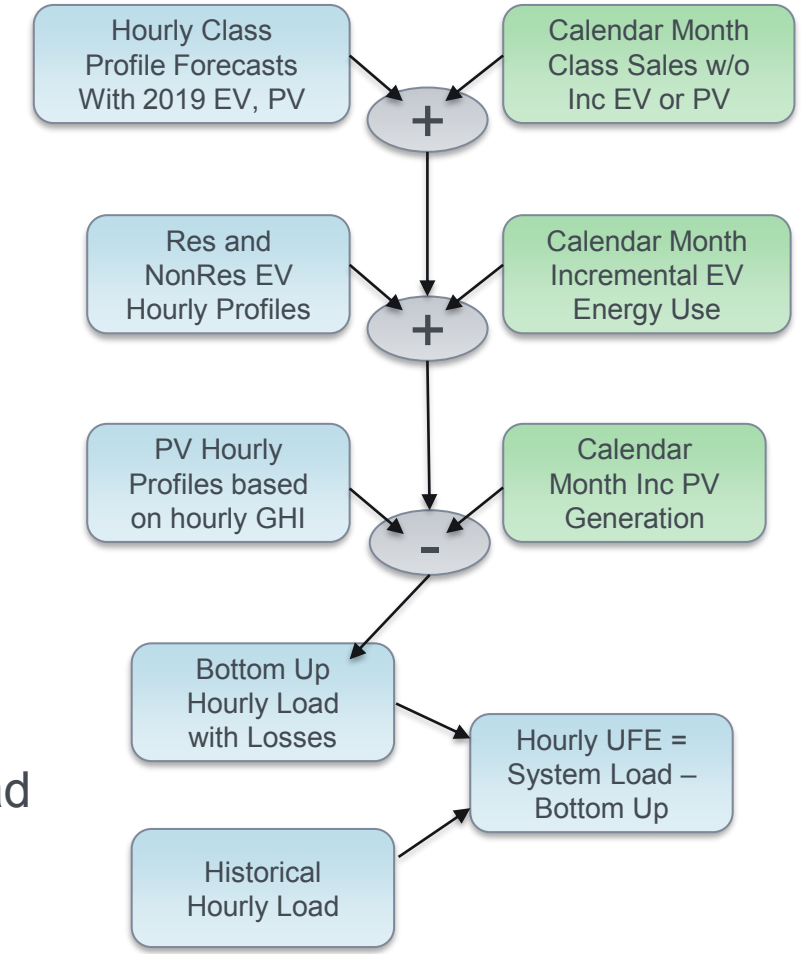




Hourly Load and Peak Demand Forecast

Hourly Load and Peak Load Forecasts

- Hourly load models for each class
  - Estimated with hourly load research data for 2015 to 2019
  - Forecasted using normal daily weather pattern
- Hourly shapes for EV and PV
  - EV shapes: Idaho National Labs, EV Charging Reports
  - PV shapes based on hourly GHI data (rotated from 2018)
- Bottom up logic
  - Calendar month sales forecast without incremental EV or PV
  - Calibrate class hourly profile to calendar month energy value
  - Scale EV profile to incremental EV energy, add to class load
  - Scale PV profile to incremental PV energy, subtract from class load
  - Multiply by annual loss factor based on voltage level
  - Add across classes
- Compute and apply UFE adjustment factors by month and hour



Forecast Scenarios

2020 Scenario Definitions

	Scenario	Economic Forecast	BTM PV	EV Adoption	Building Electrification	TOU	Description
A	Reference Forecast	Mid	Mid	Mid	No	No	Base Forecast without EE Programs
B	High Economics	High	Mid	Mid	No	No	Strong Econ, Misc. End Use, & Econ Dev
C	Low Economics	Low	Mid	Mid	No	No	Weak Econ, Misc. End Use, & Econ Dev
D	Strong Energy Growth	High	High	High	Yes	No	Strong Econ, Misc. End Use, & Econ Dev Strong PV, Strong EV, Add Res Electrification
E	Weak Energy Growth	Low	Low	Low	No	No	Weak Econ, Misc. End Use, & Econ Dev Weak PV, Weak EV
F	High BTM PV	Mid	High	Mid	No	No	Strong PV
G	Low BTM PV	Mid	Low	Mid	No	No	Weak PV
H	Zero Incremental PV	Mid	Zero Inc	Mid	No	No	Zero Incremental PV
I	Zero PV	Mid	Zero	Mid	No	No	No PV Ever
J	High EV Adoption	Mid	Mid	High	No	No	Strong EV
K	Low EV Adoption	Mid	Mid	Low	No	No	Weak EV
L	Aggressive Environmental Regulation	Mid	High	High	Yes	No	Strong PV, Strong EV, Add Res Electrification
M	High Building Electrification	Mid	Mid	Mid	Yes	No	Add Res Electrification
N	TOU Pricing	Mid	Mid	Mid	No	Yes	Add TOU Impacts

THANK YOU

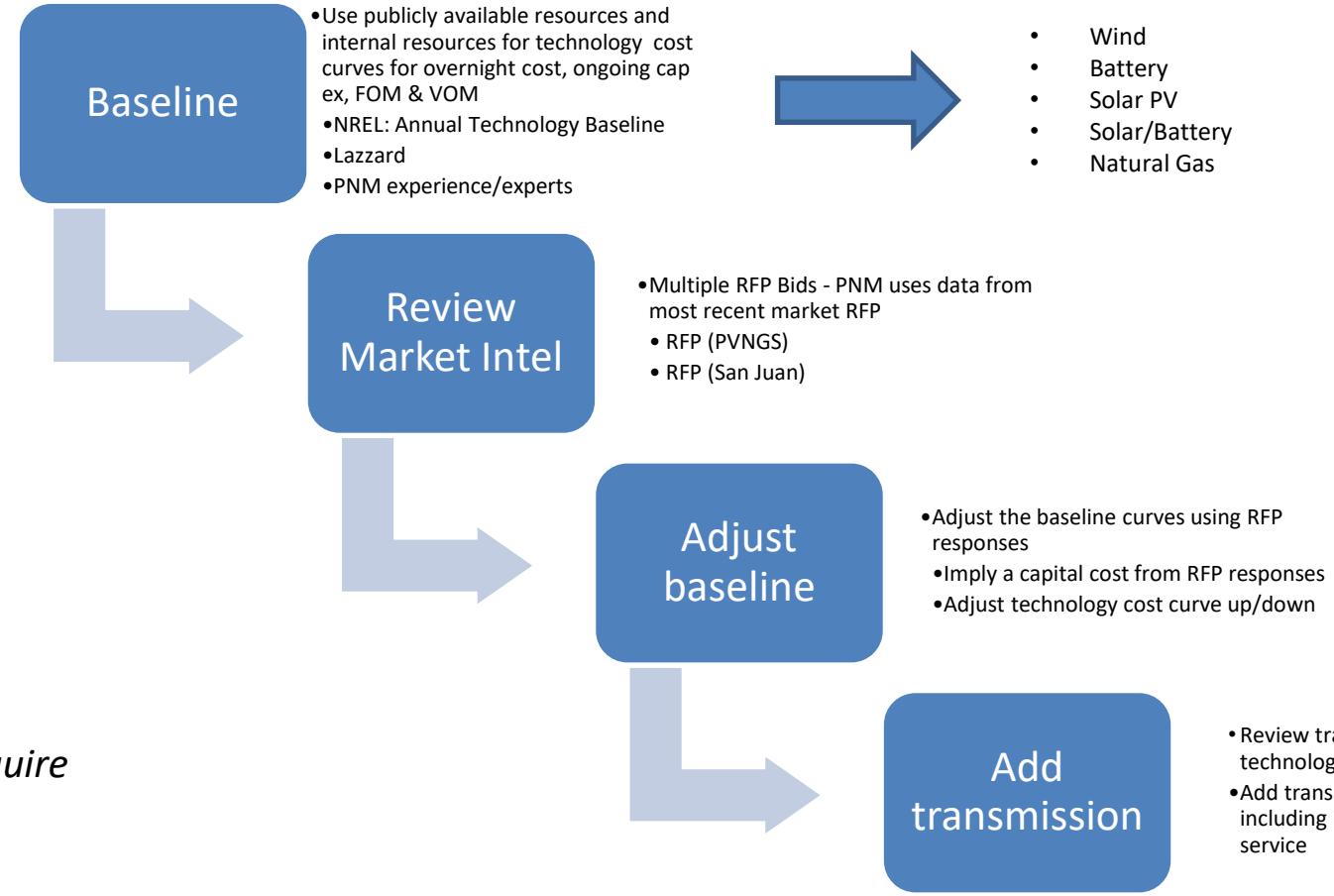
stuart.mcmenamin@itron.com
david.simons@itron.com
forecasting@itron.com

COMMENTS FROM 2020 IRP: CANDIDATE RESOURCE PRICING

Cost assumptions for renewables are too high

- Assumed costs for new wind, solar & battery resources are high above NREL's costs
- PNM lacks transparency in how it uses RFP bid costs to imply a capital cost
- PNM lacks transparency in transmission cost adjustments

CANDIDATE RESOURCE PRICING METHODOLOGY



Not all technologies require adjustments

2023 IRP PUBLIC ADVISORY PROCESS

WE WOULD LIKE TO HEAR FROM YOU

We did not receive any feedback to these questions posted during the last public meeting:

1. What did we do well in the last (2020) IRP and where can we improve?
2. Any additional ideas for technical discussions?
3. What is the proper way to balance reliability, customer cost and accelerating the transition to clean energy?
4. How can we be more collaborative throughout the process with our public stakeholders?

We would also like to hear your ideas on the Load Forecasting Scope of Work or the Candidate Resource Pricing Methodology or if you have any questions.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: July 27, 2022

Topic: Public Advisory Technical Session #4: IRP Modeling Updates/Techniques & *Preliminary RFI Responses

Start Time: 9:00 AM

Location: Virtual

Subject to change, pending time constraints

Due to many participants for the first two meetings attending virtually, we have decided to make the next meeting a virtual meeting. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: August 3, 2022

Topic: Public Advisory Technical Session #5 (Modeling Assumptions: Transmission*)

Start Time: 9:00 AM

Location: Virtual

subject to change, may be switched with Public Advisory Group Day on Aug 17

Due to the vast majority of participants for the first two meetings attending virtually, we have decided to make technical session a virtual meeting. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

LONG TERM SCHEDULE (THROUGH 2021)

Date	Meeting		Title
4/28/2022	Steering Meeting #1	Modeling Assumptions/ Drivers	IRP Kick Off Meeting
5/25/2022	Steering Meeting #2		Reliability & Resiliency
6/8/2022	Technical Session # 1		*Resource Adequacy Modeling*
6/22/2022	Mini Steering/Technical #2		*Energy Efficiency/Resiliency/Market Depth*
7/6/2022	Technical Session #3		***Load Forecast/Candidate Resource Pricing Methodology***
7/27/2022	Technical Session #4		***IRP Modeling Updates/Techniques & RFI Responses****
8/3/2022	Technical Session #5		***Other Modeling Assumptions****
8/17/2022	Steering Meeting #4		***Public Advisory Group Day****
8/30/2022	Steering Meeting #5		***Emerging/Evolving Grid Solutions***
9/21/2022	Steering Meeting #6	Modeling Inputs/Set Up	***Modeling Input #1 - Existing System/Inputs***
10/11/2022	Steering Meeting #7		***Modeling Input #2 Scenario Building/The Future***
11/15/2022	Steering Meeting #8		***Modeling Input #3***
12/13/2022	Steering Meeting #9		***Modeling Input #4 Transmission***

**subject to change*

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by July 20, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Modeling Updates

TECHNICAL SESSION #5

JULY 27, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

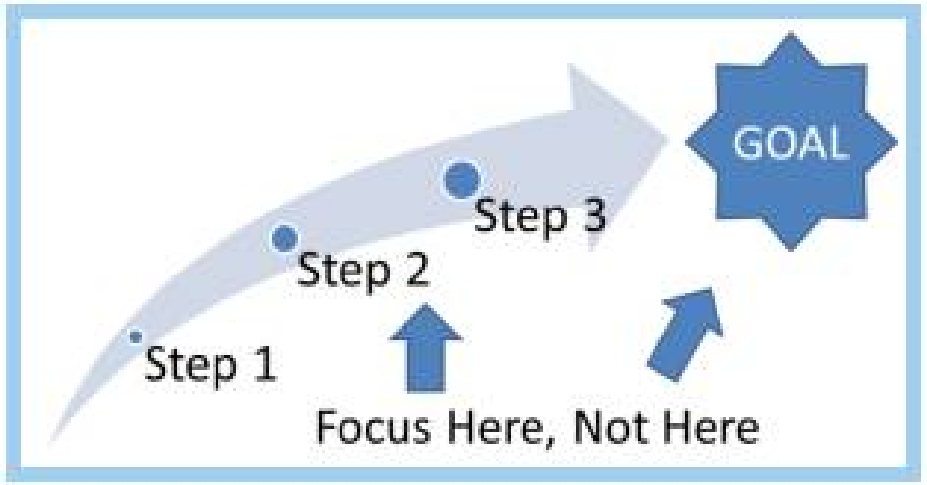
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

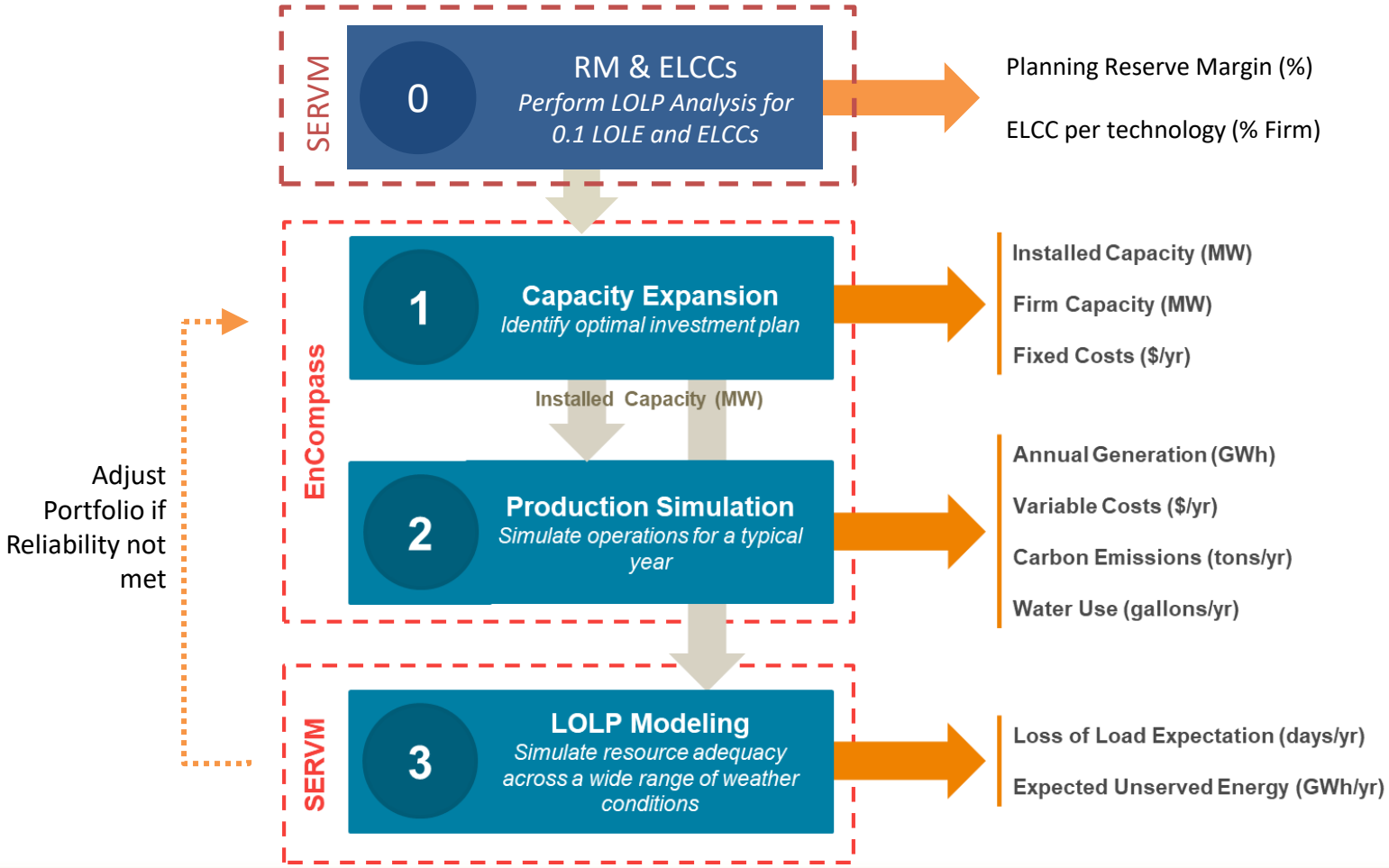
MEETING AGENDA

- Welcome and Introductions
- Modeling Improvements & Testing
- Next steps and Near-Term Schedule

Modeling Improvements and Testing

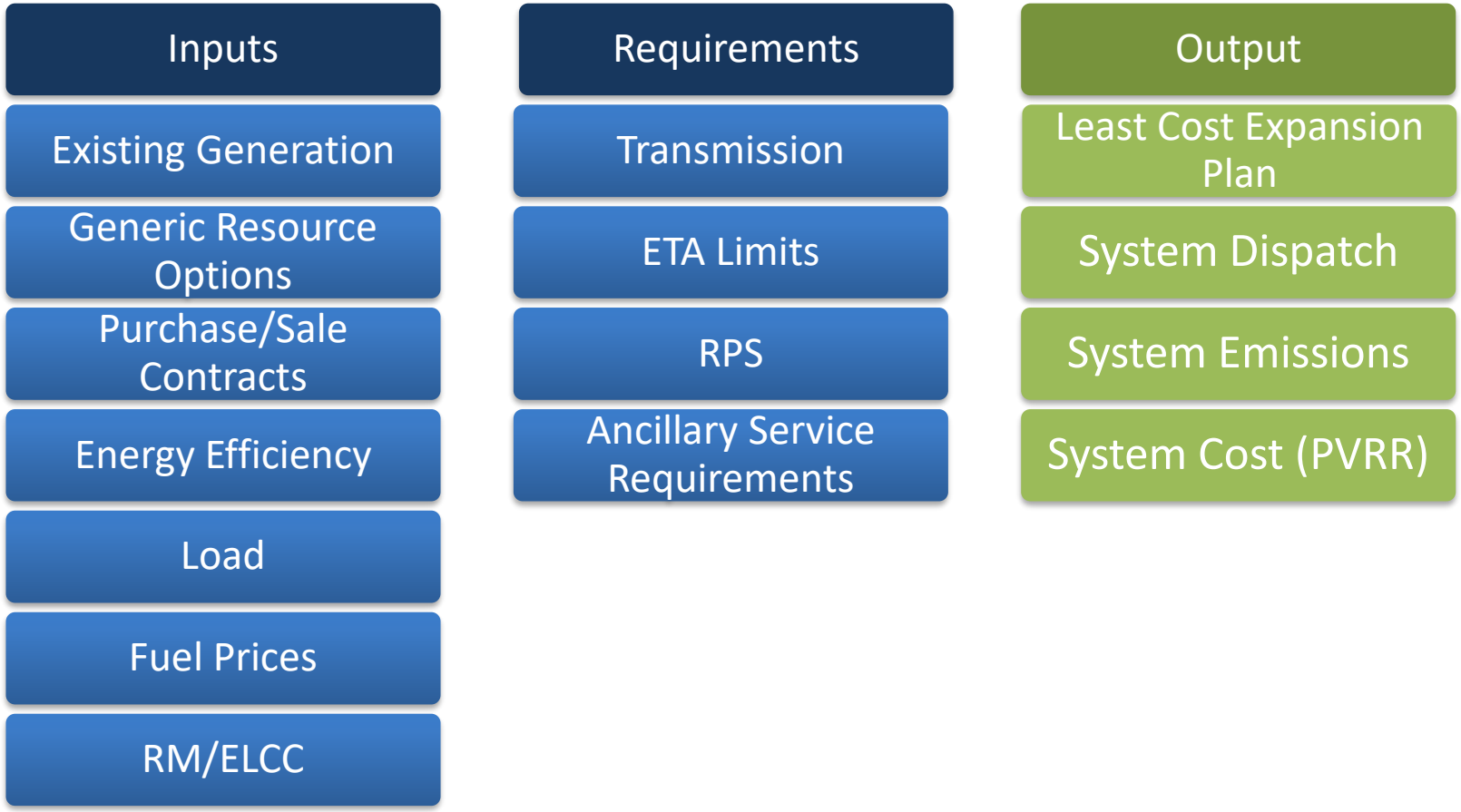
- **Modeling Framework**
- **Performance**
- **Energy Efficiency Modeling**
- **Long Term Storage**
- **Power to Hydrogen**

MODELING FRAMEWORK

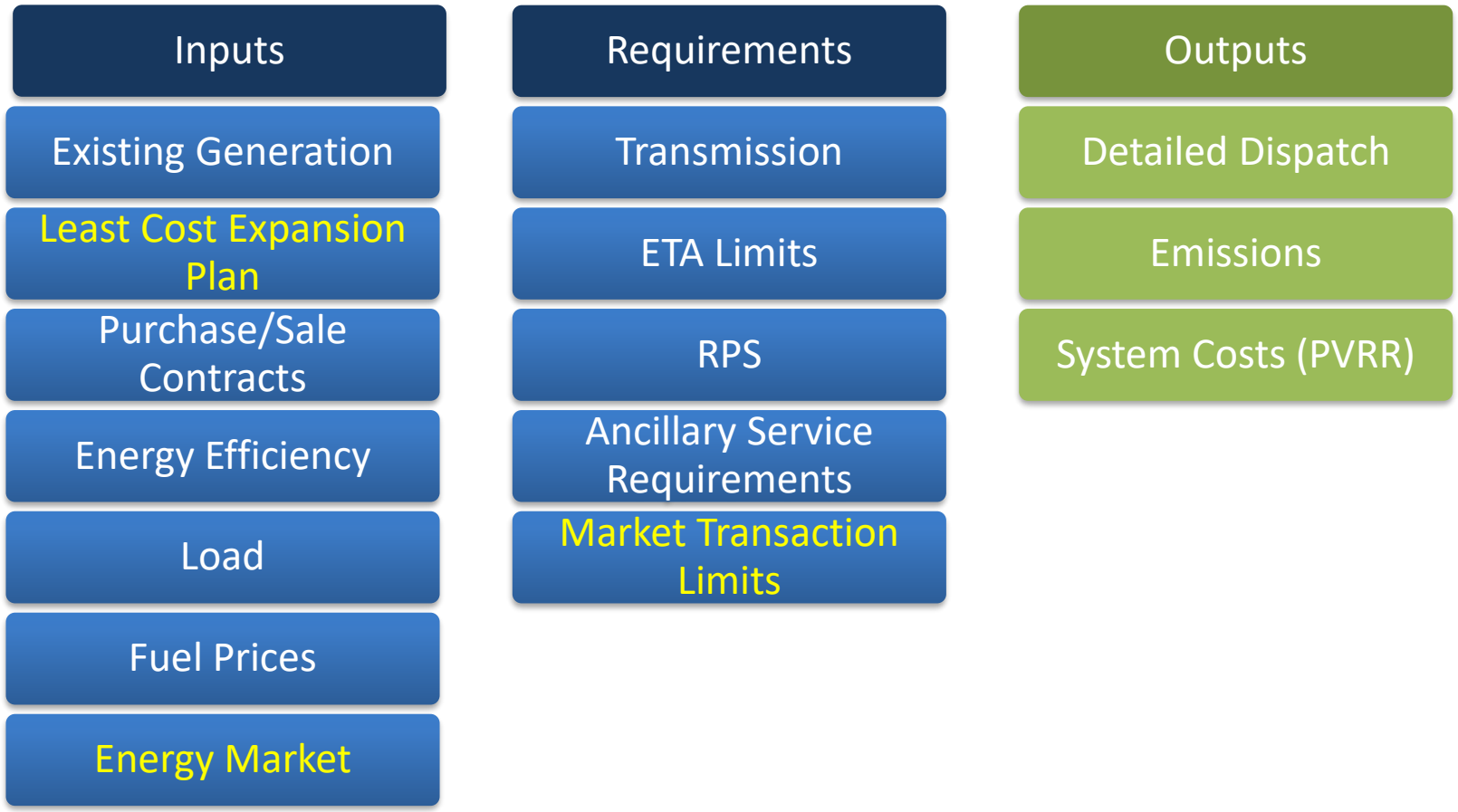


PNM Talk to us. PNM.com

PNM SYSTEM MODELING – CAPACITY EXPANSION



PNM SYSTEM MODELING – PRODUCTION COST MODELING

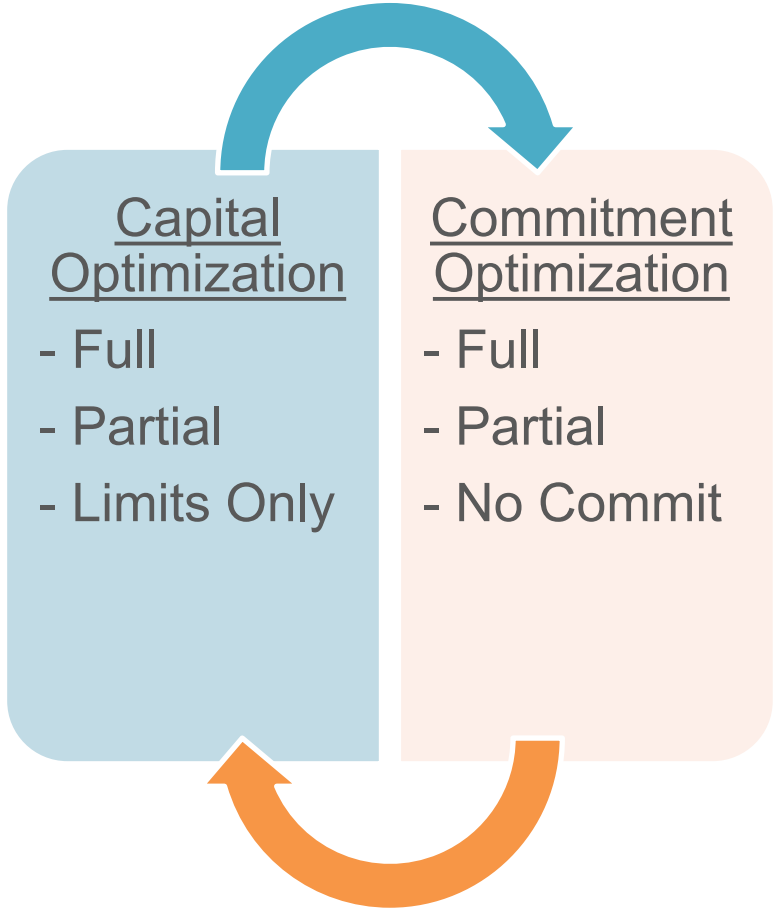


ENCOMPASS MODELING FOR PERFORMANCE

Maximize commitment and dispatch detail of existing and new resources within simulations



Minimize time to perform detailed simulations to allow more time for additional scenarios/and or in-depth analysis



ENCOMPASS MODELING FOR PERFORMANCE - COMMITMENT

No Commitment

Enforced
- Ramp rates
- Ancillary requirements (spin)

Ignored
- Min Capacity (non-must-run)
- Regulation (min/max range)
- Min Uptime/Downtime

Estimated
- Starts/Shutdowns

Best For:
- Scenario Capacity Expansion Planning

Partial Commitment

Enforced
- Starts/Shutdowns (fractional, i.e., 0.4 units = 1 unit @ 40%)
- Ramp rates
- Ancillary requirements (spin)
- Regulation (min/max range)
- Min Uptime/Downtime

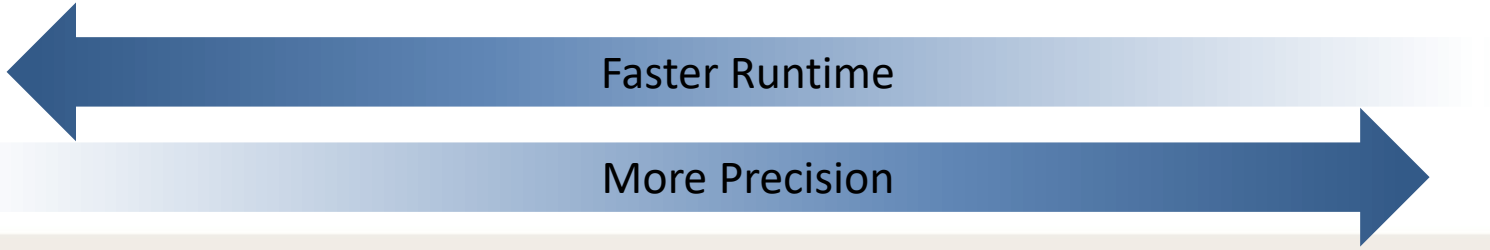
Ignored
- Min Capacity (non-must-run)

Best For:
- Scenario Production Cost Modeling (Annual/Monthly)
- Annual Emission Limits

Full Commitment

Enforced
- Starts/Shutdowns (integer)
- Ramp rates
- Ancillary requirements (spin)
- Min Capacity (non-must-run)
- Regulation (min/max range)
- Min Uptime/Downtime

Best For:
- Hourly Production Cost/Dispatch



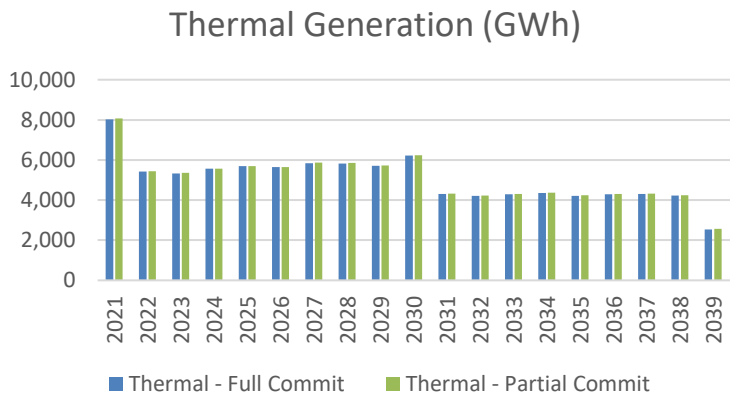
ENCOMPASS MODELING FOR PERFORMANCE - COMPARISON

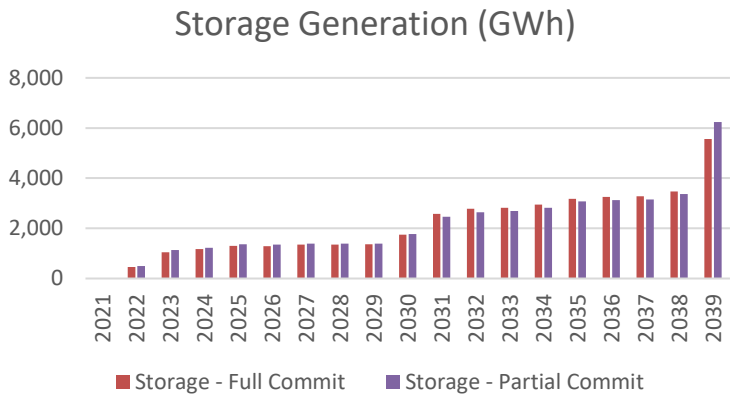
Time taken per simulation/scenario/sensitivity

Run Type	No Commitment	Partial Commitment	Full Commitment
Capacity Expansion	1-2 Hours	5-10 Hours	unachievable
Production Cost – Emission Limit Constrained	15-60 Minutes	45 Minutes to 4 Hours	4-10 Hours
Production Cost – with Existing Emission Limits	~1 Hour	1-2 Hours	1-3 Hours

ENCOMPASS MODELING FOR PERFORMANCE - RESULTS

- Partial Commitment runs can be used for Capacity Expansion simulations and high-level scenario production cost modeling
- Simulation testing has shown that using Partial Commitment is within 2% of the dispatch of the Full Commitment in production cost simulations
- Full Commitment dispatch should be reserved for detailed analysis and hourly production cost results





Talk to us.

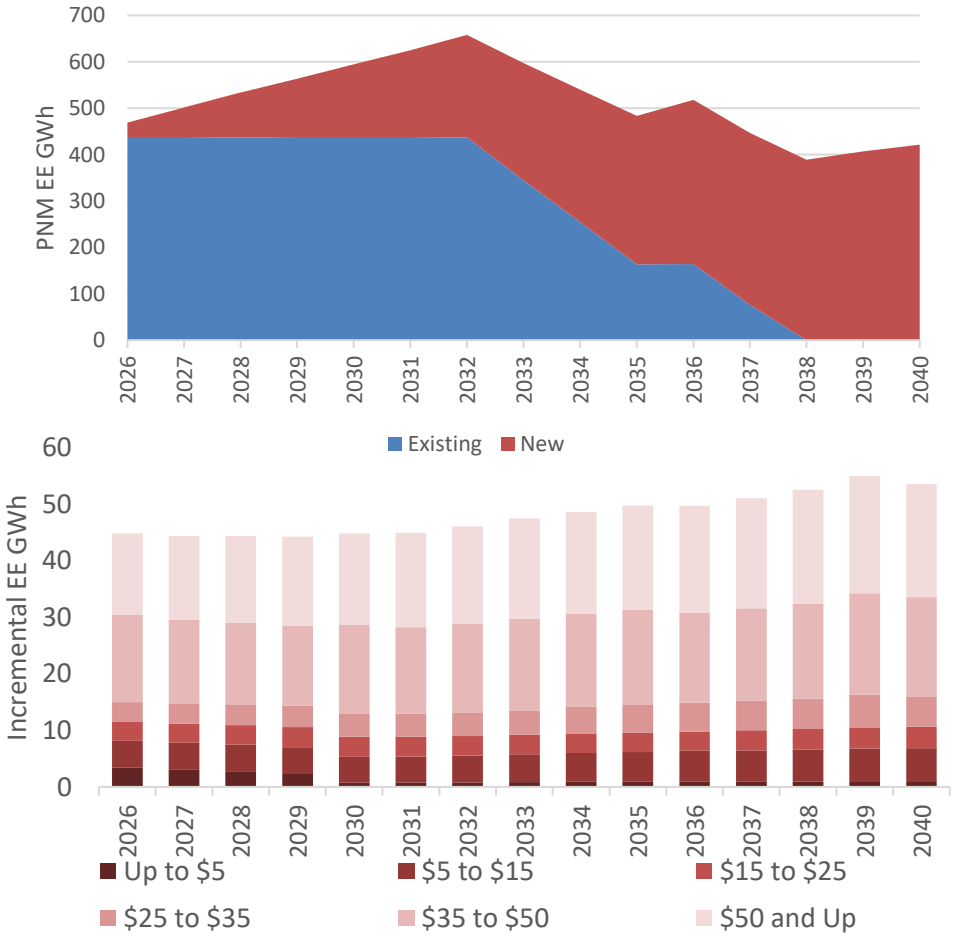
ENERGY EFFICIENCY MODELING IN ENCOMPASS

2020 IRP EE Modeling

- Modeled existing EE programs as existing resources
- New EE programs (EE Bundles) modeled as candidate resources

2020 IRP EE Candidates

- 6 Energy Efficiency Bundle Pricing levels
- Fifteen Different Start Years
- 90 Total Hourly Profiles
- Allowing all bundle options



Talk to us.

ENERGY EFFICIENCY BUNDLES IN 2020 IRP LEAST COST PLANS

Program and Cost	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Base Program	100%	100%	100%	100%	100%															
Incremental Up to $50				99%	100%															
Incremental Up to $5						100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Incremental $5 to $15						100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Incremental $15 to $25						100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Incremental $25 to $35						100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	99%	100%
Incremental $35 to $50						99%	100%	100%	99%	99%	100%	99%	100%	100%	100%	100%	99%	100%	99%	99%
Incremental $50 and Up				0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

ENERGY EFFICIENCY MODELING IN ENCOMPASS

2023 IRP Option A

- Energy Efficiency Bundle Pre-solve
- Pursue Similar Setup as 2020
  - ➢ Run EE Bundles for Low, High, and Base Load Scenarios
  - ➢ Use the Selected Bundles in All Future Scenarios

2023 IRP Option B

- Reduced Energy Efficiency Bundles
- Consolidate Energy Efficiency Bundles into Two or Three Price Options

2023 IRP Option C

- Pursue similar analysis that was performed in 2020 IRP (run all bundles for all scenarios)
- Do not apply prevalent bundles to scenarios
- Do not consolidate bundles

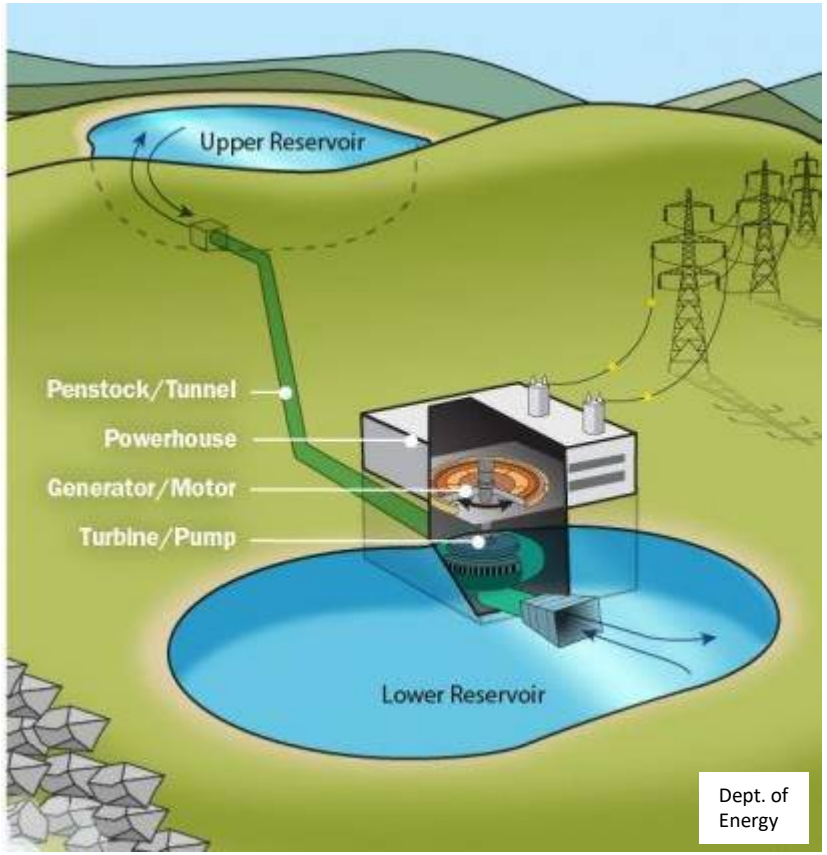
LONG DURATION STORAGE

- Objective is at least one week of Storage for Renewable Energy
- Pumped Storage
- Hydrogen Storage
- Battery Storage
    - Evaluating the value of duration vs capacity
    - Reviewing generic pricing and technology updates

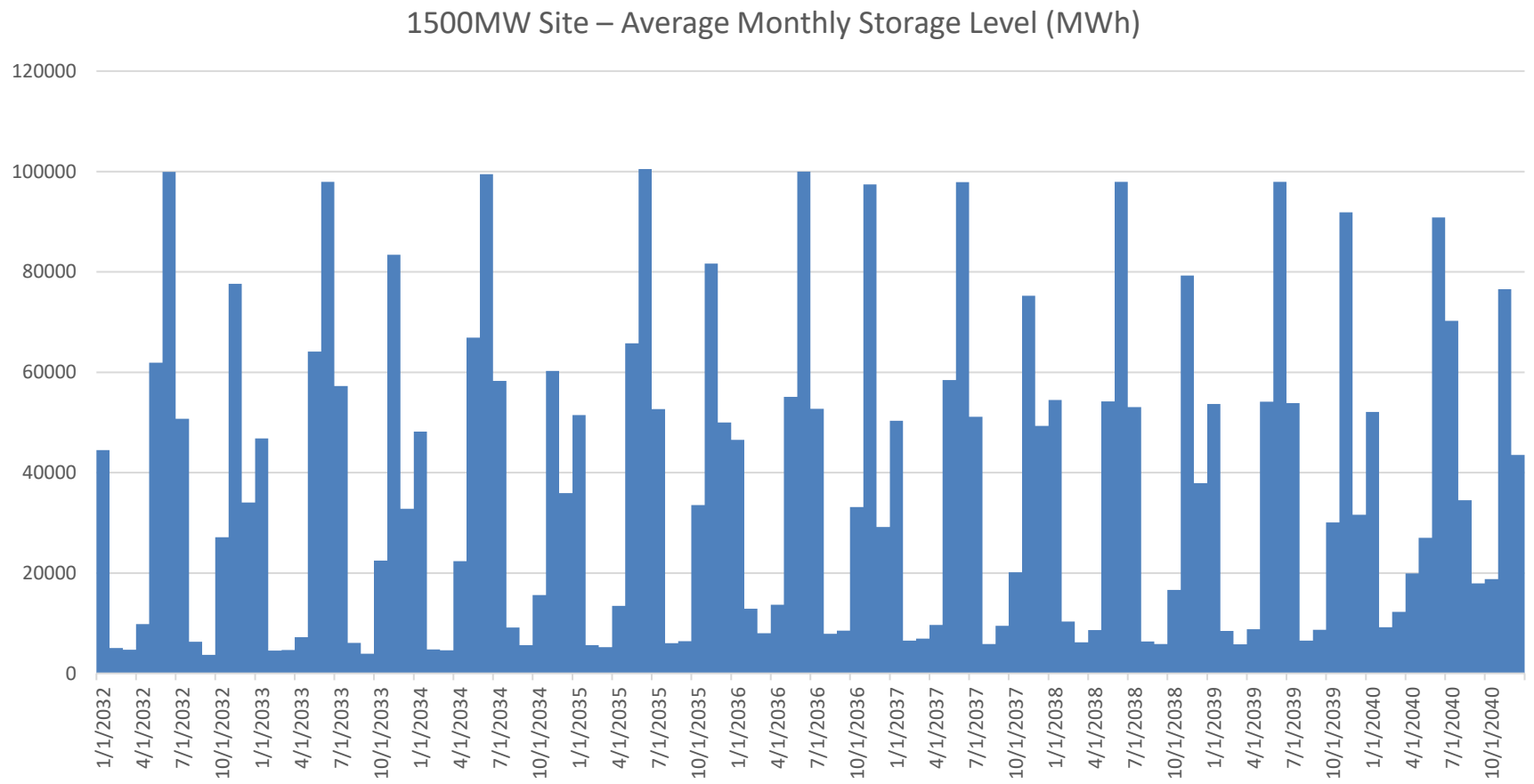
PUMPED STORAGE

Modeling for various configurations

1500MW Capacity
100GWh Energy Storage



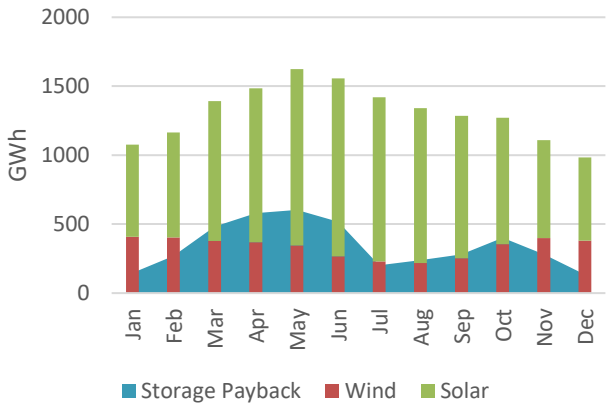
PUMPED STORAGE

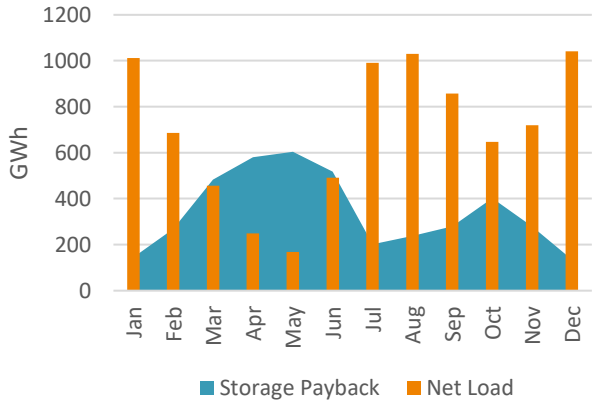


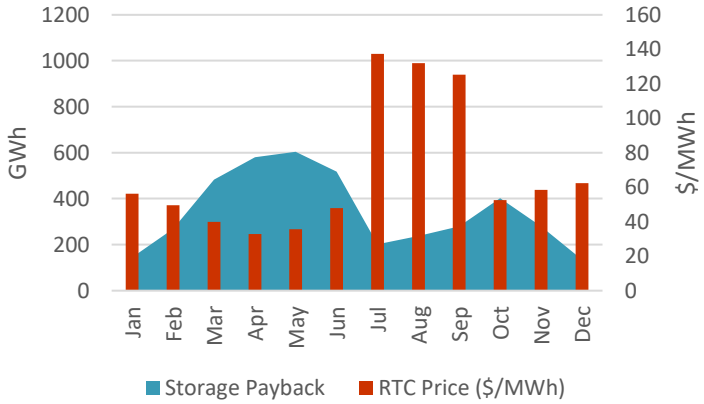
LONG TERM STORAGE

Seasonal Storage Drivers

- Excess Solar/Wind
- Load Requirements
- Seasonal Price Differential

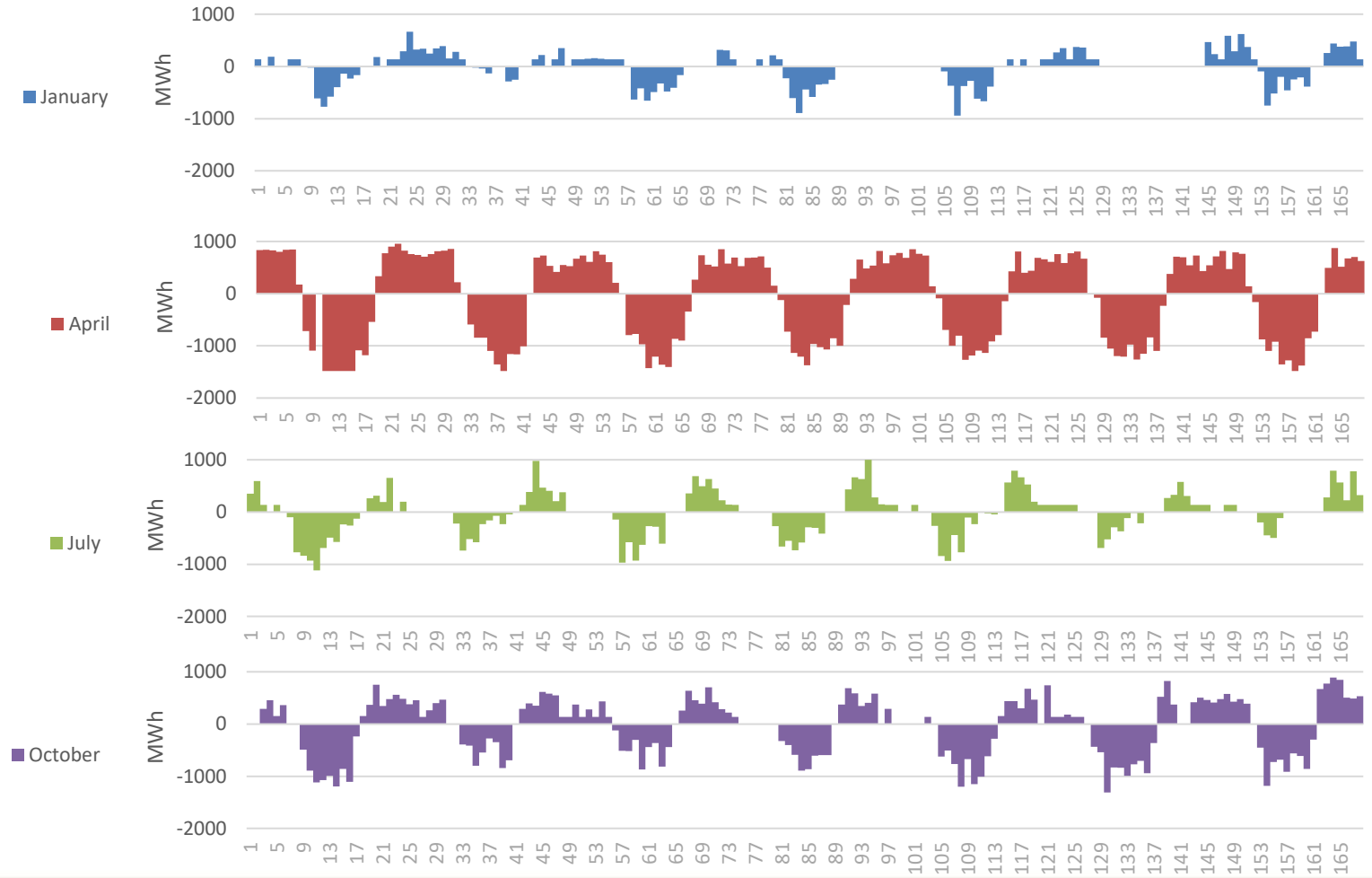






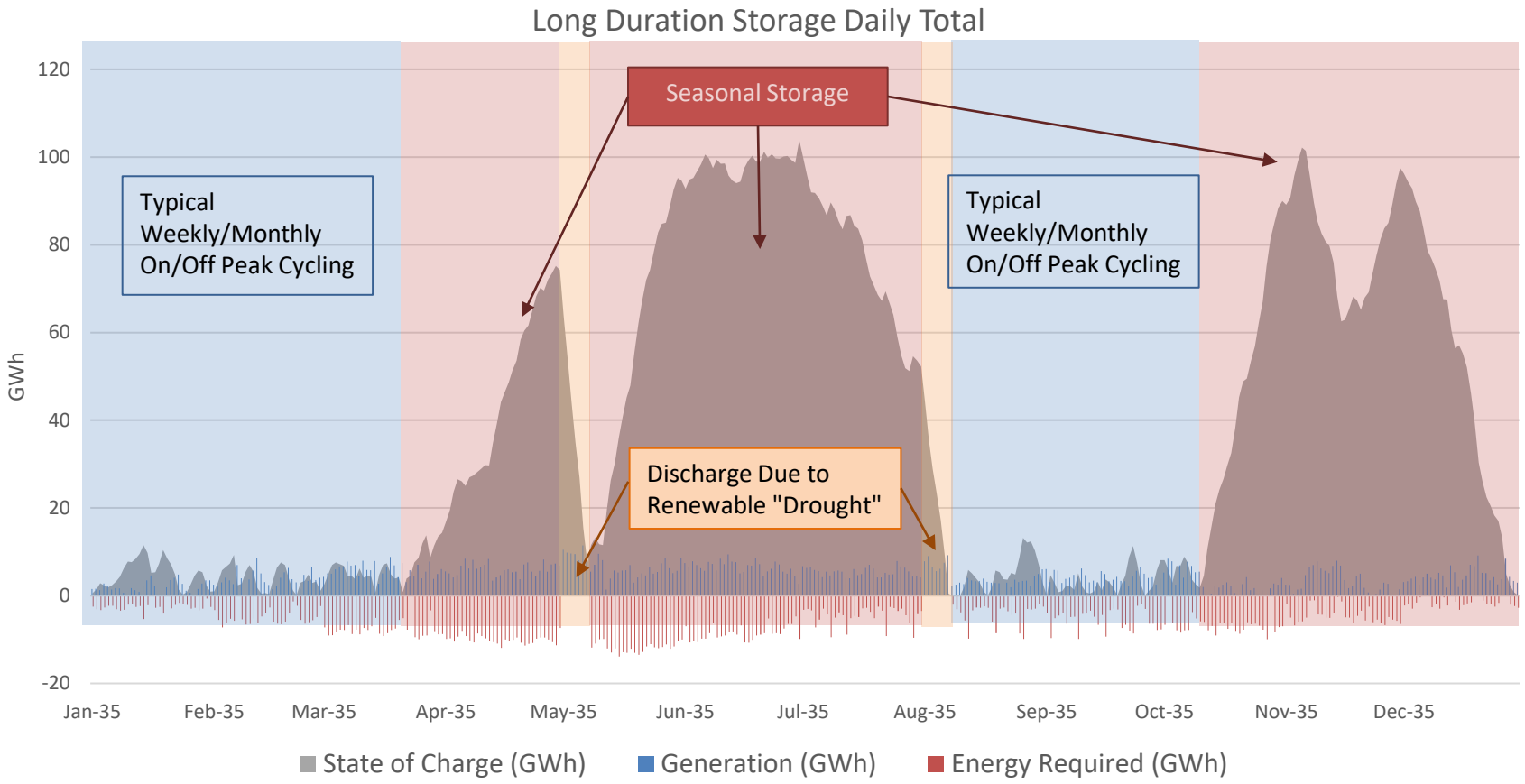
Talk to us.

PUMPED STORAGE – TYPICAL WEEK 2035



Talk to us.

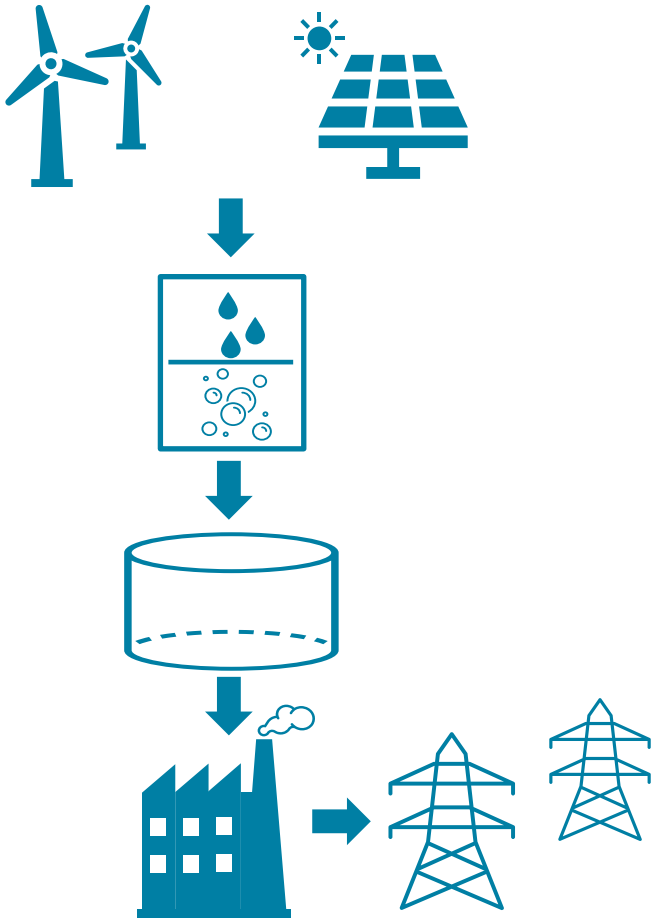
PUMPED STORAGE



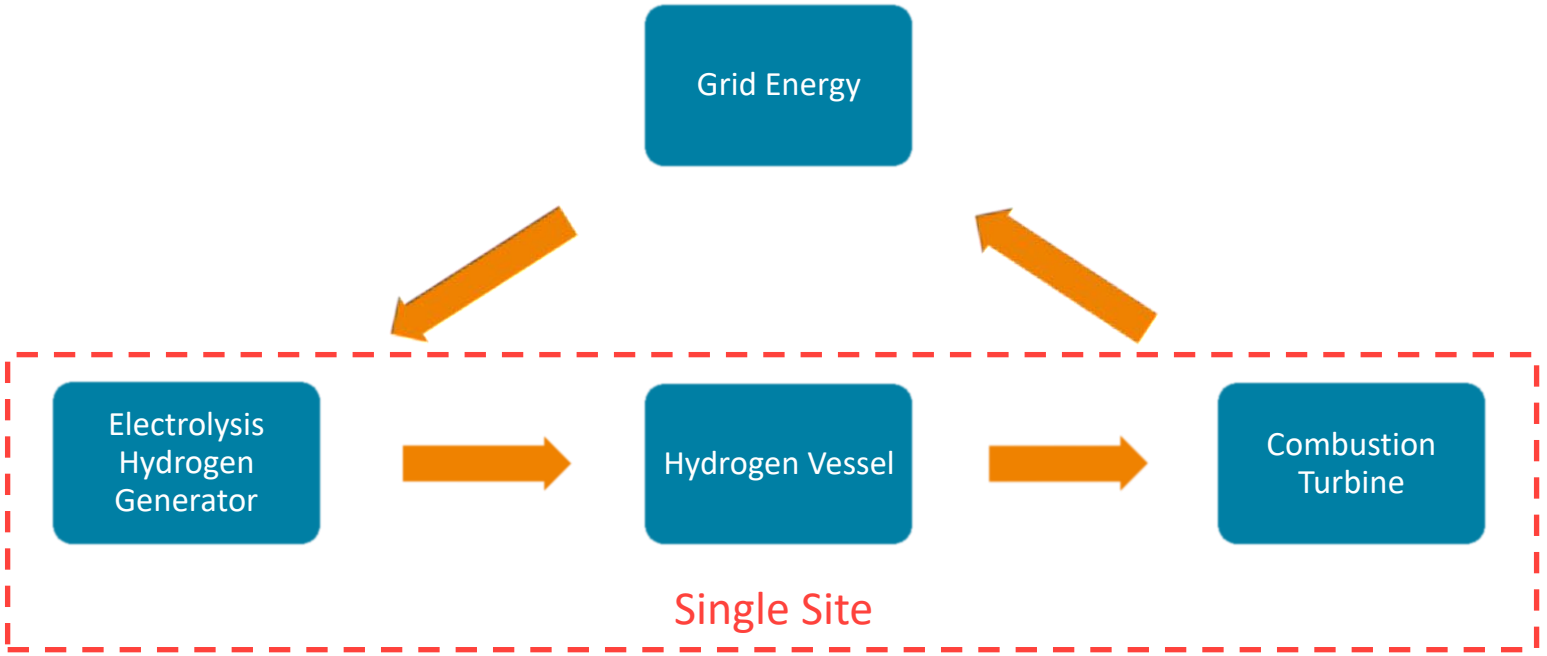
Talk to us.

POWER TO HYDROGEN

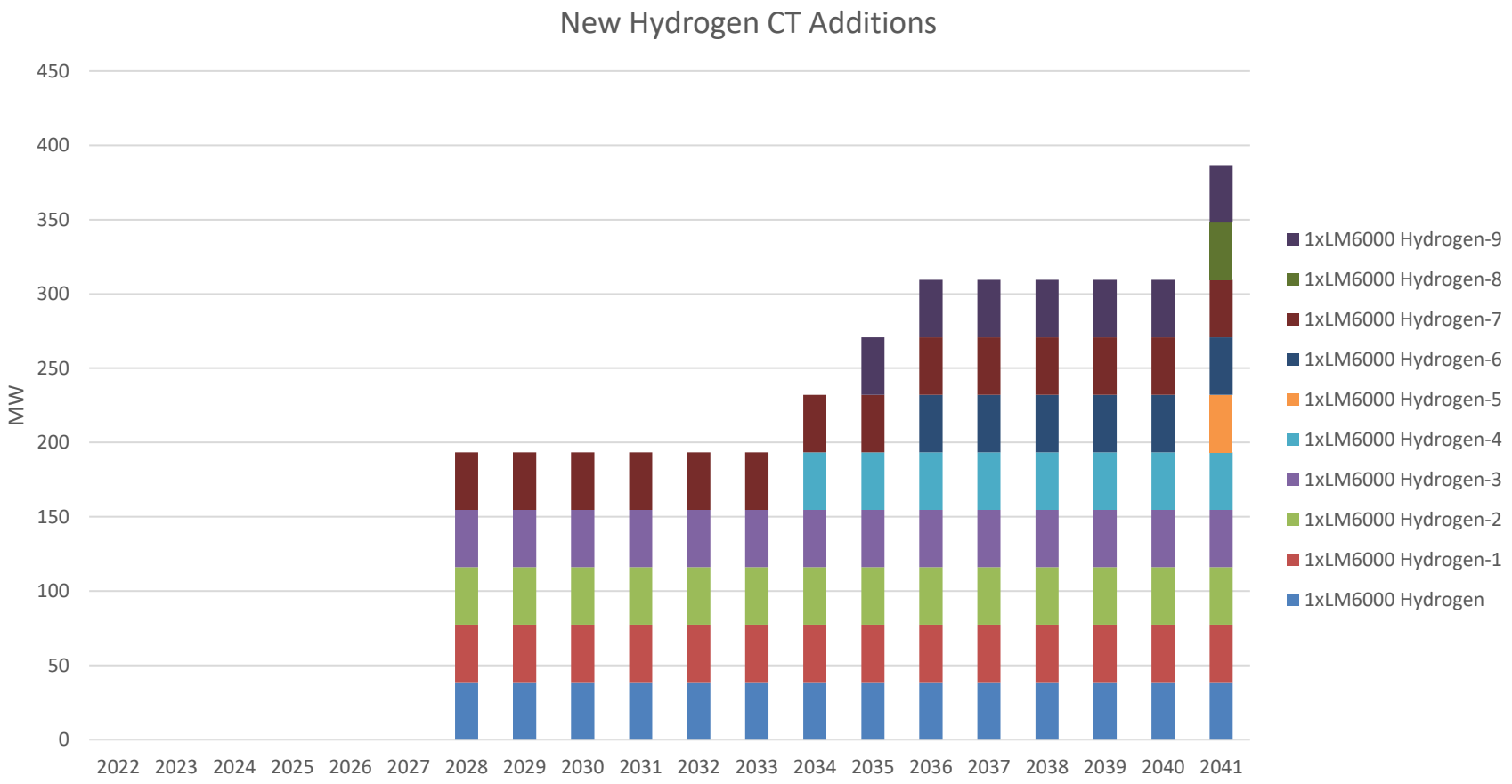
- Single Site Hydrogen Electrolysis, Storage, and CT
- Distributed Hydrogen Electrolysis, Storage, and CTs
- Hydrogen Retrofit Project
    - Available Water
    - Available Transmission
    - Interim/Redundant Gas Supply



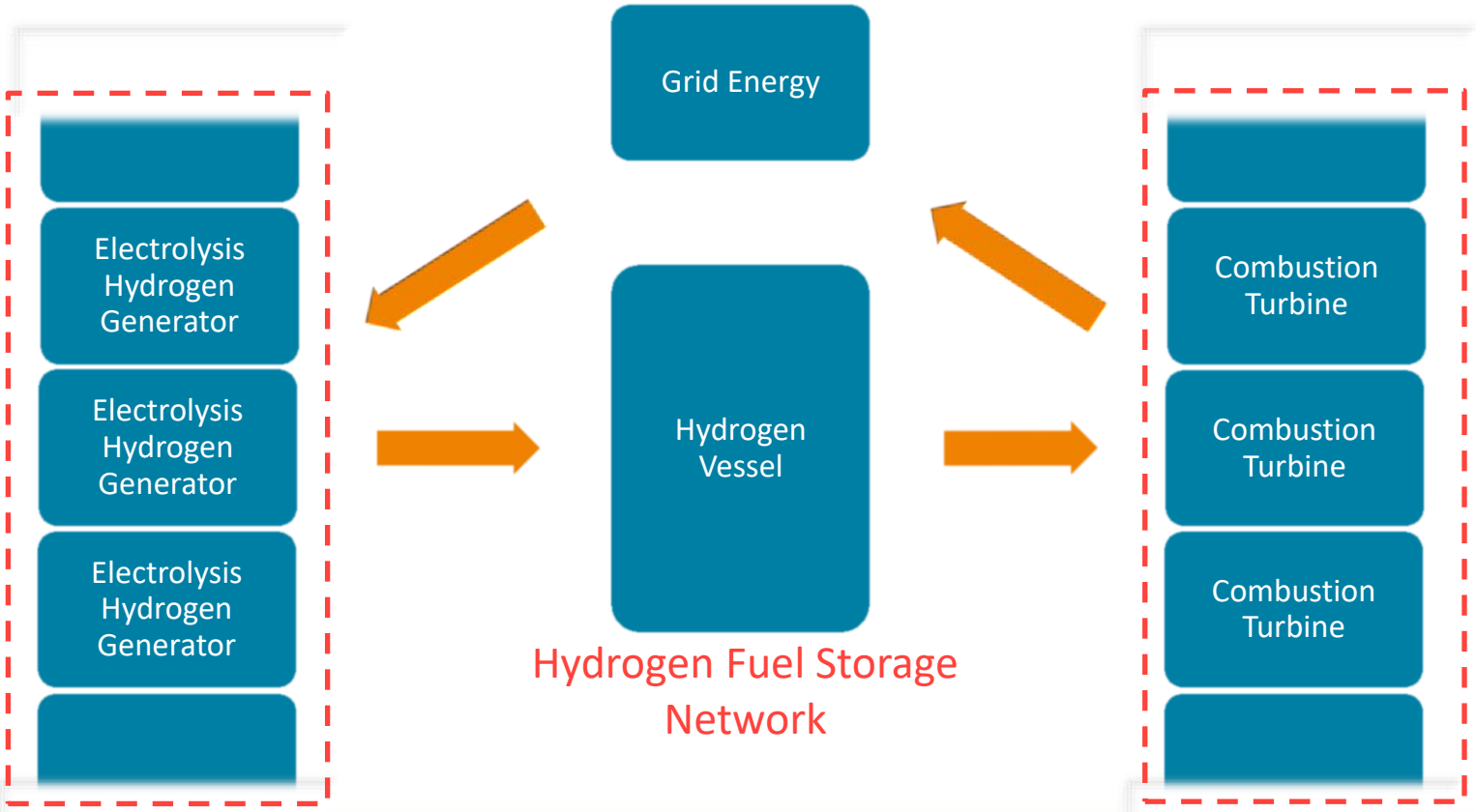
POWER TO HYDROGEN – SINGLE SITE



POWER TO HYDROGEN – SINGLE SITE

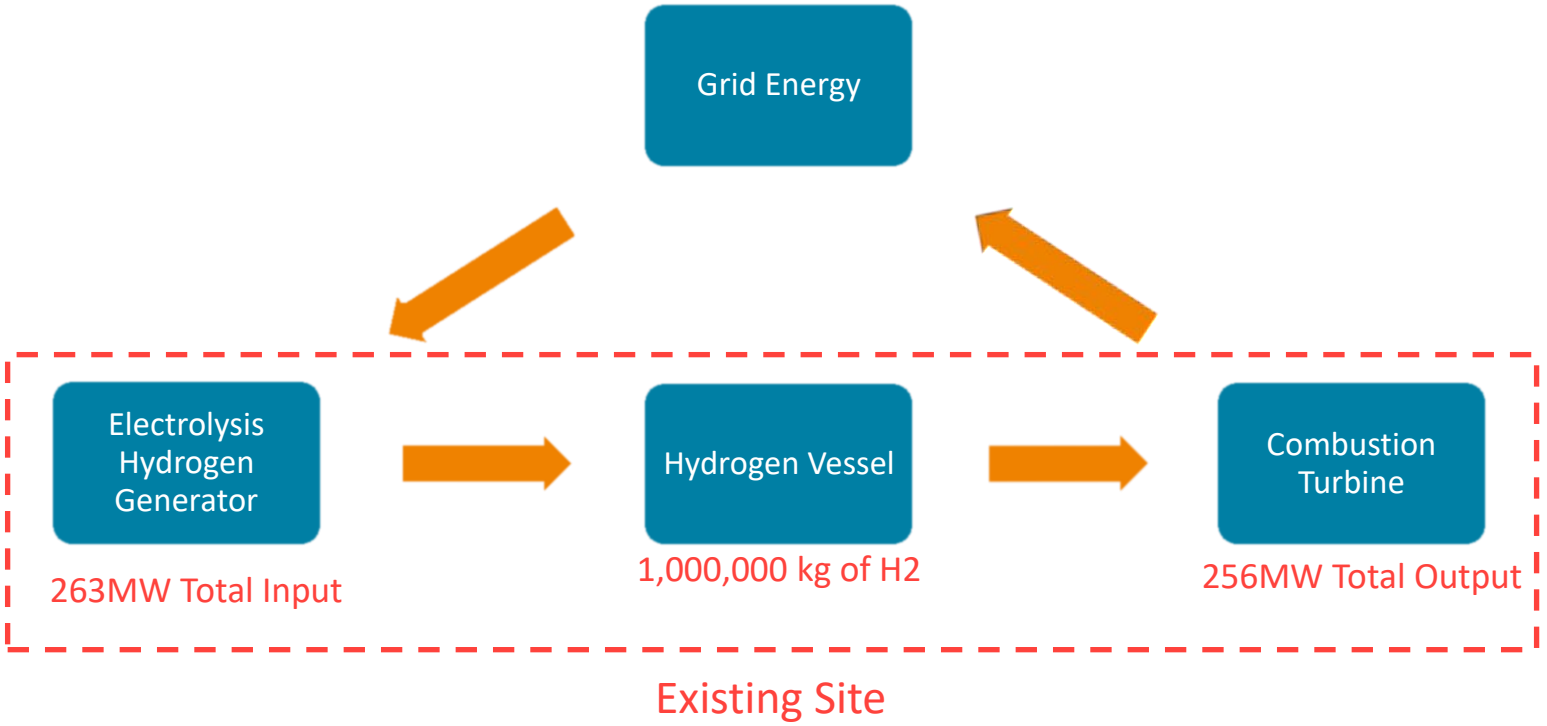


POWER TO HYDROGEN – DISTRIBUTED GENERATION

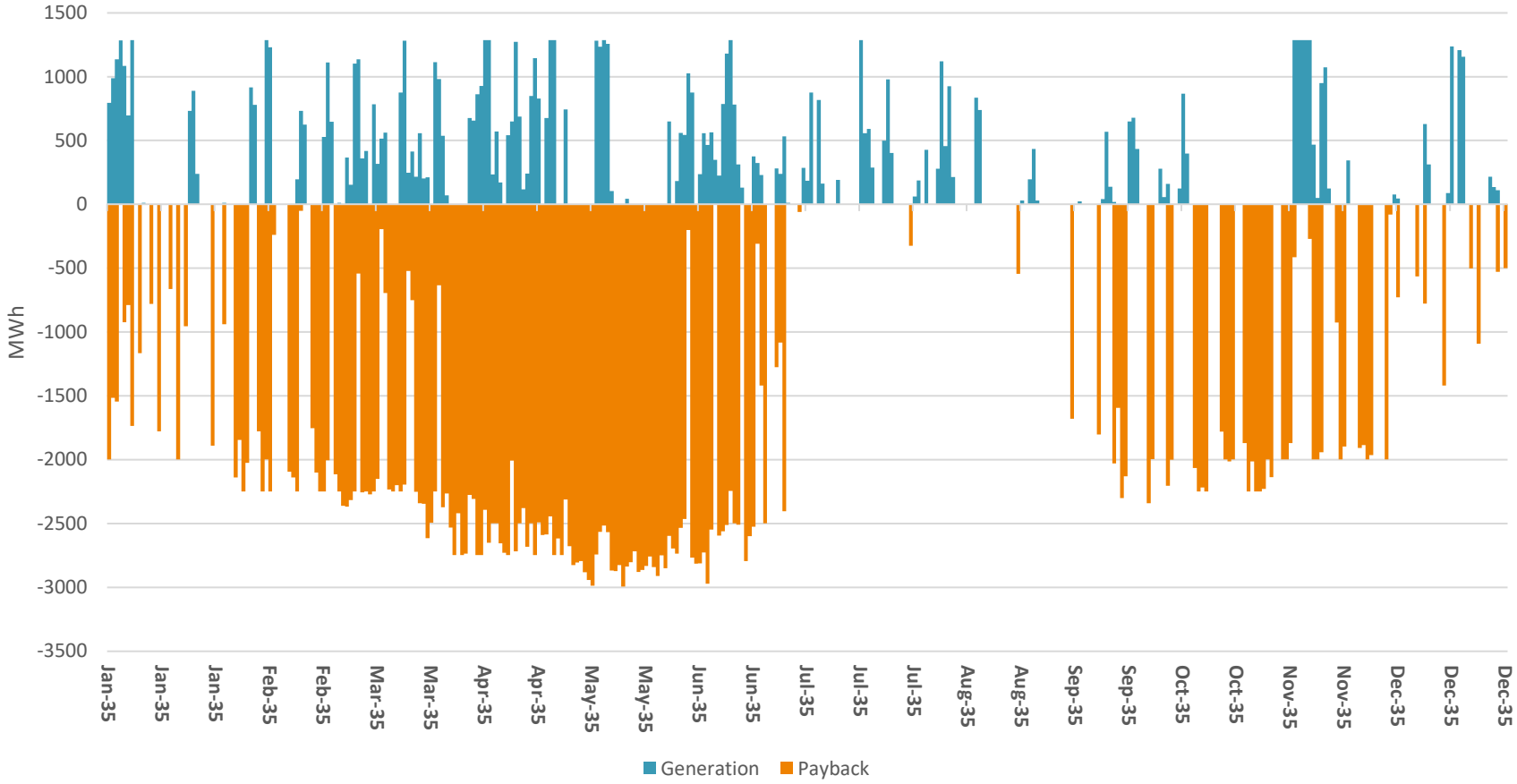


Talk to us.

POWER TO HYDROGEN – HYDROGEN RETROFIT

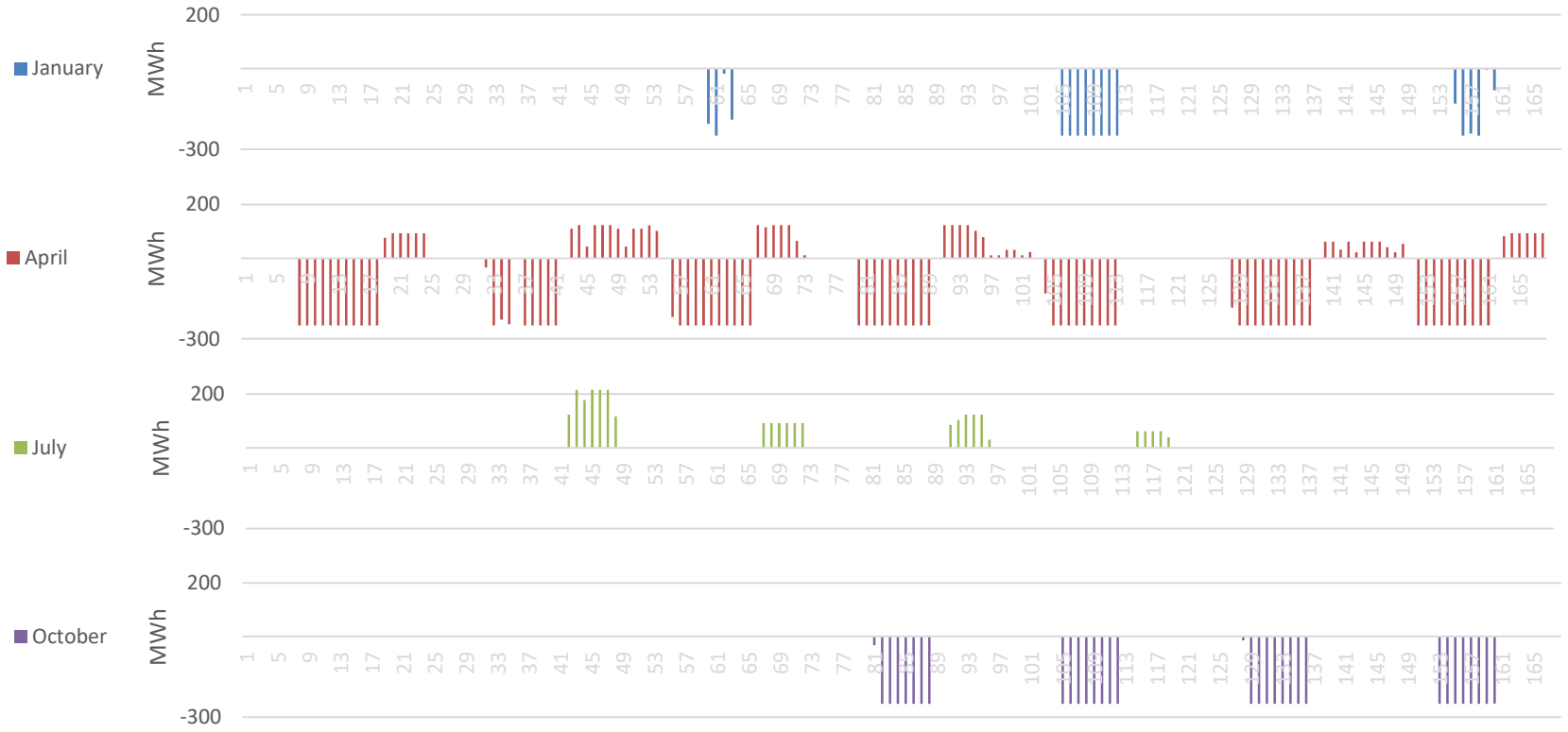


POWER TO HYDROGEN – HYDROGEN RETROFIT



Talk to us.

POWER TO HYDROGEN – HYDROGEN RETROFIT



Talk to us.

BATTERY STORAGE NEEDS (ONGOING)

2020 IRP, Figure 85. Timing & seasonality of reliability events by 2025

Share of Expected Unserved Energy by Month & Time of Day, Technology Neutral Scenario, 2025

Month	Hour of Day (MST)																							
	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Greatest risk of loss of load occurs after sundown				-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.4%	3.3%	5.8%	0.7%	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3%	1.5%	1.4%	17%	37%	14%	3.1%	0.3%	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3%	0.2%	5.5%	9.2%	0.6%	0.0%	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Approximate sunset (hours with typical solar capacity factors <5%)					-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-

2020 IRP, Figure 87. Timing and seasonality of reliability events, No New Combustion (Low Imports) scenario, 2040

Share of Expected Unserved Energy by Month & Time of Day, No New Combustion (Low Imports), 2040

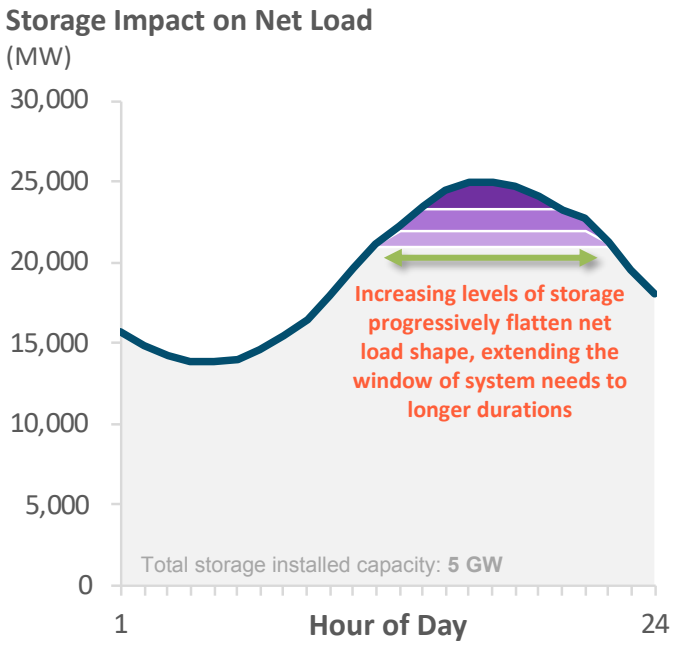
Month	Hour of Day (MST)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.4%	0.5%	0.8%	1.1%	1.6%	2.8%	5.6%	1.8%	0.0%	-	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%	0.5%
2	0.0%	0.1%	0.1%	0.1%	0.3%	0.6%	1.3%	0.3%	0.0%	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%	0.1%
3	-	-	-	0.0%	0.0%	0.2%	0.3%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	0.1%	0.1%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	0.3%	0.4%	0.5%	0.8%	1.4%	1.2%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.1%	0.2%
7	1.1%	1.9%	2.9%	4.5%	7.7%	7.8%	0.7%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	0.1%	0.1%	0.2%	0.3%	0.7%	1.1%
8	1.0%	1.5%	2.3%	3.3%	5.2%	7.5%	1.8%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.1%	0.2%	0.4%	0.7%	0.9%
9	0.1%	0.1%	0.2%	0.3%	0.6%	1.2%	0.5%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.1%
10	0.0%	0.0%	0.1%	0.2%	0.6%	1.5%	1.4%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
11	-	-	-	0.0%	0.0%	0.1%	0.3%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	0.2%	0.3%	0.4%	0.8%	1.6%	2.9%	5.4%	1.4%	-	-	-	-	-	-	-	-	-	-	0.0%	0.1%	0.1%	0.1%	0.2%	0.3%

PNM Talk to us. PNM.com

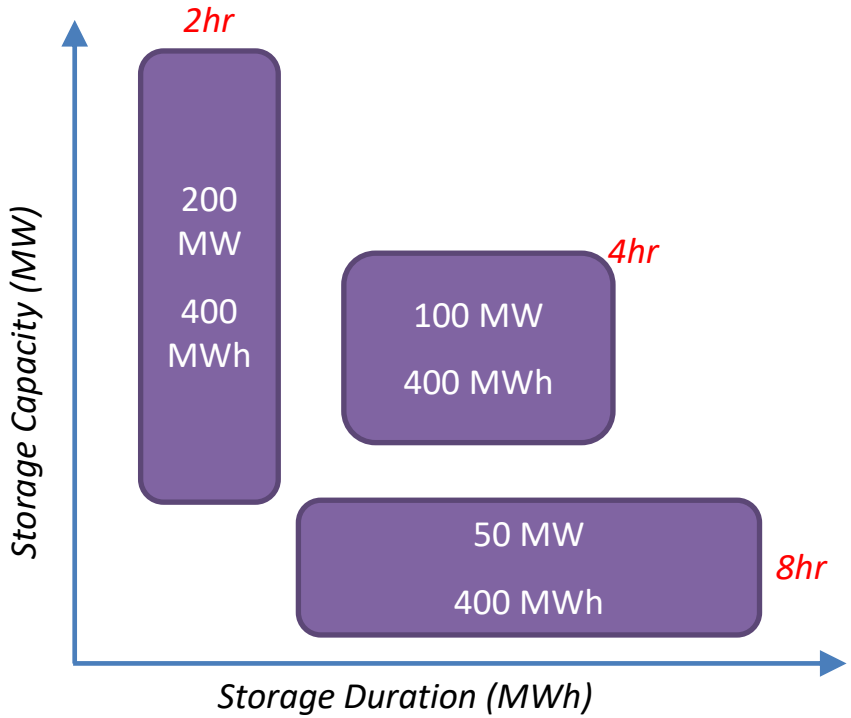
BATTERY STORAGE NEEDS (ONGOING)

Storage capacity contribution declining over time as net load shape flattens over time

Example from 6/27/2022 IRP Meeting



EnCompass to optimize storage requirements, however, additional analysis may be needed to determine if adjustments are needed to help meet/maintain reliability



Talk to us.

RECAP

PNM is continuing to improve modeling

- Maximizing Speed and Detail
- Updated Modeling of Energy Efficiency Bundles
- Adding Longer Duration Storage
- Adding Power to Hydrogen

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: August 3, 2022

Topic: Public Advisory Technical Session #5 Open Stakeholder Presentations or Review Topics (as requested)

Start Time: 9:00 AM

Location: Virtual

PNM will hold virtual meetings until circumstances warrant a change. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: August 17, 2022

Topic: Public Advisory Steering Meeting #4: Transmission

Start Time: 9:00 AM

Location: Virtual

PNM will hold virtual meetings until circumstances warrant a change. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by July 31, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Public Advisory Group Day

STEERING MEETING #4 **AUGUST 17, 2022**



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

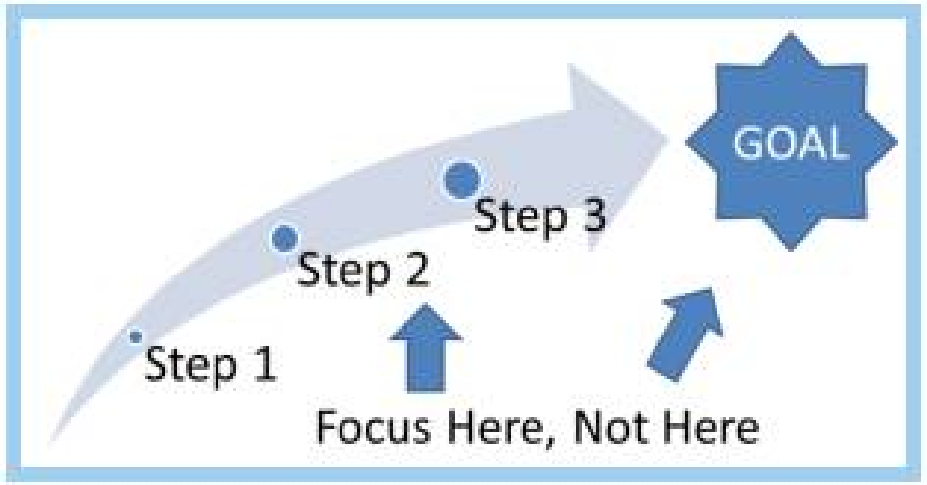
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

- Welcome and Introductions
- Presentation – Grid Strategies (Michael Goggin)
- Next steps and Near-Term Schedule

Potential methods to account for correlated generator outages

Michael Goggin

Grid Strategies LLC

August 17, 2022



Methods for accounting for correlated outages and derates of conventional generators

- Correlated conventional generator outages due to equipment failures and fuel supply interruptions have played a major role in recent reliability events.
- Effective Load Carrying Capability (ELCC) methods capture correlations in output patterns for renewable and storage resources. Conventional generators also exhibit correlated outages and derates, but those are not typically accounted for.
- Ignoring conventional generator correlated outages can bias resource selection, and mask reliability risk.
- Grid operators and others have developed methods for evaluating risks to resource adequacy and resilience from correlated conventional generator outages and derates.
- Some methods apply ELCC to conventional generators using historical patterns for generator outages.
- Other methods focus more on testing a large number of potential generation mixes under a range of plausible conditions.

Astrape "Accrediting RA Value to Thermal Gen"

		Winter Accreditation Impact	Winter Capacity Credit[1]	Summer Accreditation Impact	Summer Capacity Credit
Standard Accounting Practice	Forced Outage Rate	5.0%	95.0%	5.0%	95.0%
Proposed Additional Considerations	Outage Variability	2.7%	92.3%	4.6%	90.4%
	Outage Correlation	2.3%	90.0%		
	Weather Dependent Outages	10.0%	82.3%[2]	5.6%	84.7%
	Fuel Supply Outages[3]	6.2%	76.1%[4]		

Astrape found that accounting for correlations in conventional generator outages due to equipment failures and fuel supply interruptions significantly reduced their capacity value. In summer the capacity value was reduced from 95% to 85%, and in winter to 76%. This analysis was done for PJM South (Dominion's footprint in Virginia and parts of West Virginia and North Carolina), but could be done for other regions.

https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf

Ideas explored as part of MISO moving to Seasonal RA

- As it was developing a seasonal resource adequacy approach, MISO explored ways to account for correlated outages in both testing system LOLE and accrediting capacity value to resources.
- In SERVM modeling of system LOLE, “an adjustment will be applied within the model to account for increased forced outages during extreme weather events. When the temperature drops below a certain threshold in the model, the outage rates for thermal resources will be increased to represent the correlation between extreme temperatures and forced outages.”
- Capacity value accreditation would be based on historical performance during tight system conditions, and class averages would be applied to new resources.

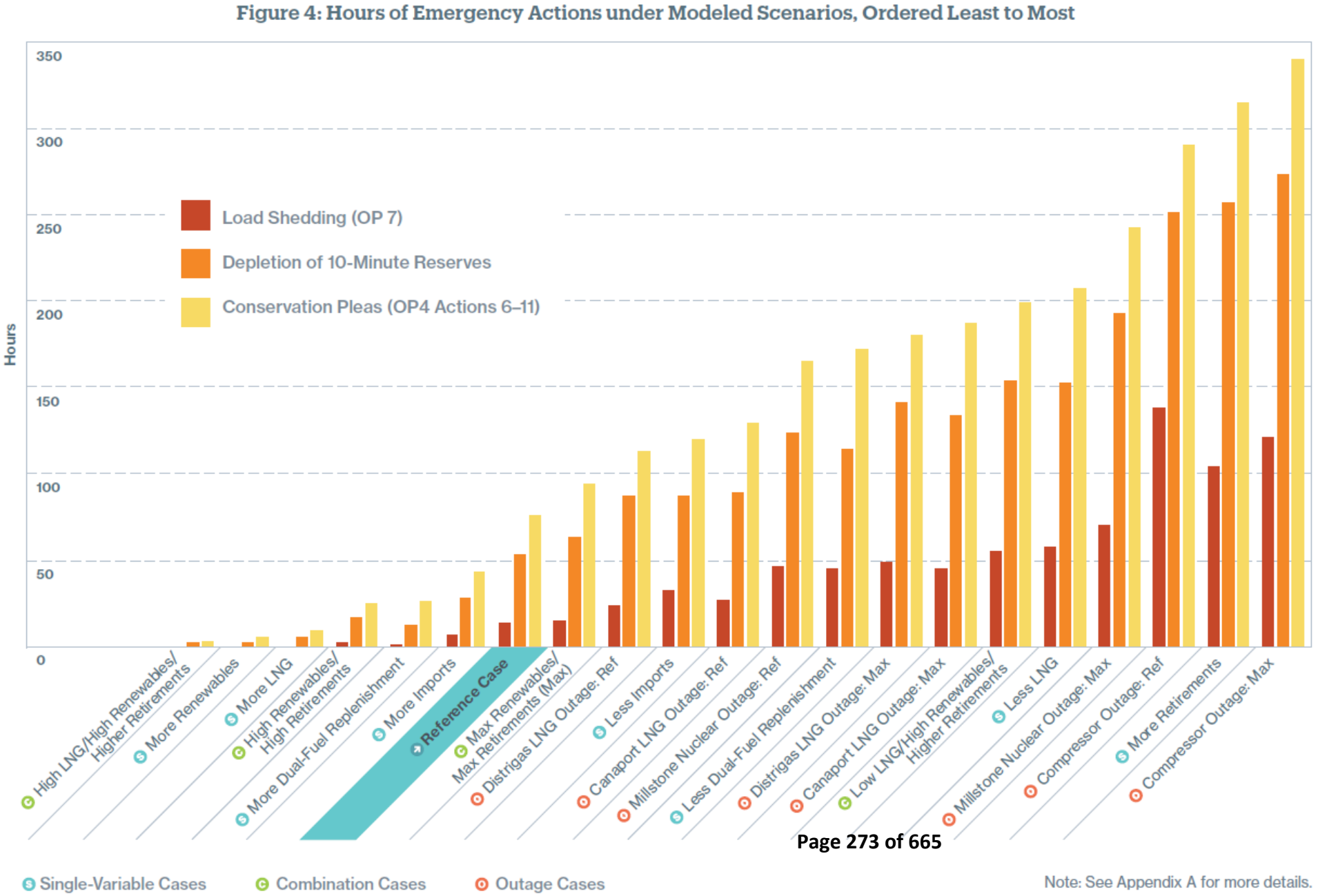
https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20Seasonal%20RA%20Conceptual%20Design585538.pdf

“PJM’s Evolving Resource Mix and System Reliability”

- First PJM conducted a risk analysis in which hundreds of potential generation mix “portfolios were assessed for their ability to provide the generator reliability attributes … under four operational states: normal peak conditions, light load, extremely hot weather and extremely cold weather.”
- *The resilience of the portfolios identified as desirable by the risk analysis was tested by subjecting the desirable portfolios to a polar vortex event. Such an event may trigger higher-than-average unavailability rates for fuel types such as natural gas, coal and solar. To determine these potential higher-than-average unavailability rates, generator performance data from high load days during Winter 2014/2015 and Winter 2015/2016 were analyzed by fuel type. The maximum unavailability rates during those days were applied to the portfolios in the desirable region. Reliability indices and composite reliability indices were recalculated.*
- *Only 34 of the 98 portfolios which were classified as desirable were resilient when subjected to a polar vortex event. This sensitivity specifically captured the increased risk of natural gas delivery under extremely cold and high load conditions. The polar vortex sensitivity highlights the importance of resilience, which is not captured by the generator reliability attributes that were considered in this study.*

https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

ISO-NE "Operational Fuel-Security Analysis"



ISO-NE tested its ability to meet winter demand under 23 scenarios that varied the generation mix, generator outages, and gas supply outages.

https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

NERC 2017 Special Reliability Assessment

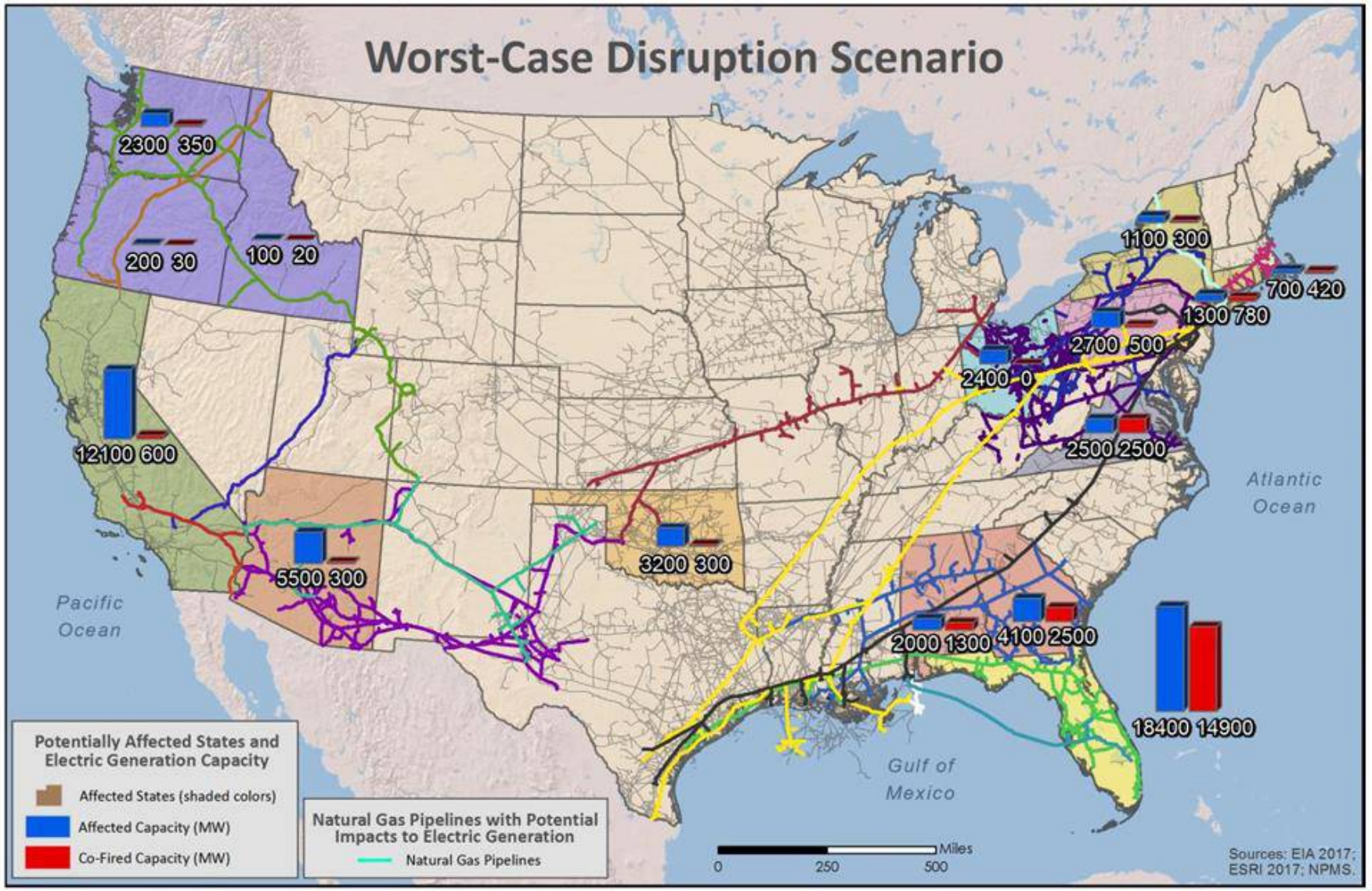


Figure E.2: Summary of NGfast Simulation Results for the Worst-Case Scenario

An Argonne National Laboratory tool (NGfast) was used to model the amount of gas generating capacity that could be taken offline by potential disruptions to the interstate gas pipeline system.

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

QUESTIONS/COMMENTS

WE WOULD LIKE TO HEAR FROM YOU

Any comments or questions regarding any of the topics PNM has previously presented?

Any feedback regarding any of drivers/assumptions that will be used in the 2023 IRP?

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: August 31, 2022

Topic: Public Advisory Steering Meeting #5: Emerging/Evolving Grid Solutions

Start Time: 9:00 AM

Location: Virtual

PNM will hold virtual meetings until circumstances warrant a change. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: September 15, 2022

Topic: Public Advisory Steering Meeting #6: Transmission

Start Time: 9:00 AM

Location: Virtual

PNM will hold virtual meetings until circumstances warrant a change. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by August 29, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Transmission (1 of 2)

STEERING MEETING #5

SEPTEMBER 13, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

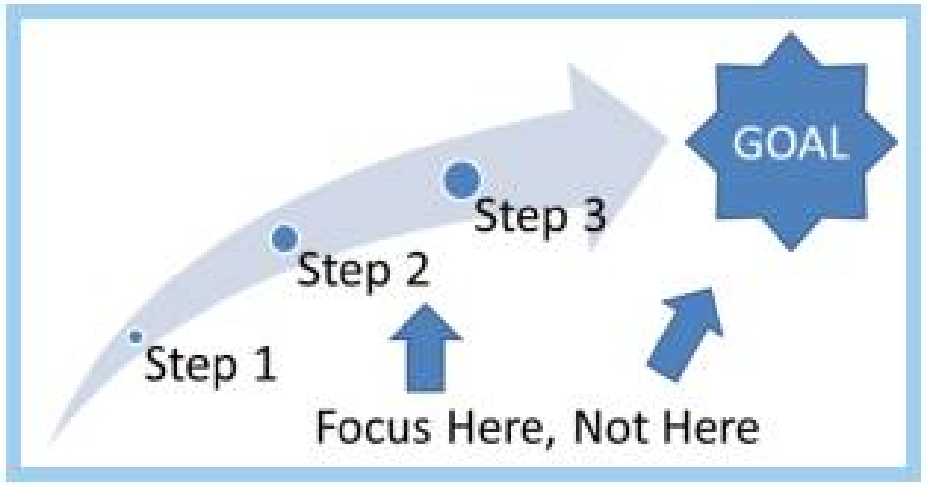
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

AGENDA

PNM Transmission Engineering

- Transmission System Overview
- Role of Transmission in Energy Transition
- PNM's Transmission System and Capability
- Transmission - Regulatory Construct
- The Transmission/Generation Challenge
- Transmission Strategy Going Forward
- Transmission in IRP

E3

- Transmission in Utility Integrated Resource Planning

PNM Integrated Resource Planning and transmission teams

- PNM Transmission Modeling for IRP – 2020 & 2023
- Nodal Transmission Modeling

PNM
Transmission Engineering

Laurie Williams - Director, Transmission and Substation Engineering

Tom Duane - Manager, Transmission Planning

INTRODUCTIONS

Laurie Williams
Director, Transmission and Substation Engineering

- Ms. Williams directed the Transmission and Substation Engineering teams for the last 1.5 years. She has over 30 years of experience in utility industry including Transmission Planning, Integrated Resource Planning, and NERC Compliance.
- She provides direction for PNM's Transmission Planning and Contracts, Protection – Controls –Communications Engineering, Transmission Line and Substation Design and Engineering, and Strategic Asset Management including Cyber and Physical Security for the transmission system.

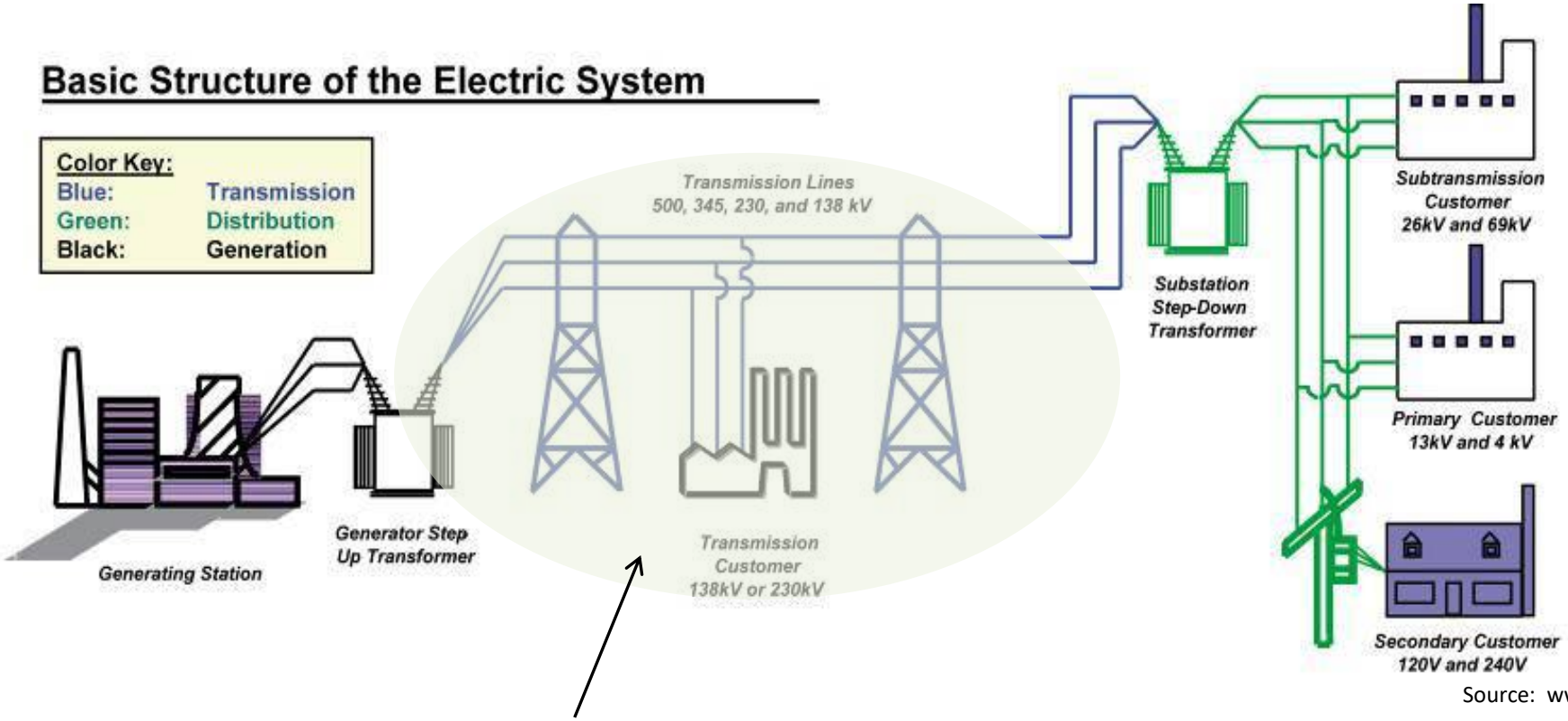
Tom Duane
Manager, Transmission Planning

- Mr. Duane has managed the PNM transmission planning department over the last ten-years. He has supported transmission system analysis and expansion for over 25 years including representation of PNM in regional planning and stakeholder forums.
- Mr. Duane has significant experience in the electric industry that includes providing technical support and guidelines for system operations as well as generation development activities through production cost analysis, market analysis and corporate modeling input.

Transmission Overview and the Role of Transmission in the Energy Transition

Laurie Williams

COMPONENTS OF THE GRID



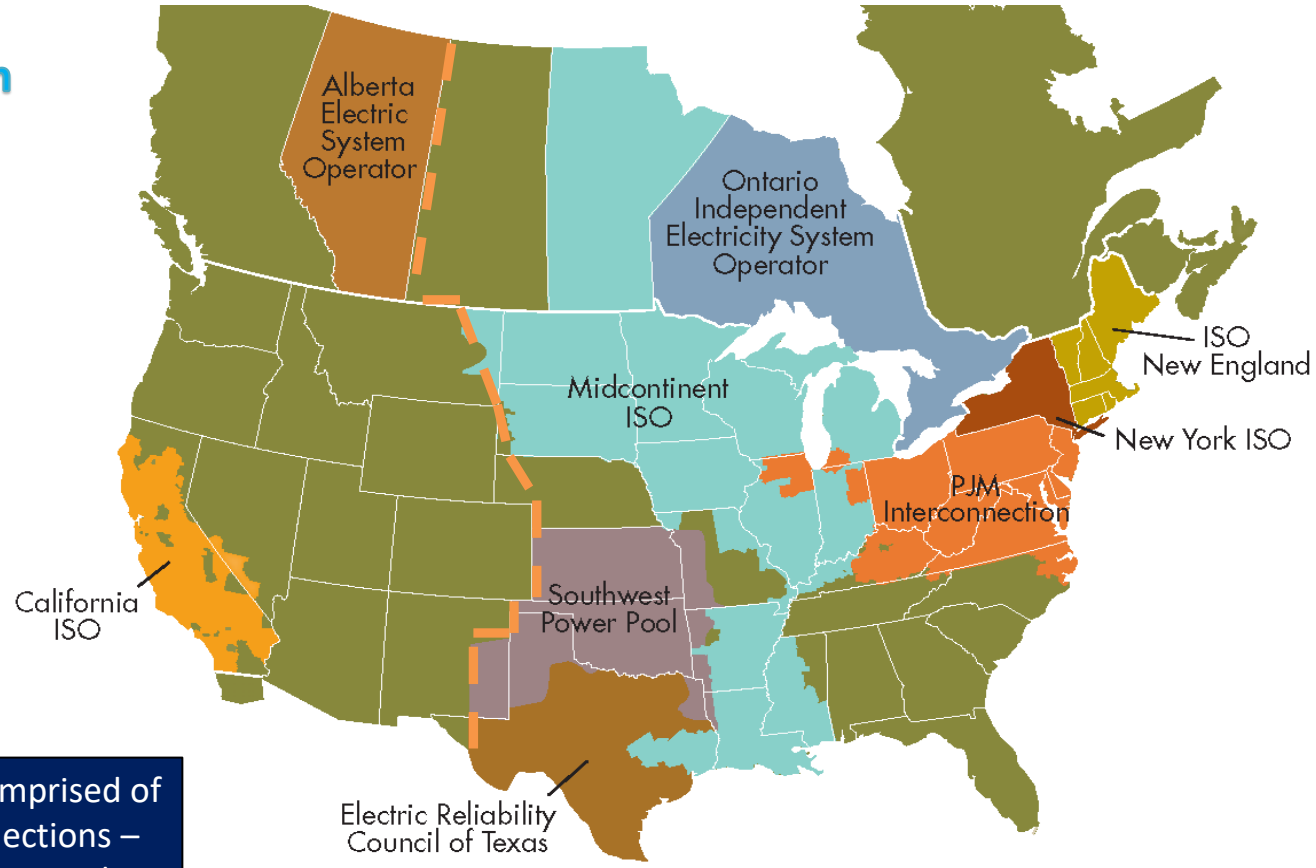
Source: www.nerc.com

PNM Transmission Voltage Levels include 115kV, 230kV, 345kV and 500kV

CURRENT US GRID – INTERCONNECTIONS AND REGIONAL TRANSMISSION OPERATORS

Western Interconnection

Home to roughly 250,000 MW of generating capacity



Eastern Interconnection

home to roughly 700,000 MW of generating capacity

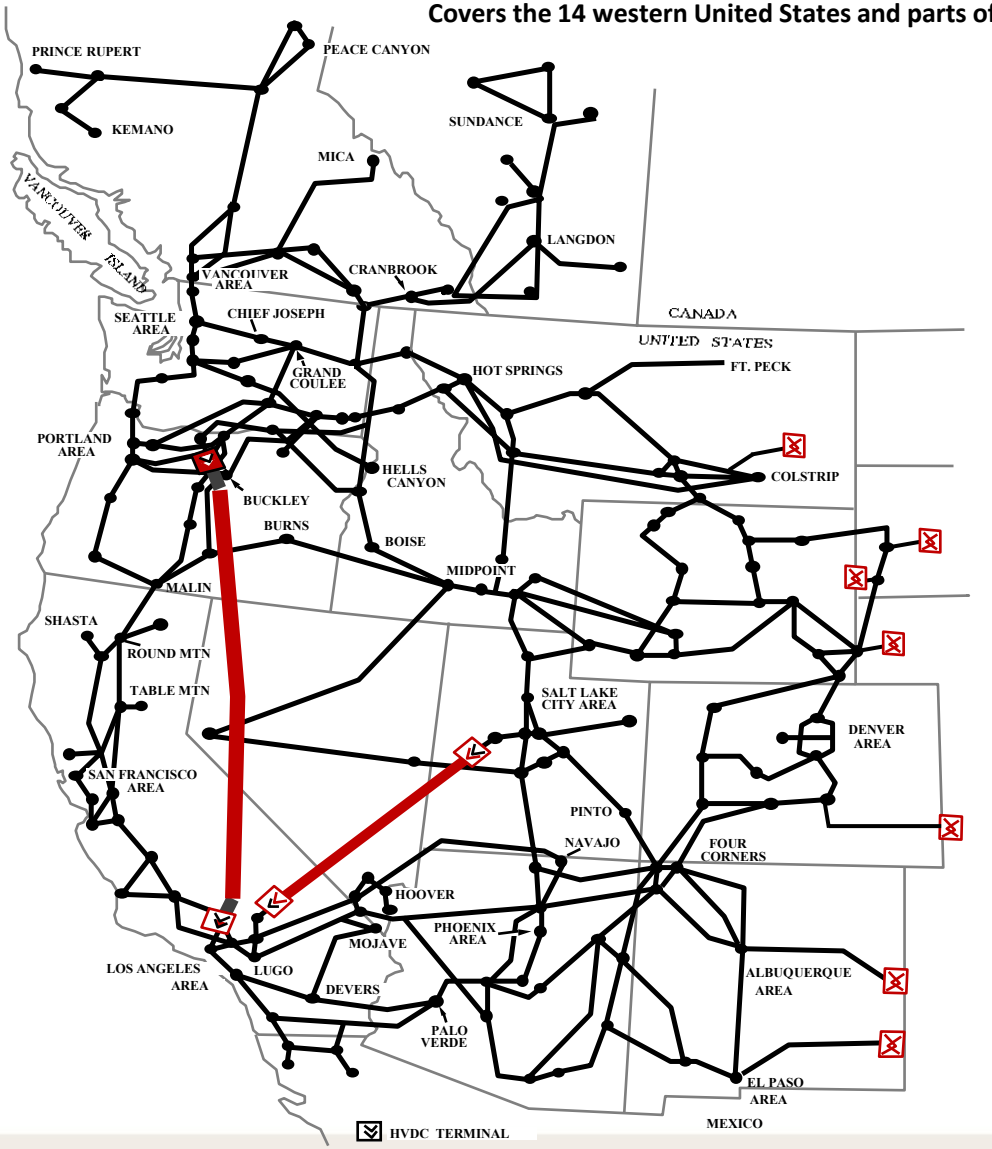
US Transmission Grid – Comprised of 3 Synchronous Interconnections – largely independent of one another

ERCOT Interconnection

Much of the system is organized "RTOs"

THE WESTERN INTERCONNECTION

Covers the 14 western United States and parts of Canada and Mexico



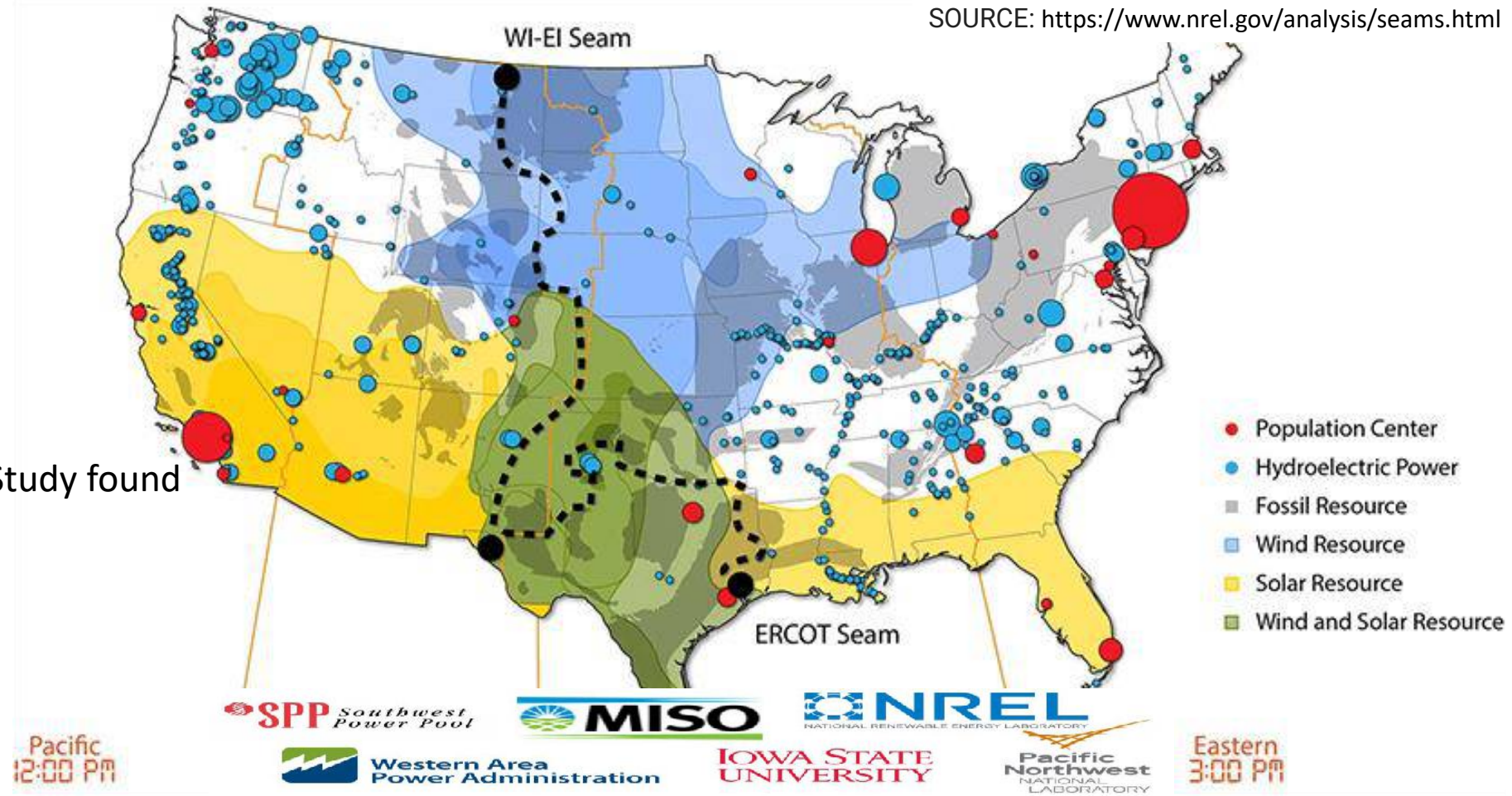
Key Characteristics:

- 1.6 million square miles, over 110k miles of transmission, population of approx. 74 million, ~165 GW peak
- Many Balancing areas (38) and transmission providers (55)
- **Only California in ISO/RTO**
- Historically Bilateral transactions dominate – now resource constrained and EIM becoming more prominent
- Historically economy of scale drove remote jointly-owned base load plants and long transmission lines to connect to load centers
- 2 High Voltage DC lines (serving So. California)
- **7 back-to-back High Voltage DC ties to eastern interconnection allow only 1,320 MW to move between the Eastern and Western grids**

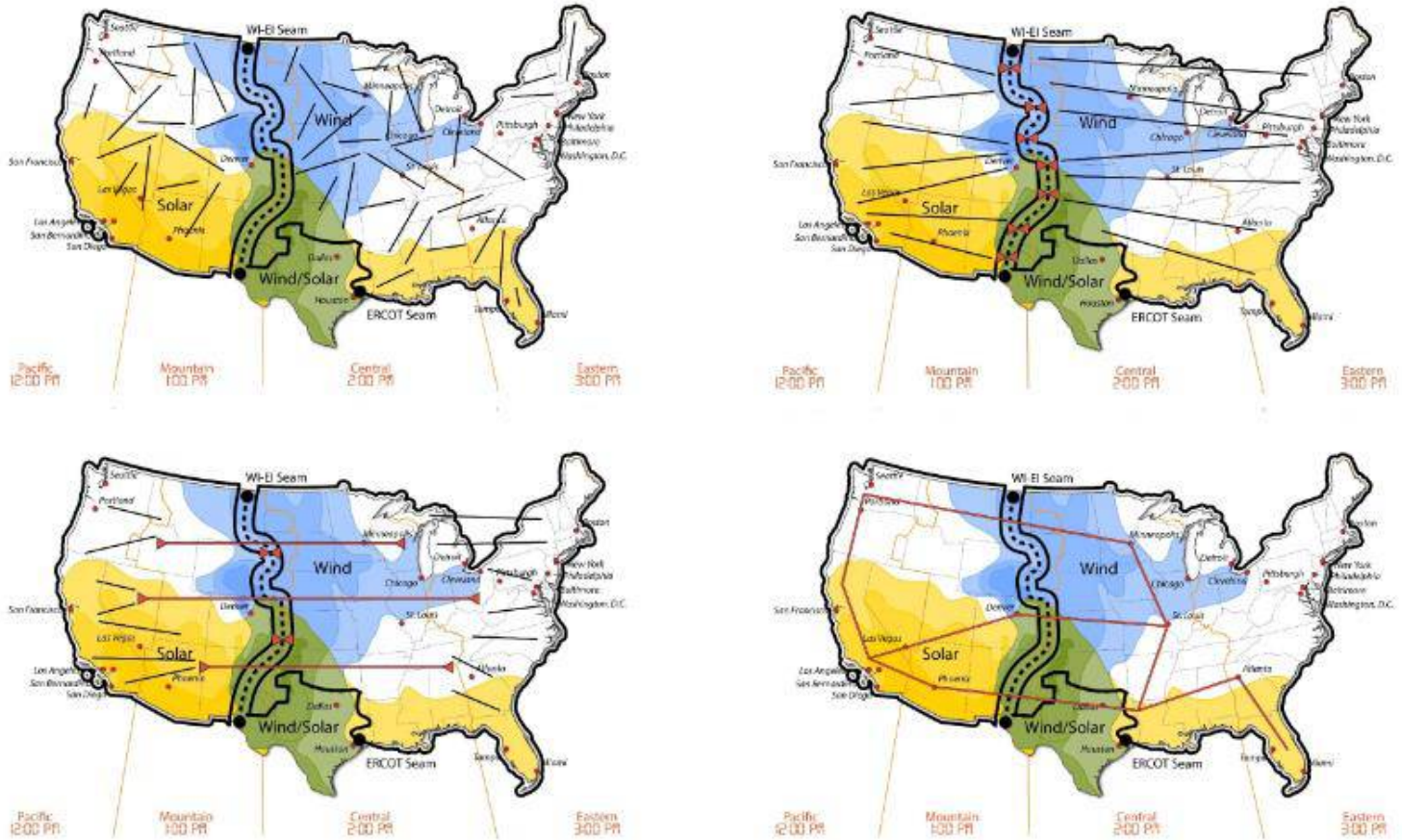
NREL SEAMS STUDY - COMPREHENSIVE ECONOMIC AND RESOURCE ADEQUACY ANALYSIS

SOURCE: https://www.nrel.gov/analysis/seams.html

Study found



NREL SEAMS STUDY METHODOLOGY



Transmission designs in the capacity expansion work. Top left: Design 1. Top right: Design 2a. Bottom left: Design 2b. Bottom right: Design 3.

Modeled transmission and generation co-optimized for four different transmission designs

PNM Talk to us. PNM.com

STUDY METHODOLOGY

Scenario	Key Assumption Differences
Base Case	AEO 2017 gas price, existing state RPS laws
Low Gas Price	AEO 2017 High Gas Resource (gas prices regionally and temporally varying around $4/mmbtu)
High Gas Price	AEO 2017 Low Gas Resources (gas prices varying around $6/mmbtu)
High AC Trx Cost (1.5x)	50% higher than base transmission cost. Base transmission cost from [16]
High AC Trx Cost (2x)	Double the base transmission cost
No Retirements	Model does not retire any generating units beyond announced retirements
Low-Cost Renewables	ATB 2017 Low Cost projections for wind and solar
High VG	Least-cost generation mix when using a carbon cost from $3/tonne in 2024 to $45/tonne in 2038**

Description of the Scenarios*
*Acronyms used here include Energy Information Administration (EIA) Annual Energy Outlook (AEO); Renewable Portfolio Standard (RPS); Annual Technology Baseline (ATB) (atb.nrel.gov); Variable Generation (VG);
Transmission (Tx)
**: The study Technical Review Committee recommended this approach (consistent with cost estimates in [17]) as a proxy for potential growth in wind and solar in light of uncertainty in traditional deployment forecasts

- The four conceptual transmission designs were studied under eight different grid environments
- A total of 32 total capacity expansion model runs were made
- Scenarios vary in terms of technology cost, fuel price, and policy assumptions
- Refer to preprint article for numbered references

COST/BENEFIT RESULTS

Summary of Benefit/Cost Results from CGT-Plan Model

Base Scenario

Capacity or Cost Item	D1	ΔD2a	ΔD2b	ΔD3
Transmission Investment Cost, $B	40.03	2.57	6.76	8.19
Generation Investment Cost, $B	555.23	3.6	10.44	4.17
Operational cost, $B	2376.50	-8.79	-21.70	-15.30
35-yr Net Cost change, $B	-	-2.62	-4.5	-2.94
35-yr B/C ratio	-	2.02	1.66	1.36

High VG Scenario

Capacity or Cost Item	D1	ΔD2a	ΔD2b	ΔD3
Transmission Investment Cost, $B	71.69	16.79	15.6	28.86
Generation Investment Cost, $B	741.38	6.83	8.02	7.95
Operational Cost, $B	2563.3	-41.97	-52.45	-59.85
35-year Net Cost change , $B	NA	-18.35	-28.83	-23.04
35-year B/C Ratio	NA	2.09	2.89	1.80

Note: D1 results are shown as absolute costs; D2a, D2b, and D3 results are shown relative to D1.
In the High VG case, carbon costs are included in the optimization but not the net costs or B/C ratio

KEY NREL FINDINGS

- The power system can balance generation and load
- Additional transmission enabled lower total installed capacities (especially in the High VG scenario)
- There are substantial positive benefit-cost ratios for increasing the transfer capability between the interconnections
- Cross-seam transmission has a substantial impact on the location of wind and solar generation additions
- Wind shifts to the Eastern Interconnection and solar to the Western Interconnection
- Additional benefits and costs may exist (e.g., frequency response and resilience to extreme events)
- **Findings repeated in NREL's North American Renewable Integration Study** https://www.nrel.gov/analysis/naris.html
    - Interregional transmission expansion achieves up to $180 billion in net benefits – "Transmission plays an important role in minimizing costs."

PRINCETON'S "NET-ZERO AMERICA" STUDY

- Lays out five pathways by which the United States could decarbonize the entire economy in the next 30 years
- According to the research, the United States will need to expand its electricity transmission systems by 60% by 2030 and may need to triple it by 2050

> *"The current power grid took 150 years to build. Now, to get to net-zero emissions by 2050, we have to build that amount of transmission again in the next 15 years and then build that much more again in the 15 years after that. It's a huge amount of change."*
>
> -Jesse Jenkins, Co-Principal Investigator, Senior Research Scientist, Andlinger Center for Energy and the Environment, Princeton University

Source: https://acee.princeton.edu/acee-news/net-zero-america-report-release/

THE BOTTOM LINE

Transmission is key to achieving the energy transition efficiently across the US

****

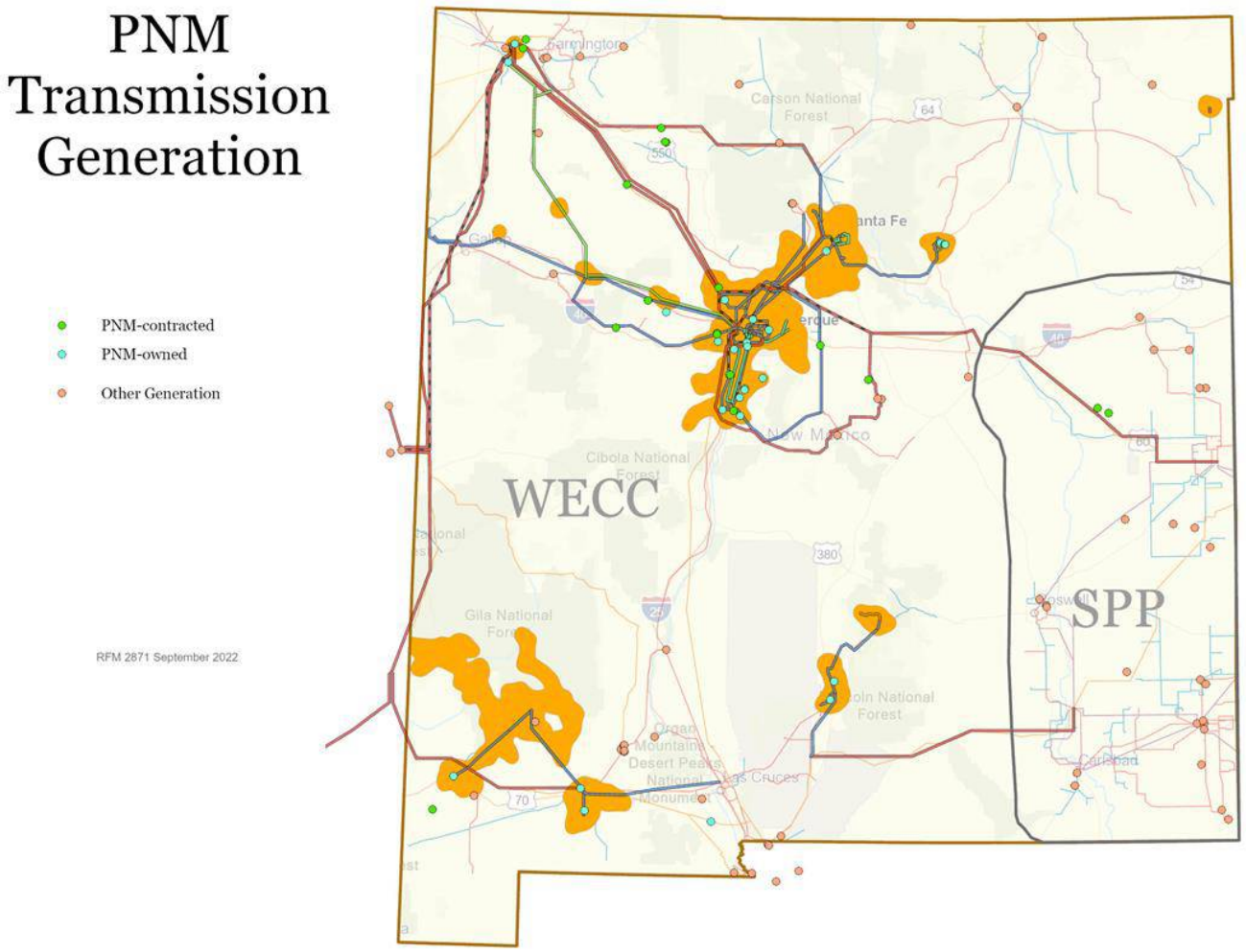
Broader use of Distribution will also be critical to success



PNM Transmission System Overview

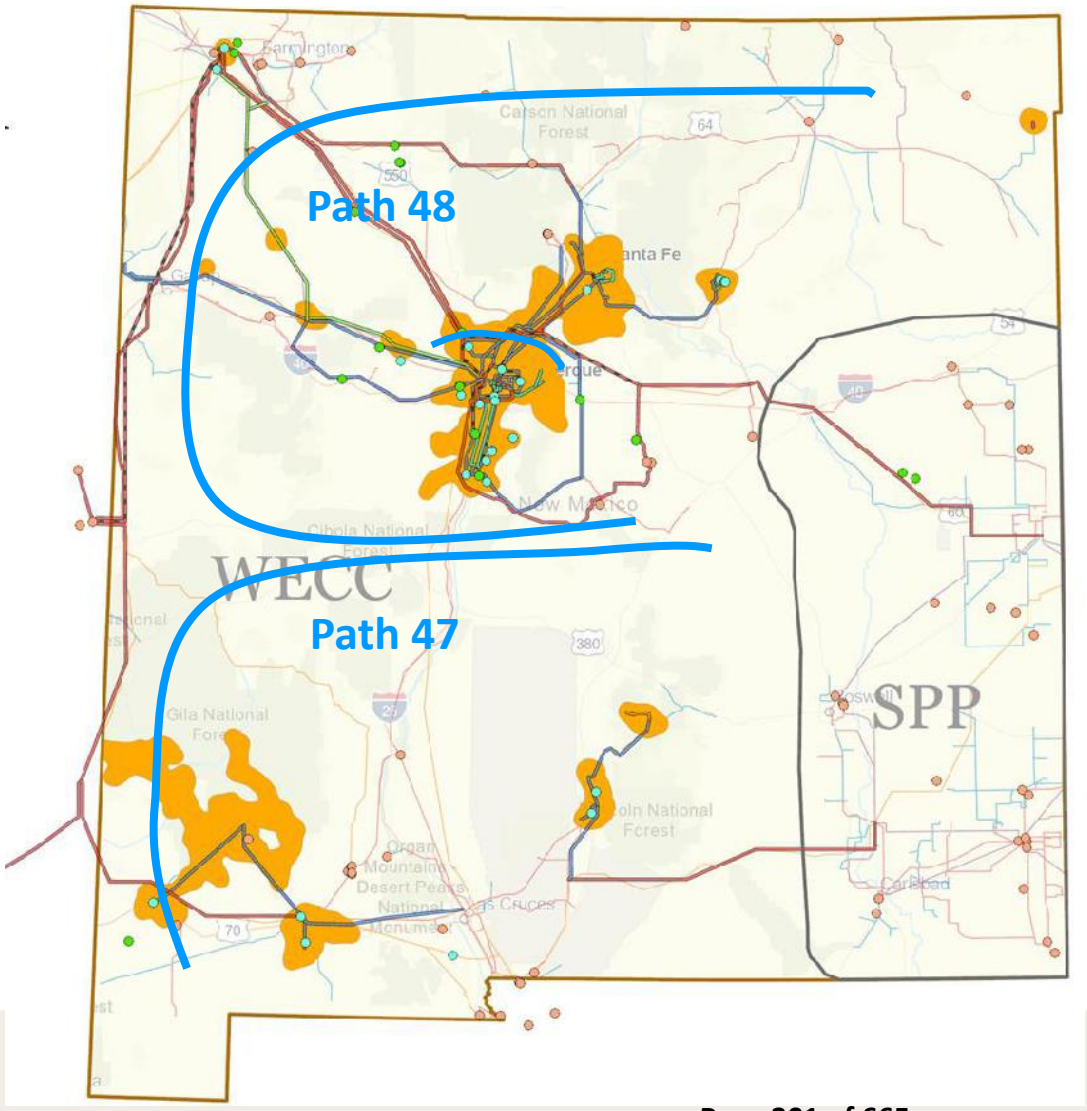
Tom Duane

NEW MEXICO SYSTEM OVERVIEW

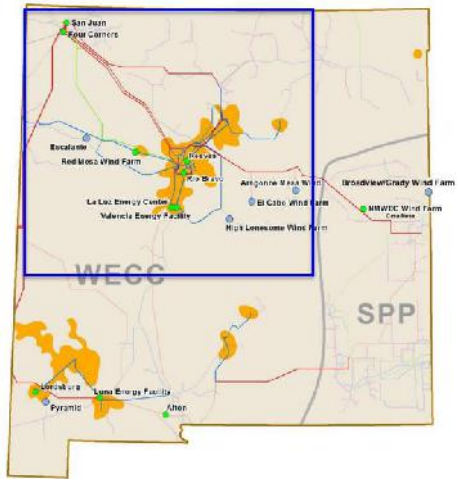


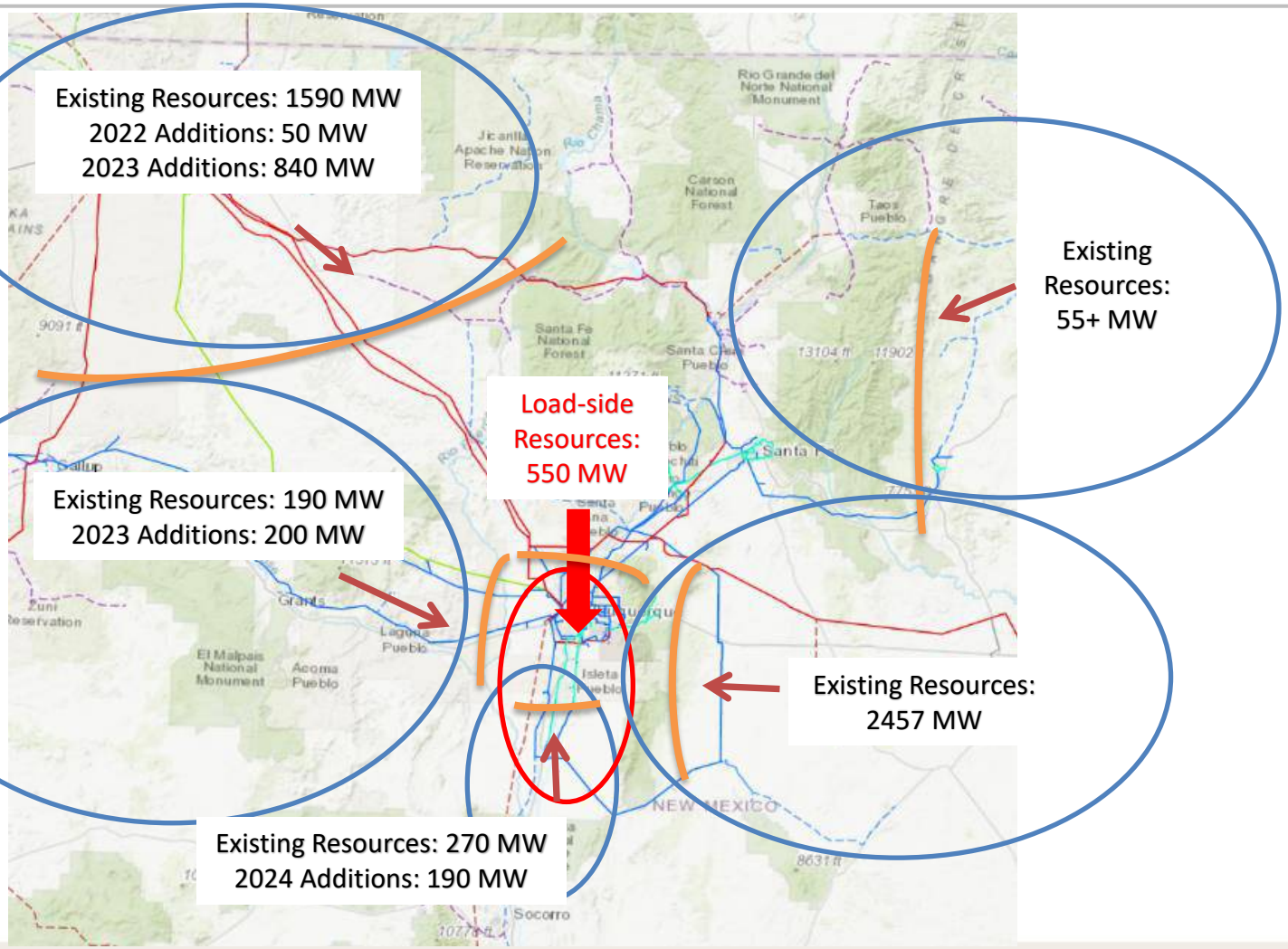
- Lines shown in red are the primary backbone transmission lines in NM
- Lower voltage lines provide a portion of the transmission capability to deliver resources and distribute power to outlying smaller load areas distant from Albuquerque and El Paso

TRANSMISSION LIMITATIONS: HISTORICAL CONSTRAINTS FOR GENERATION DELIVERY



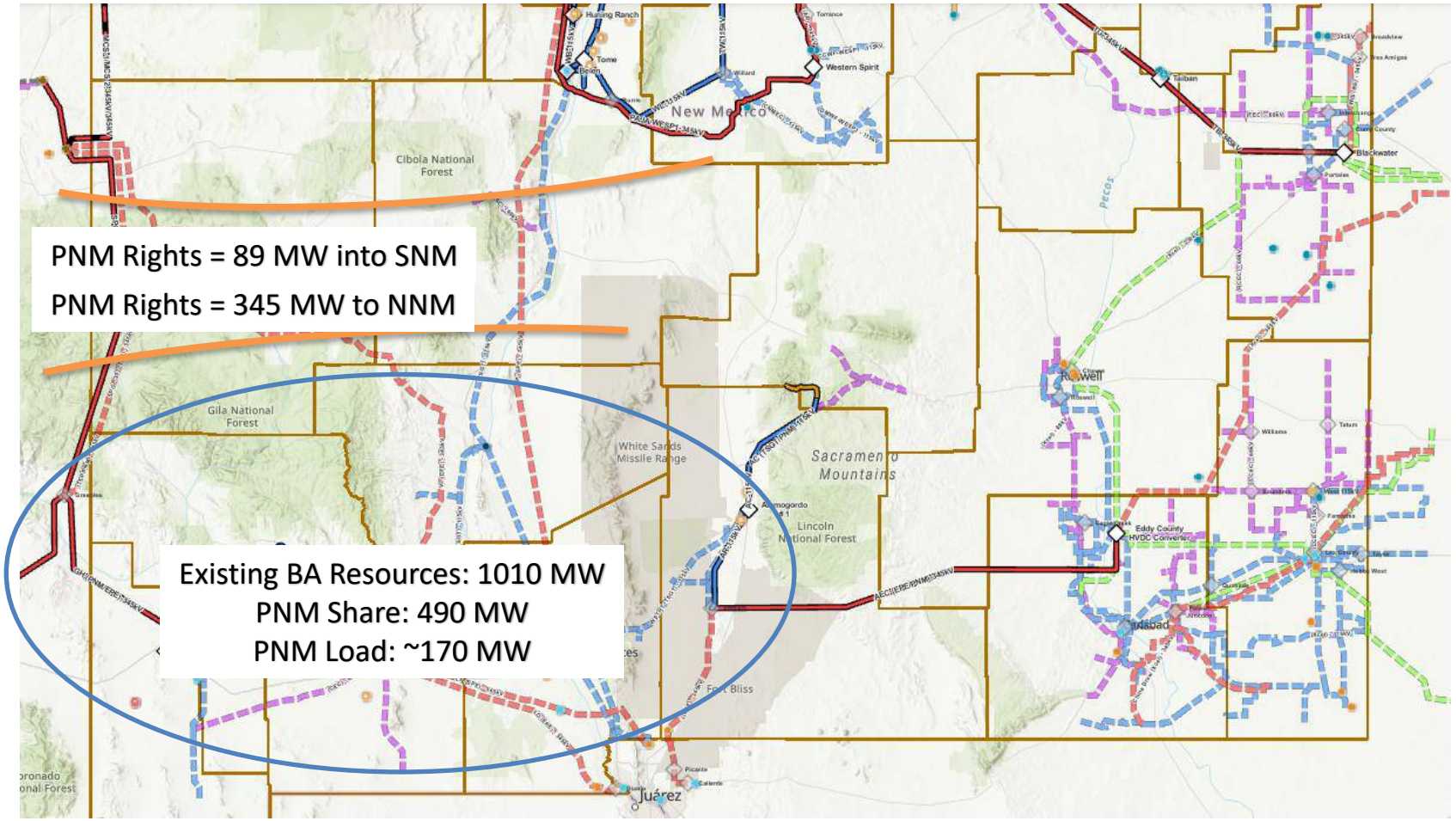
NORTHERN NM LIMITATIONS FOR GENERATION DELIVERY





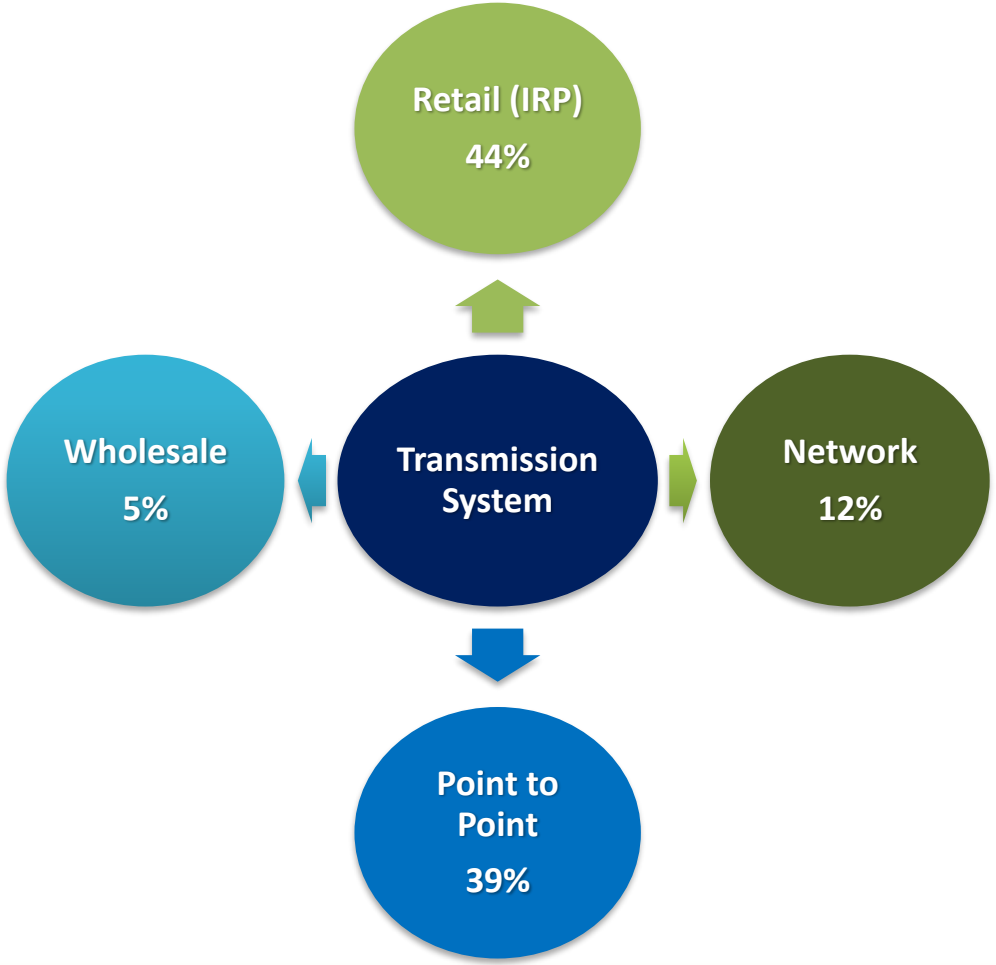
Talk to us.

SOUTHERN NM LIMITATIONS FOR GENERATION DELIVERY



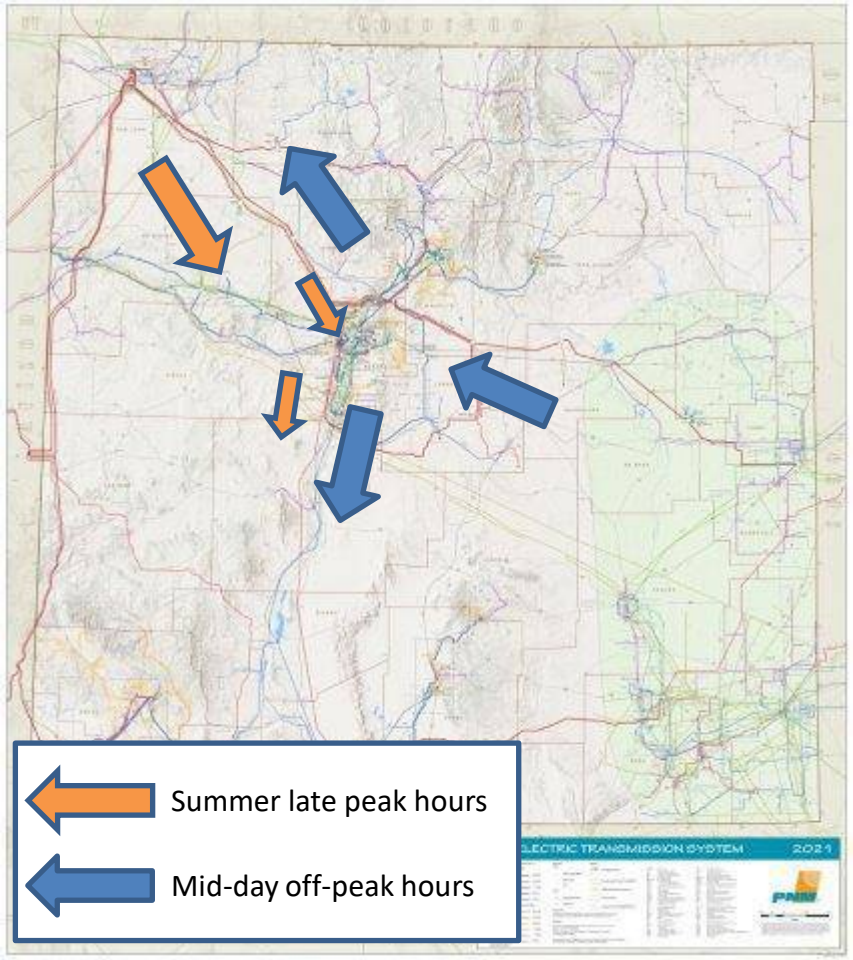
PNM TRANSMISSION SYSTEM USAGE

- Transmission grid serves all customers alike whether wholesale (utility-scale power delivery) or retail (services retail electric load customers)
- PNM plans and constructs its system to meet *all* forecasted customer needs, not just those covered by IRP
- Point-Point transmission service expected to exceed PNM retail usage starting in 2022



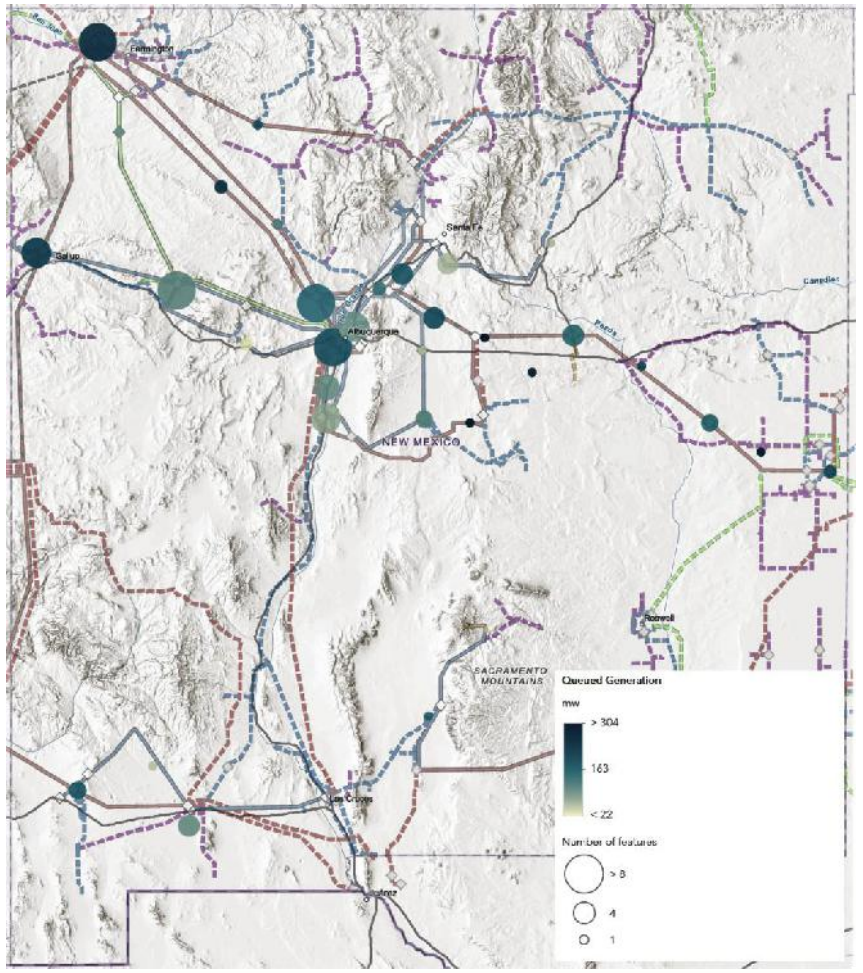
WHAT'S GOING ON TODAY?

- **Flows on major transmission change direction frequently**
  - Major lines loading in historical north to south direction with low wind conditions and late summer peak hours
  - Daytime hours during other months and high wind conditions flows are occurring at high levels in a south to north direction
- **North and South interdependence**
- **Fully subscribed in almost every location**
- **Southern NM Flows**
  - Flows can be in or out of southern New Mexico also depending on renewables and market price and season
  - Historical import levels are seen infrequently due in large part to gas generation in southern New Mexico, but historical transfer capability obligations remain
- **Generation resources are much smaller, more geographically diverse, and greater in numbers**
  - Transmission additions are much less efficient in this paradigm



INTERCONNECTION REQUESTS: GEOGRAPHIC DIVERSITY

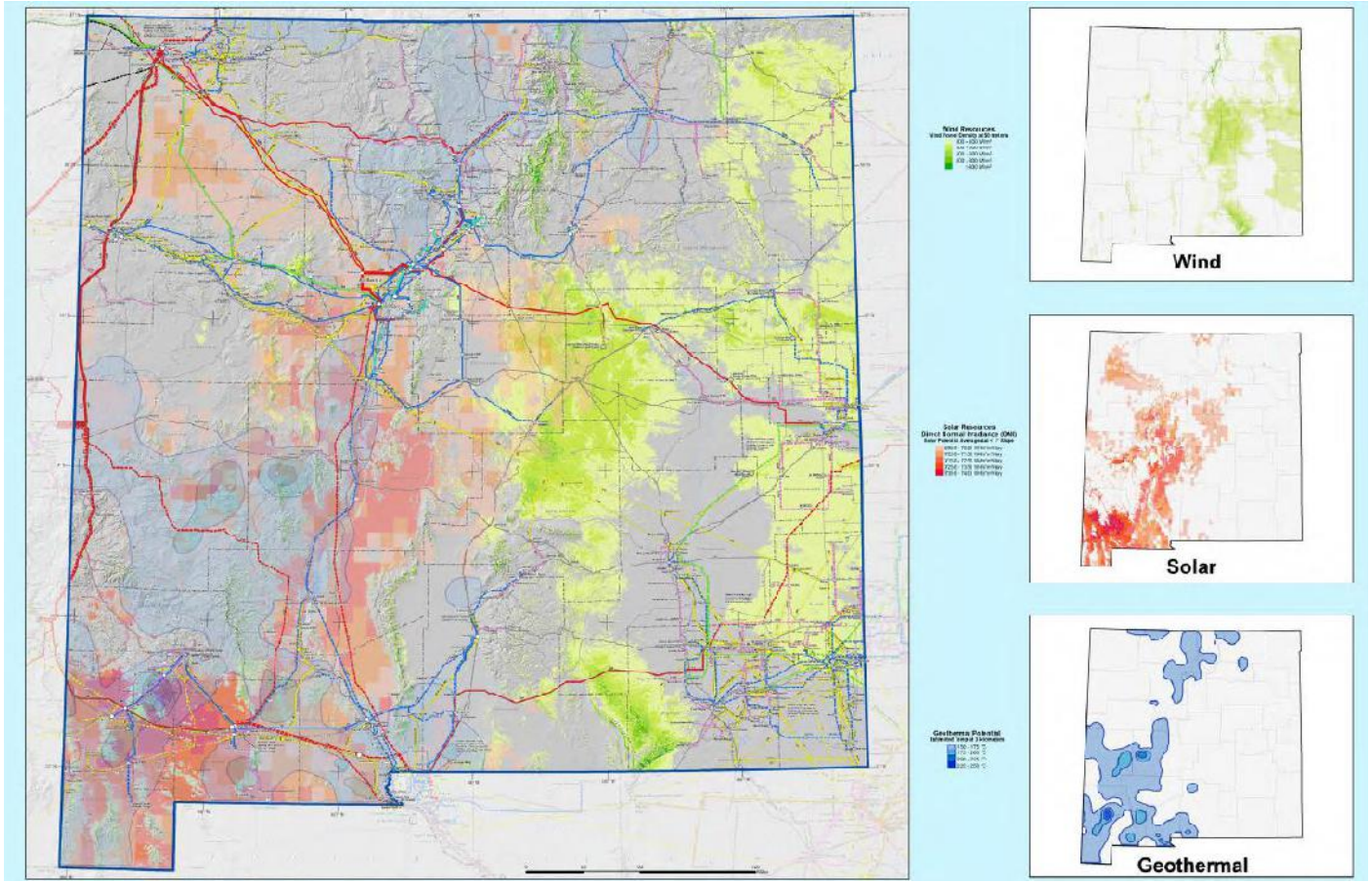
- Primarily shows interconnection points. Generation ties of up to 40 miles may also be part of some requests.
- Larger circles represent more requests
- Darker circles represent more MWs requested.



NEW MEXICO RENEWABLE RESOURCES

- New Mexico is ranked second in the nation for potential solar-generated electric power production and tenth in wind potential.* Western grid rank is higher.

- Access to Eastern NM wind resources is dependent on existing and new transmission facilities.

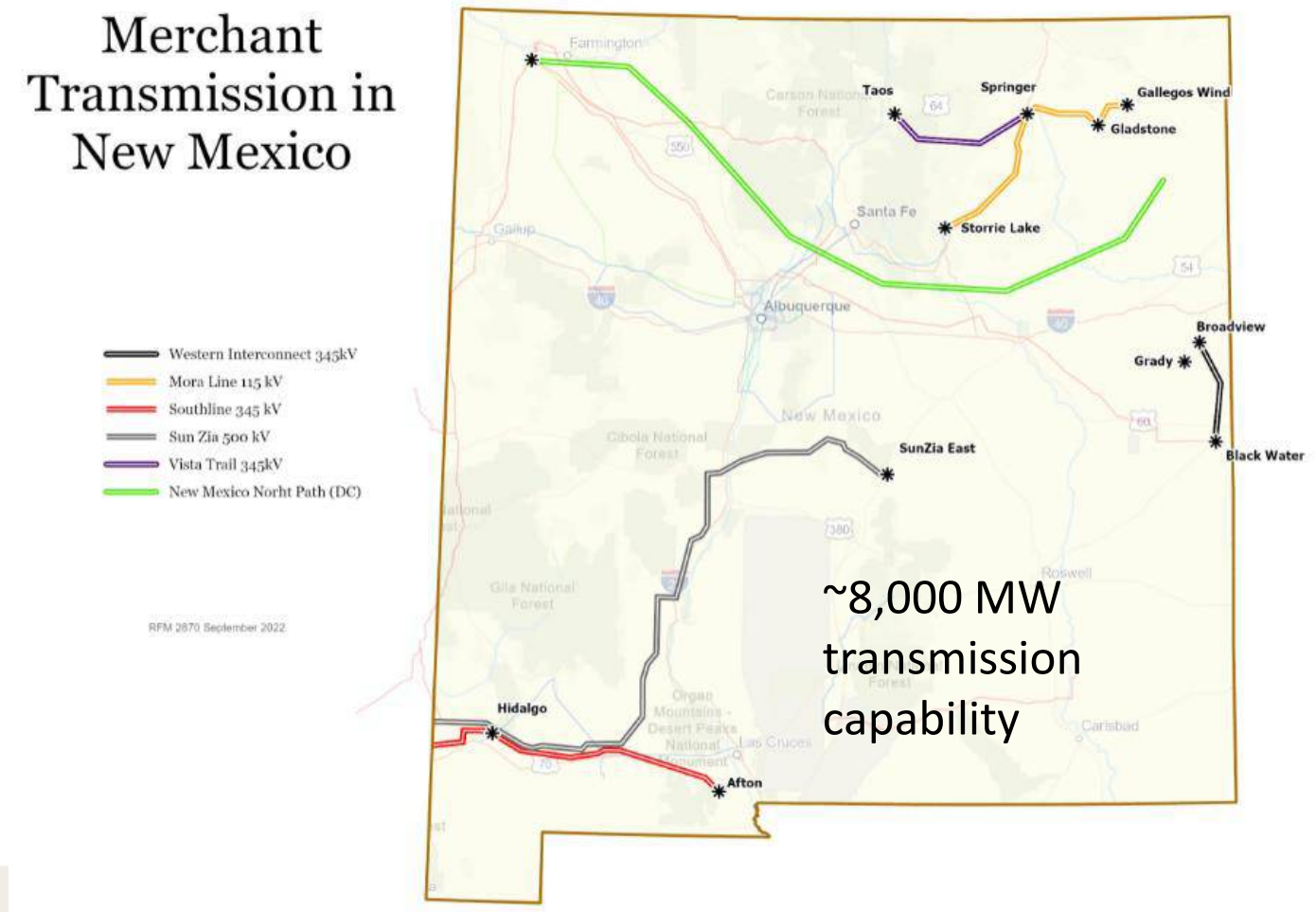


*New Mexico State Land Office
https://www.nmstatelands.org/divisions/commercial-resources/renewable-energy/#:~:text=New%20Mexico%20has%20an%20abundance,and%20tenth%20in%20wind%20potential.

MERCHANT TRANSMISSION IN NEW MEXICO

Will these help NM retail customers?

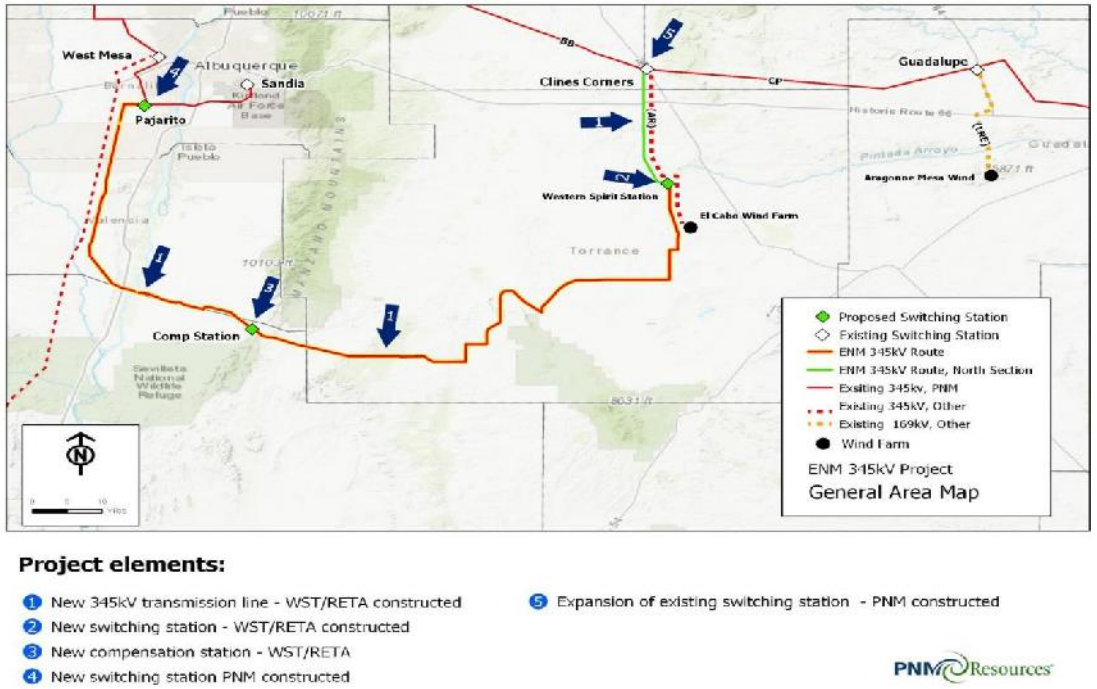
Largest projects are HVDC and may not add load serving capability for retail loads



RECENT TRANSMISSION AND RENEWABLE ENERGY EXPANSION IN NEW MEXICO



- "BB2" Line - 362 MW Incremental Capacity -Second BA-Clines Corners Line - $110M
- Western Spirit Line – 800 MW Incremental Capacity - $365M



Project elements:

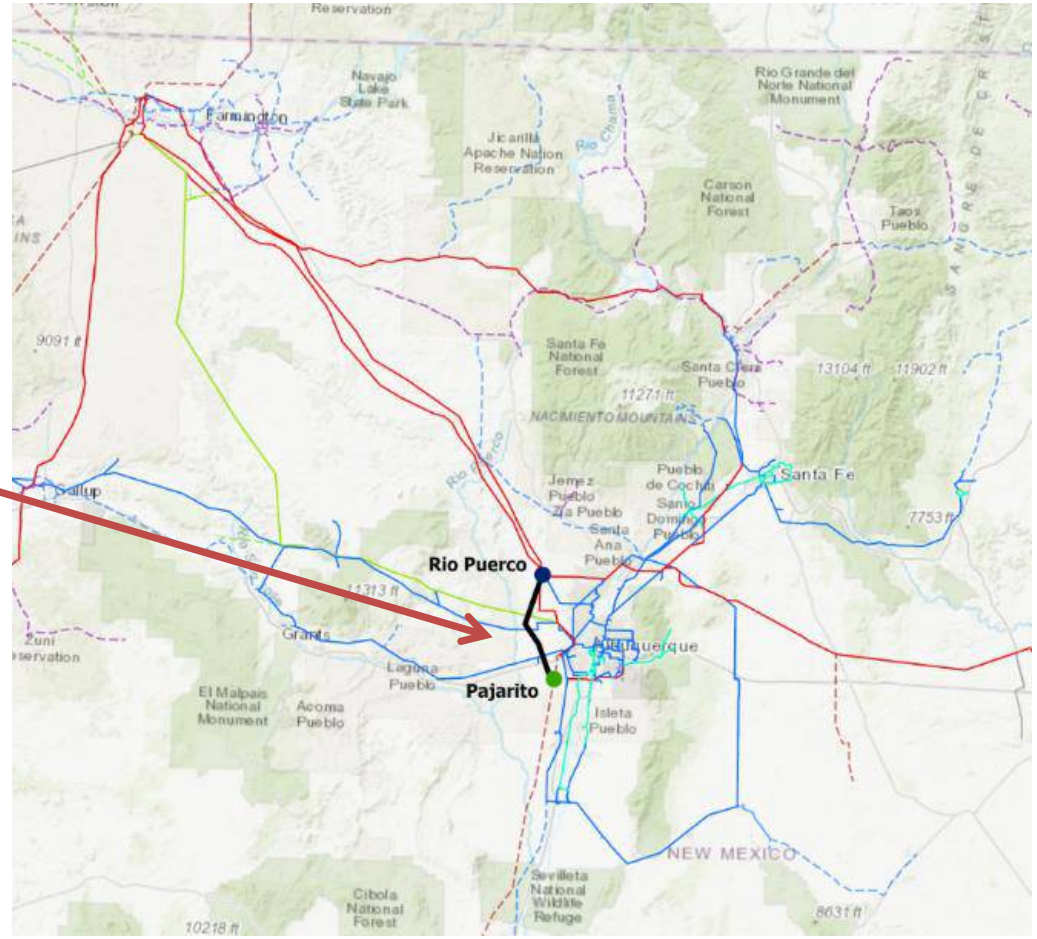
1. New 345kV transmission line - WST/RETA constructed
2. New switching station - WST/RETA constructed
3. New compensation station - WST/RETA
4. New switching station PNM constructed
5. Expansion of existing switching station - PNM constructed

PNM Resources

Both projects improved access to wind resources

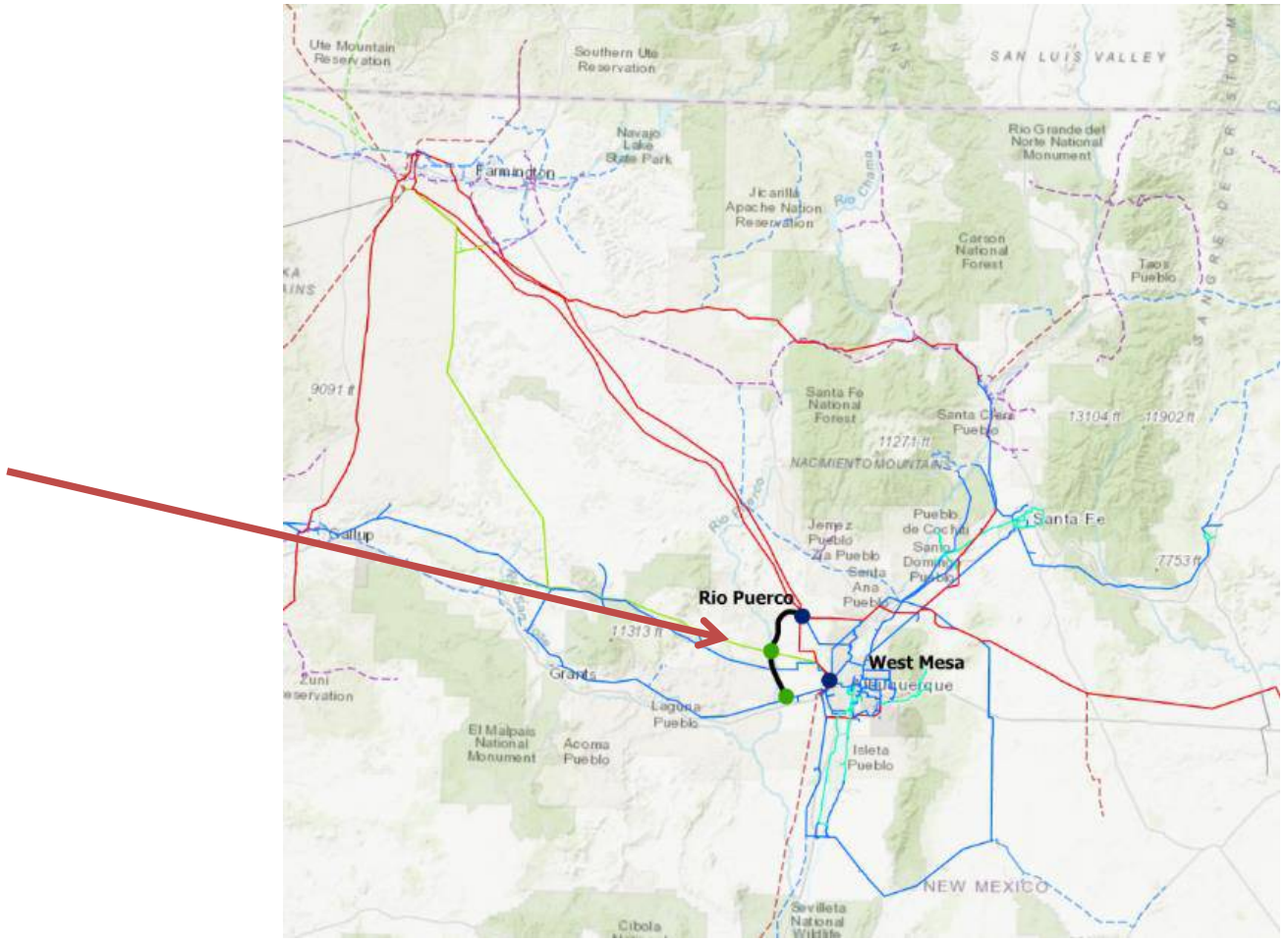
TRANSMISSION IMPROVEMENT FOR ALL OPTIONS

- Expand stations and build Rio Puerco-Pajarito 345 kV line (30 miles)
- Cost ~$90M; Permitting/CCN - 5 years



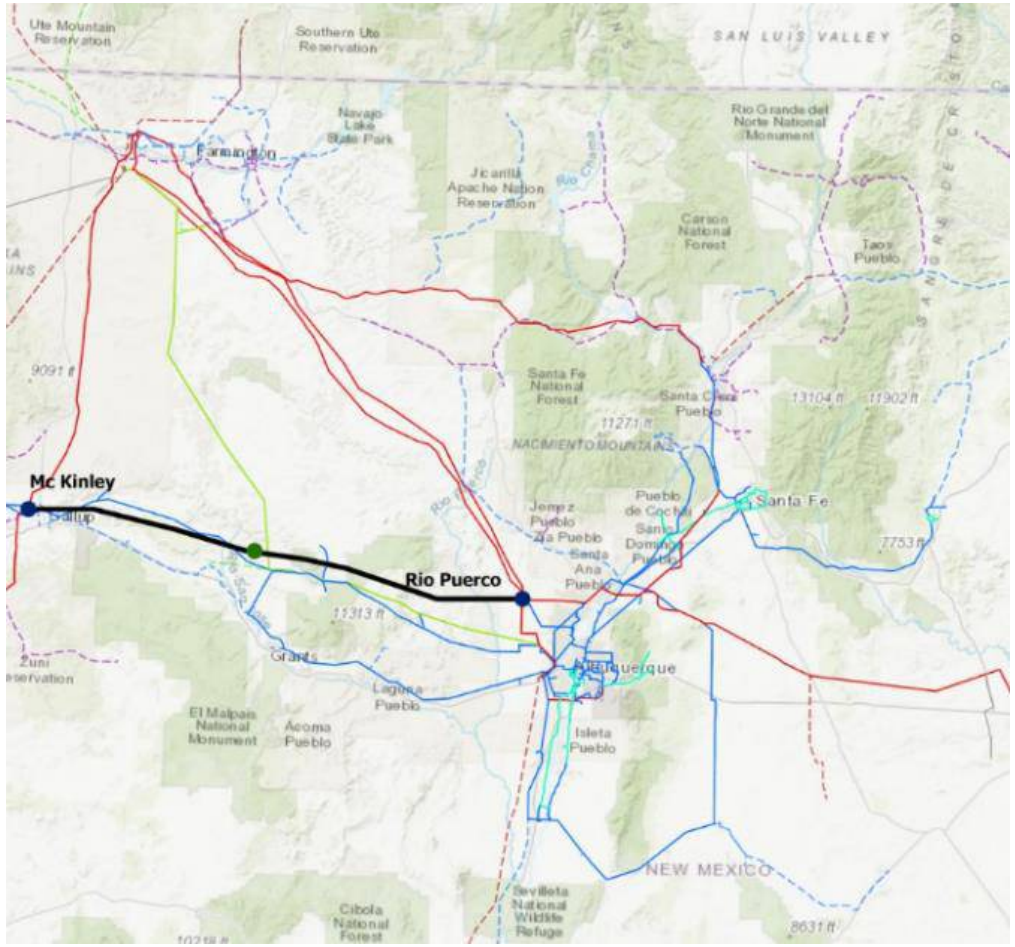
TRANSMISSION EXPANSION FOR WESTERN ABQ SOLAR RESOURCES

- 200 MW
- Expand station Rio Puerco 115 kV station and build 115 kV line from Rio Puerco to two new stations on the KM and BW lines.
- Reconductor/rebuild existing KM & BW lines to West Mesa
- Cost ~$87M; Permitting - 4 years



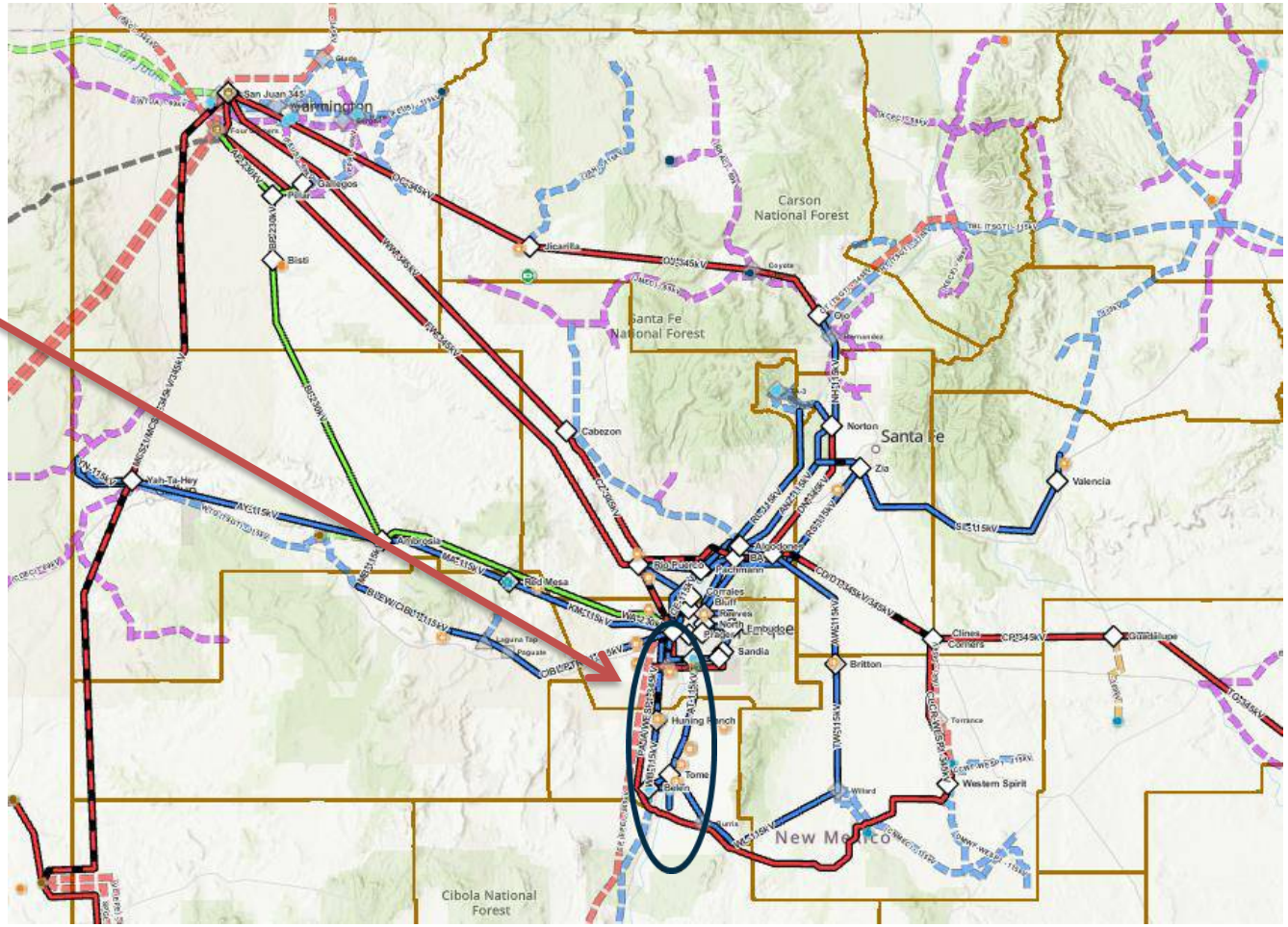
TRANSMISSION EXPANSION FOR WESTERN NM SOLAR RESOURCES

- 600 MW
- Expand McKinley-Rio Puerco 345 KV stations
- Build McKinley-Rio Puerco 345 kV (125 mi.)
- Install two 345 kV switchable shunt reactors
- Install 345/115 kV transformer and new 345 kV &115 kV stations
- Cost ~$442M; ROW/Permitting/CCN- 7 years due



TRANSMISSION EXPANSION FOR SOUTH OF ABQ SOLAR RESOURCES

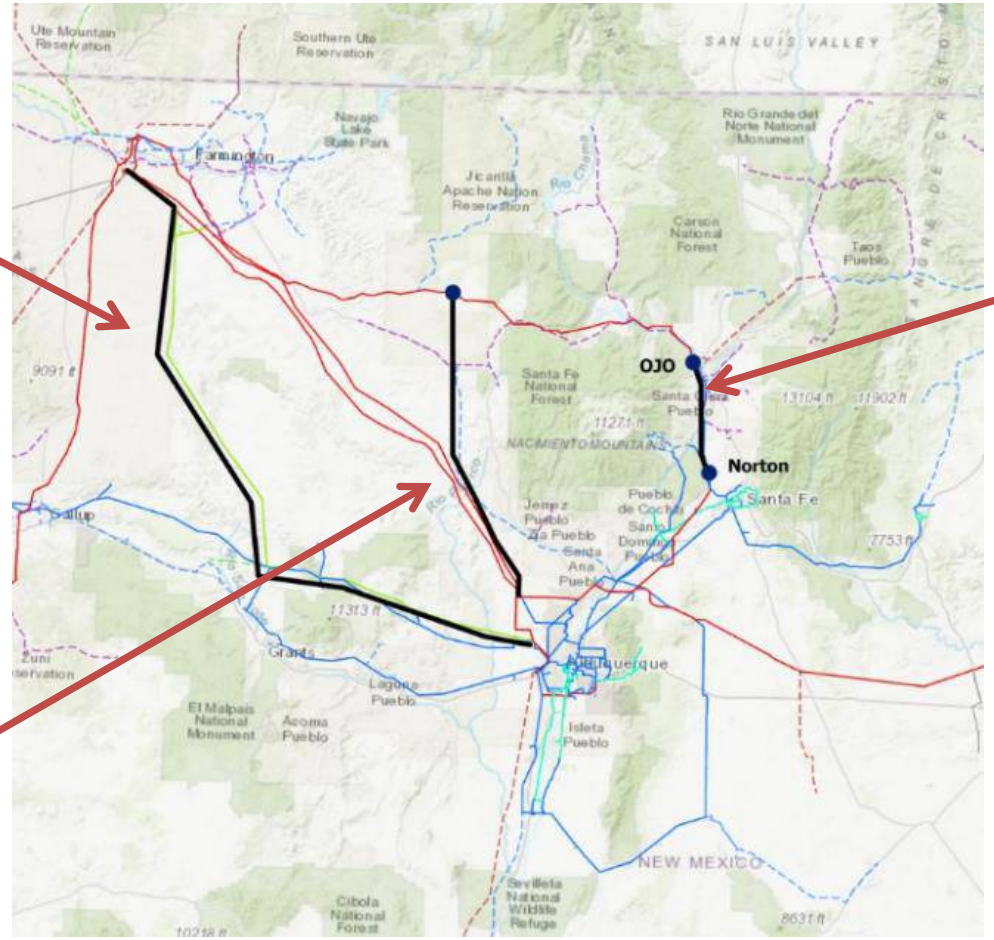
- 200-300 MW
- Convert BP 46 kV line to 115 kV
- Huning-Belen Line Additions
- Cost ~$100M; Permitting – 3-4 years
- Driven by for Sky Ranch Solar



TRANSMISSION EXPANSION FOR NORTHERN NM RESOURCES

- 600 MW
- Expand Four Corners and West Mesa 345 KV stations
- 345 kV stations and 345/230 kV transformers at Pillar, Bista and Ambrosia
- Install two 345 kV switchable shunt reactors
- Rebuild Four Corners-West Mesa 230 KV to 345 kV line (180 mi.)
- Cost $558M; Permitting/CCN- 5+ years

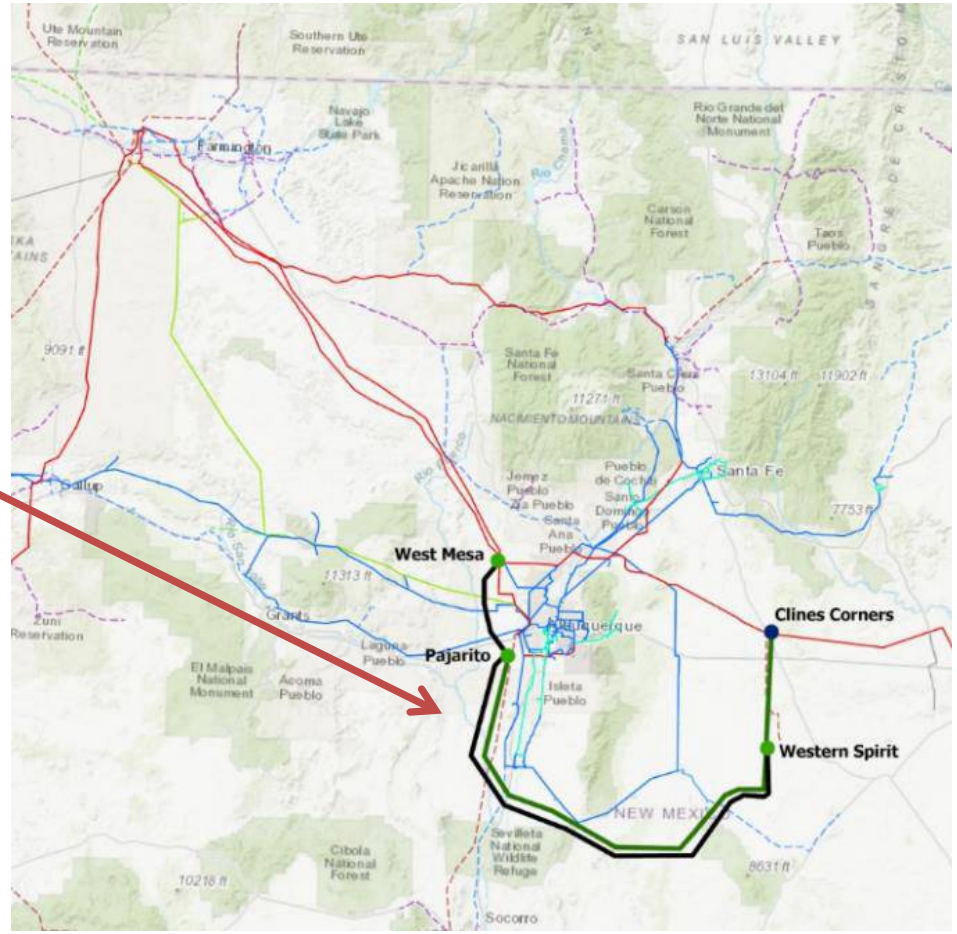
- 600 MW
- Expand Rio Puerco station 345 KV station
- OJ West 345 kV station
- Install two 345 kV switchable shunt reactors
- Build J West-Rio Puerco 345 kV line (80 mi.)
- Cost $232M; Permitting/CCN- 5+ years



- 600 MW
- Expand Ojo and Norton 345 KV stations
- Build Ojo-Norton 345 kV line (34 mi.)
- Cost ~$121M; ROW/Permitting/CCN- 5+ years

TRANSMISSION EXPANSION FOR EASTERN NM WIND RESOURCES

- 800 MW
- Expand Western Spirit & Pajarito 345 KV stations
- Build Western Spirit-Pajarito 345 kV (135 mi.)
- Install 345 kV series compensation
- Install two 345 kV switchable shunt reactors
- Cost ~$373M; Permitting/CCN- 5+ years



Transmission: Regulatory Construct

Laurie Williams

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC)

Develops and enforces Reliability Standards for all users, owners, and operators of the bulk power system in continental United States (Also, Canada and portion of Baja California, Mexico)

- Approximately 880 requirements governing operations, planning, and security (physical and cyber)
- All new and existing transmission *must* meet certain performance criteria designed to ensure grid reliability and resilience
- Reduce hazards to transmission all way from line outages and breaker failures to extreme events, geomagnetic disturbances, and electromagnetic transient phenomena
    - Inverters and lack of inertia fundamentally changing system operations
- NERC requirements regularly audited and can carry fines >$1M/day/violation

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

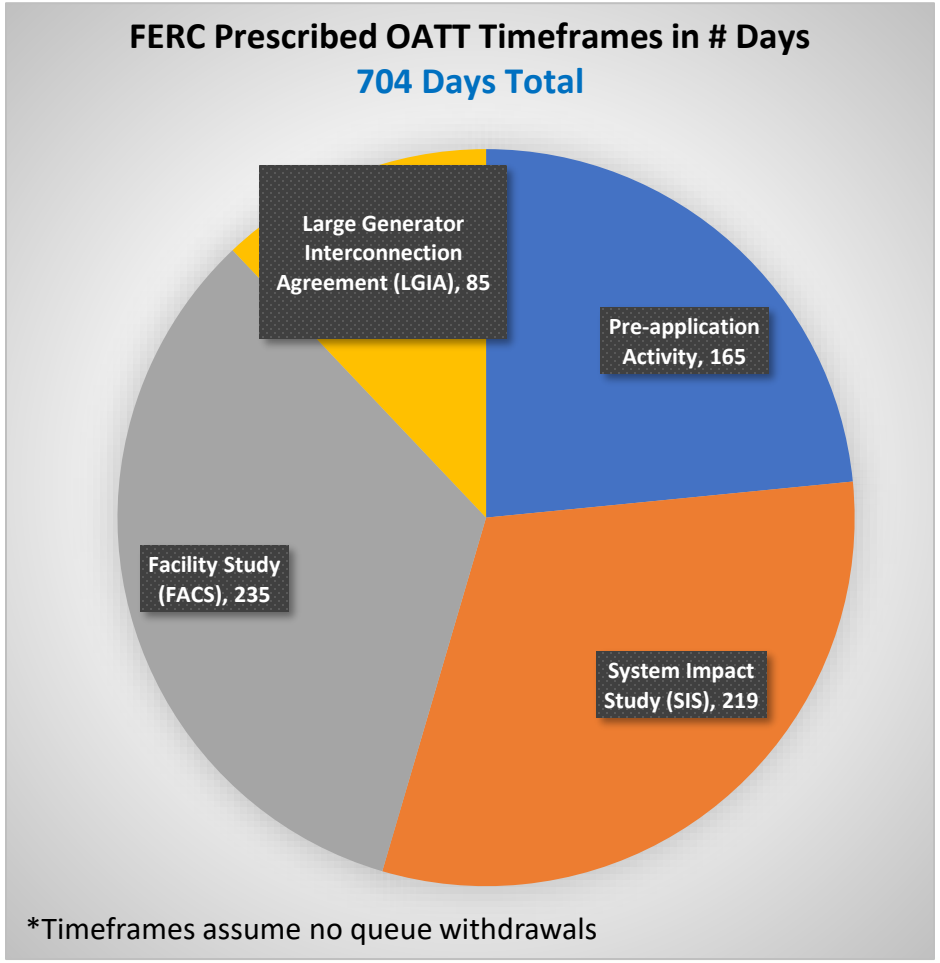


Federal agency that regulates the interstate transmission of natural gas, oil, and electricity

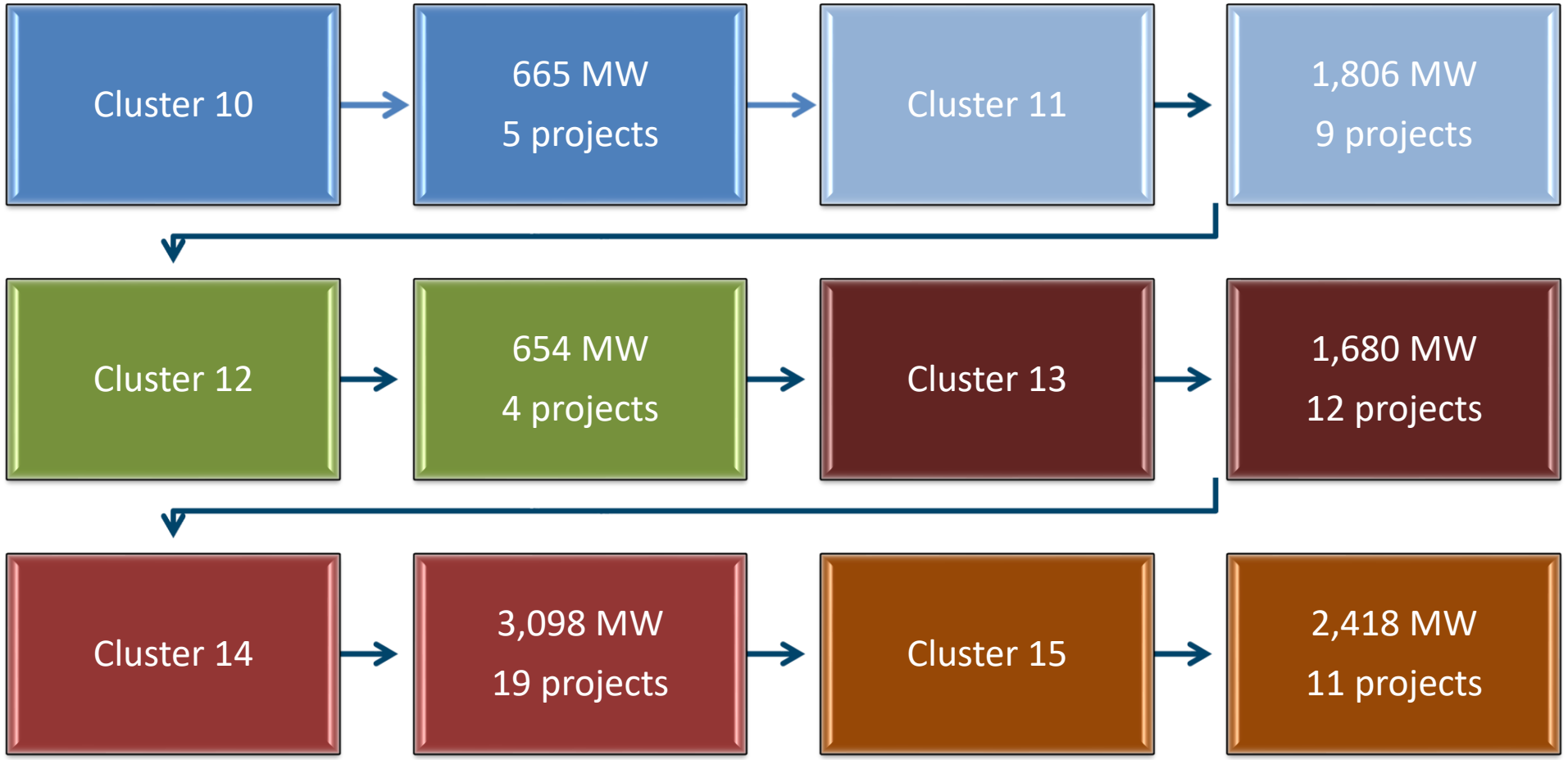
- FERC governs <u>all</u> interconnection and wholesale transmission service for the U.S. interstate transmission grid – including PNM's
- Governance achieved through FERC Orders and codified in Open Access Transmission Tariff (OATT)
- All generators that want to connect to transmission system can if they follow the OATT process
- **Utilities must fund the generator's interconnection facilities to its transmission system and/or provide any requested available transmission service**
- ***Investment focused on specific interconnections thus far to meet FERC obligations***

FERC OPEN ACCESS TRANSMISSION (OATT) PROCESS

- FERC governs interconnection to grid
- Transmission function must treat generation function commensurate with outside developers
- Interconnector has 3 years to provide Notice to Proceed or forfeit queue position
- Timelines are lengthy in large part due to project conception and development
  - Transmission Construction time 18 months – 5 years *typical*
  - Timelines longer due to permitting, access and easement agreements, and Supply Chain



CURRENT FERC LARGE GENERATOR INTERCONNECTION STUDY QUEUES FOR PNM SYSTEM

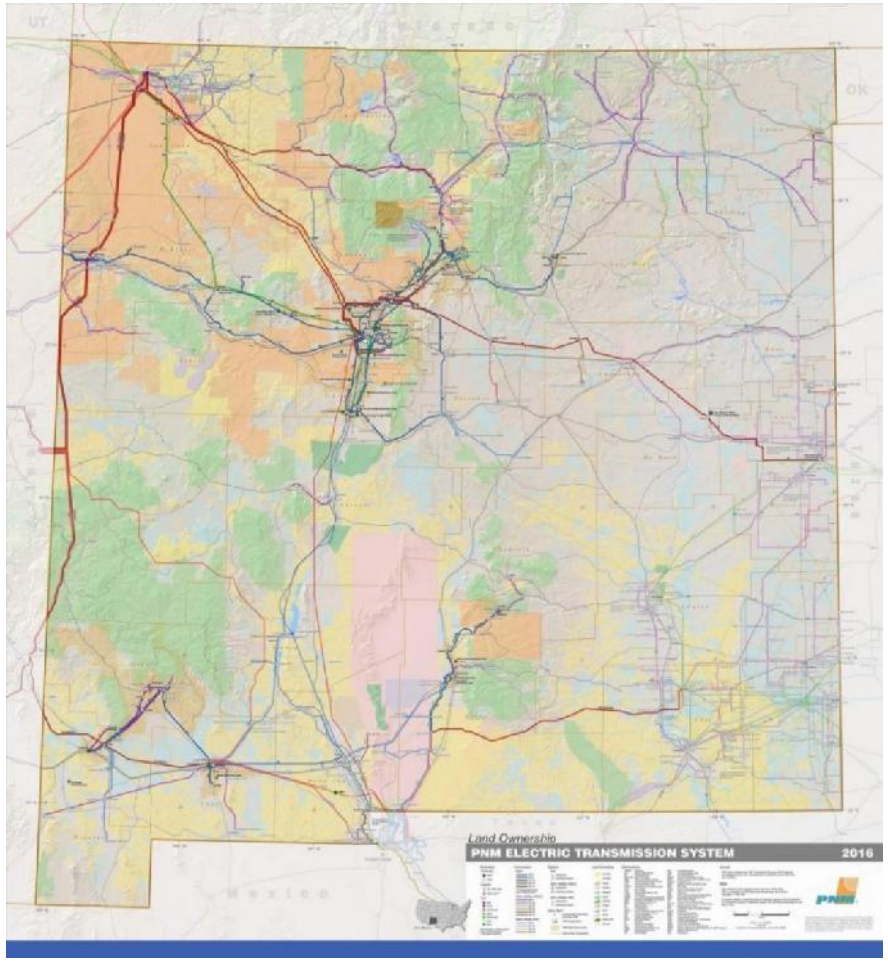


SITING AND PERMITTING CHALLENGES

NM Land Ownership / Management:

- US Forest Service
- Tribal Lands
- NM State
- Military
- US Bureau Land Management

+ Many local, county, city regulatory entities and many private landowners



RENEWABLE ENERGY TRANSMISSION AUTHORITY (RETA)

RETA was created by New Mexico lawmakers to facilitate the development of electric transmission and storage projects. The result is that power can be moved across New Mexico and exported out of New Mexico.

- Established in 2007 to plan, finance, develop and acquire high voltage transmission lines and storage projects in order to promote economic development in New Mexico.
- RETA is one of several state-level transmission authorities in the United States and only the second to have issued Bonds. RETA sponsored projects must transmit at least 30% of its power from renewable resources. RETA's current projects are planned to have 100% of their power originate from renewable resources.
- New Mexico has some of the most extensive and valuable wind and solar resources in the United States yet has limited transmission capacity to access them. RETA was formed to aggressively help develop transmission and storage to cultivate this unique opportunity.
- RETA is working with developers to deliver clean electricity from wind and solar resources to both in-state and export markets.

FROM NM RETA 2021Annual Report
https://nmreta.com/wp-content/uploads/2021/12/Annual-Report_2021_Final.pdf

RENEWABLE ENERGY TRANSMISSION AUTHORITY (RETA)

NM RETA commissioned a Transmission Study in 2020 and an updated its findings in 2022, which included:

- For NM to capitalize on its enormous renewable generation potential, we must find ways to transmit it outside of NM
- **While utility-scale storage technology is developing rapidly, the best solution for New Mexico now is making significant upgrades to our transmission network**
- The most economic approach for customers in New Mexico in the future is to become part of a Regional Transmission Organization
- Developers of new transmission know what to build and where to build it - Laws and policies must be changed to allow this to happen
- Analysis shows that the simplest way to deliver our renewable energy west is with a new transmission corridor across New Mexico
- Built to route power from fossil plants to population centers, New Mexico's grid severely limits renewable electricity delivery to both in-state and export customers, also greatly constraining the development of renewable generation within New Mexico

"Building transmission capacity is key to enabling a renewable energy future."

FROM NM RETA 2022 NEW MEXICO RENEWABLE ENERGY TRANSMISSION AND STORAGE UPDATE
https://nmreta.com/wp-content/uploads/2022/03/010522-RETA-Executive-Summary-FINAL.pdf

ROAD TO A WESTERN RTO

- Members of the Western Markets Exploratory Group (WMEG)
- Twenty-five member participants – encompasses most of west less CA
- Created 2021 - exploring a staged approach to new market services including day-ahead energy sales, transmission system expansion, power supply and grid solutions, and existing and emerging public policies
- Many currently participating in EIM and the ongoing development of day-ahead markets
- Studies to define potential benefits of an organized western market(s)

Arizona Electric Power Cooperative	Arizona Public Service	Avista Corp.	Balancing Authority of Northern California	Black Hills Energy
Bonneville Power Administration	Chelan County PUD No. 1	El Paso Electric Company	Idaho Power	Los Angeles Department of Water & Power
Northwestern Energy	NV Energy	PacifiCorp	Platte River Power Authority	Portland General Electric
Public Service New Mexico	PUD #2 of Grant County	Puget Sound Energy	Salt River Project	Seattle City Light
Tacoma Power	Tri-State Generation & Transmission Association	Tucson Electric Power	Western Area Power Administration	Xcel Energy Colorado

WESTERN MARKET INITIATIVES

CAISO Energy Imbalance Market or “EIM”

Western Markets Exploratory Group or “WMEG

- EIM saved PNM customers $12M in 2021 and project the ~ same in 2022
- A Western-wide ISO/RTO could help continue to leverage resource diversity to lower costs and/or improve reliability for carbon-free grid
- RTO establishment will take several years but must be done on an appropriately diverse scale
  - Smaller market efforts like Mountain West have failed due to insufficient footprint

DRIVERS FOR TRANSMISSION EXPANSION

NERC/WECC Reliability Standards Require Annual Adequacy studies	• Jurisdictional and Network Customer Needs – Core *load growth generally minimal*
Generator Interconnection Procedures (OATT Process)	• Renewable Energy Requirements, La Joya wind, San Juan replacement resources etc.
Transmission Service Requests (OATT Process)	• Avangrid (transmission service from Clines Corners to FC), etc.
Wires-to-Wires Interconnections (OATT Process)	• Western Interconnection, Mora Line, Western Spirt, etc.
Regional Planning Requirements	• FERC Orders 890 and 1000 – Regional Transmission Plan created every 2 years –biannual stakeholder meetings open to public – Notices posted on PNM OASIS – *"Meeting Notices and Meeting Materials"* • WestConnect Mtgs: Posted on WestConnect.com

The IRP/Transmission Challenge and PNM Strategy Going Forward

Laurie Williams

THE IRP/TRANSMISSION CHALLENGE

- IRP's purview includes retail exclusively while PNM's transmission system is used for both retail and wholesale customers
- FERC Rules dictate investment in generator interconnections that are often geographically disparate
    - May not tend toward the best long-term transmission solutions
- FERC Rules prohibit sharing on specific transmission customer information (Non-retail uses)
- Find ways to help drive for regional and more wholistic solutions that meet the needs of the region and all sets of customers



PNM'S TRANSMISSION STRATEGY

- Seek opportunities for regional transmission efforts that increase system reliability and/or enable additional market value and strategic joint transmission expansion.
- Optimize and develop potential increases to system throughput to enable capture of renewable potential in New Mexico. Partner with others to capture NM renewable energy potential for benefit of the region through RETA partnership, WestConnect or other forums.
- Jointly develop and utilize nodal models – transmission constrained economic dispatch modeling to continue to improve evaluation of transmission in the IRP
- Find solutions for operational challenges to system from inverter-based resources using new technology to aid in reduction of harmonics, address the loss of system inertia, and manage charging load(s). Partner with the National Labs/EPRI and others to broaden the expertise to aid in resolution of these technical operational challenges.
- Maximize use of the transmission infrastructure through use of dynamic line ratings and other strategies to maximize potential utilization of current transmission assets.
- Continuously improve the Large and Small Generator Interconnection Processes and ensure the process is within FERC guidelines.
- Participate in policy change efforts with FERC to improve federal interconnection procedures.
- Leverage partnerships with trade organization(s) and neighboring entities to influence FERC and other federal and state policies necessary for timely and comprehensive transmission development to support the energy transition.
- Expand integration of non-wires solutions for the transmission system.
- Pursue legislative opportunities to aid in resolution of substantive challenges for transmission and energy transition.
- Design and build substations and transmission lines with expandability capability.

Transmission presentation to be continued at Steering Meeting #6 on September 28, 2022

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: September 28, 2022

Topic: Public Advisory Steering Meeting #6: Transmission 2/Modeling Inputs 1/Scenario Form

Start Time: 9:00 AM

Location: Virtual

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Transmission

STEERING MEETING #6

OCTOBER 6, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

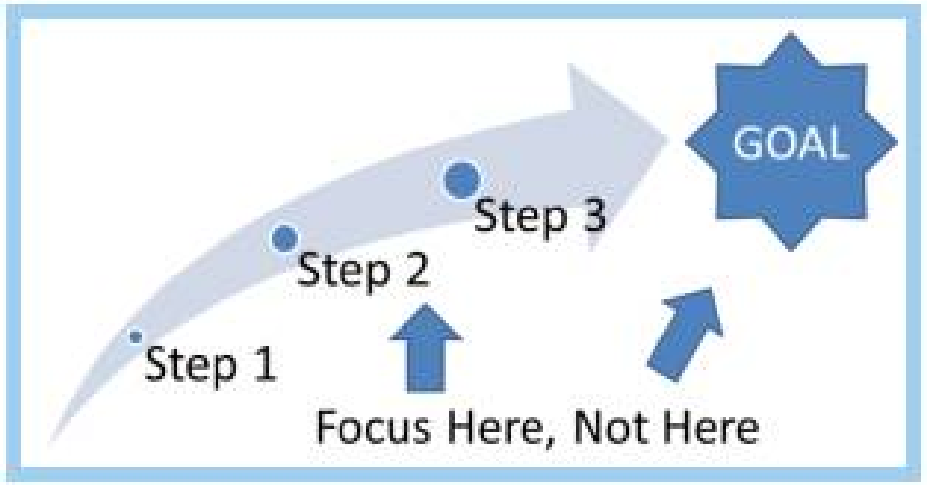
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

AGENDA

PNM Transmission Engineering

- Transmission System Overview
- Role of Transmission in Energy Transition
- PNM's Transmission System and Capability
- Transmission - Regulatory Construct
- The Transmission/Generation Challenge
- Transmission Strategy Going Forward
- Transmission in IRP

E3

- Transmission in Utility Integrated Resource Planning

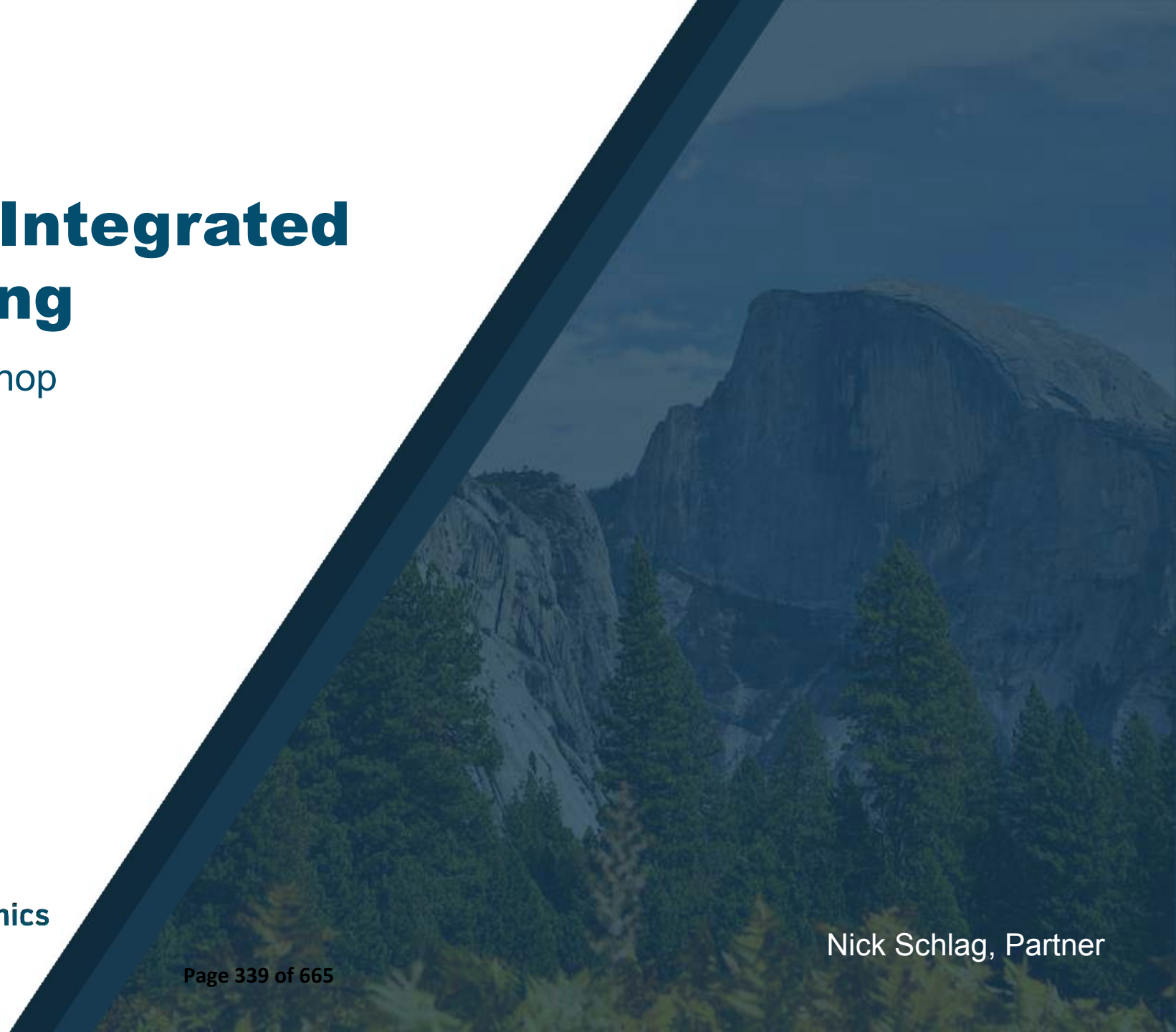
PNM Integrated Resource Planning and transmission teams

- PNM Transmission Modeling for IRP – 2020 & 2023
- Nodal Transmission Modeling

Transmission in Integrated Resource Planning

Presentation to PNM IRP Workshop

October 6, 2022



Energy+Environmental Economics

Nick Schlag, Partner

Emerging need for consideration of transmission in resource planning efforts

- **Utility resource planning and transmission planning have historically been separate processes under traditional planning paradigm**
- **The industry's shift towards variable renewables is an increasing driver of the need for new transmission development and has prompted utilities to increasingly consider how transmission system needs affect their resource decisions**
- **Questions addressed in this presentation:**
  1. How do transmission analysis in IRPs compare with transmission planning studies?
  2. What are the methodologies being used by utilities to account for potential transmission expansion and the associated costs in development of future portfolios?

Conceptual transmission projects identified to deliver renewable resources to load in California's Renewable Energy Transmission Initiative (2009)

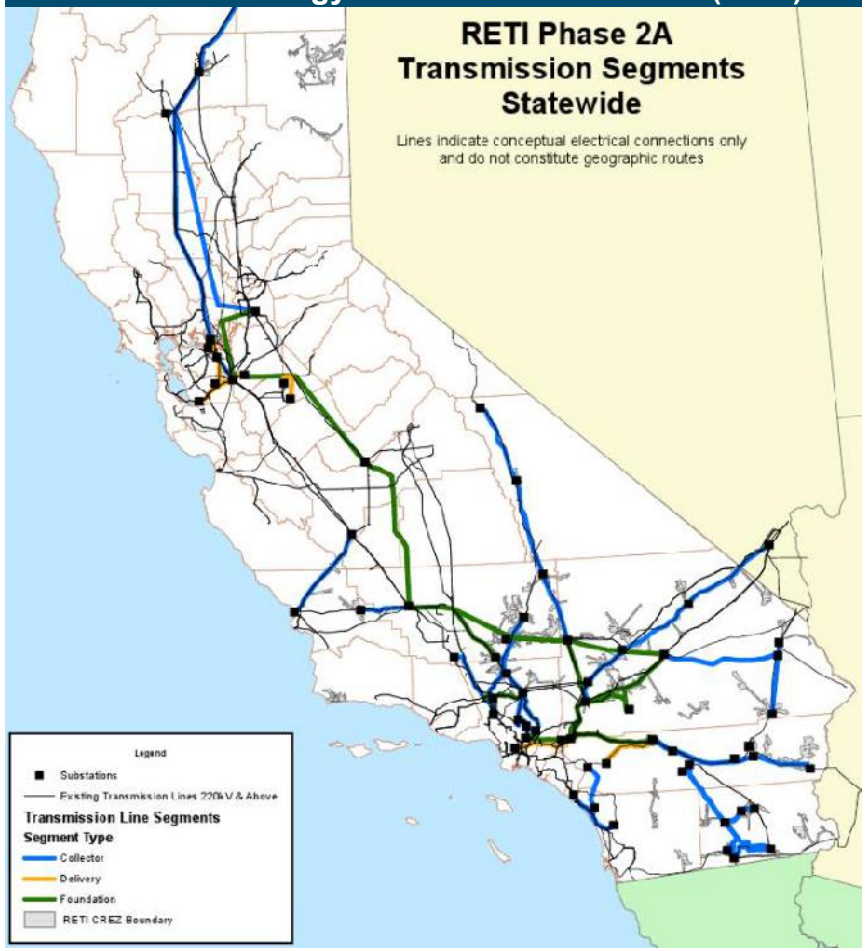


Image Source: Renewable Energy Transmission Initiative Phase 2A Final Report

Transmission in IRPs vs. Transmission Planning

Transmission Analysis in IRPs

+ Transmission analysis in IRPs are typically performed under a ZONAL (pipe and bubble) modeling framework
+ Purpose of the analysis is to ensure resource selection reflects the attendant needs of the transmission system and to allow evaluation of remote resources coupled with transmission expansion as an option – not to directly inform transmission investment decisions

Transmission Planning Studies

+ More detailed NODAL analysis is typically conducted in utilities' transmission planning processes, including detailed resource deliverability study, nodal production cost modeling, and power flow analysis, to support direct resource interconnection and transmission investment decisions



Increased momentum to bring the two ends of the spectrum together and connect the two planning processes (e.g. under the concept of "Integrated System Planning"), however, the concept is still in early-development stage

Three general approaches for incorporating transmission in resource selection & portfolio development in IRPs

All under a zonal modeling framework, with Increasing Complexity

1 **"CREZ"-style cost adders applied to resources or locations**

Methodology: Generic transmission assumptions used to develop cost adders that are applied to resources in capacity expansion modeling
Examples: PNM, El Paso Electric, PSE, PGE

2 **Scenario analysis of transmission projects**

Methodology: Scenarios with and without certain transmission projects are analyzed in resource planning analysis, which allows the planners to compare the benefits and costs associated with those transmission projects
Examples: PacifiCorp, NV Energy, Nova Scotia Power, Idaho Power

3 **Co-optimization of generation & transmission expansion under zonal system representation**

Methodology: Potential transmission upgrade and expansion are characterized as candidate new build options which increase transmission capability between zones with estimated costs in capacity expansion models; resource and transmission expansion are co-optimized in the modeling process
Examples: PacifiCorp, Nova Scotia Power

Use of transmission cost adders is the most common approach to including transmission in IRPs

Utility	Cost Adders	Scenario Analysis	Full Co-optimization
Avista Corporation	✓	×	×
California Public Utility Commission	✓	×	×
El Paso Electric	✓	×	×
Idaho Power	✓	✓	
Nova Scotia Power	×	✓	✓
NV Energy	×	✓	×
PacifiCorp	×	✓	✓
Portland General Electric	✓	×	×
Public Service Company of New Mexico	✓	×	×
Puget Sound Energy	✓	×	×
Sacramento Municipal Utility District	✓	×	×
Xcel Colorado	✓	×	×

Inclusion of cost adders for transmission necessary to deliver new resources common across IRPs

+ **Transmission cost adders applied to resources allow planners to account for costs of transmission in addition to generation resources in the resource selection process**
  - Cost adders may either be resource-specific or location-specific (as in Texas's "Competitive Renewable Energy Zones" (CREZs) or California's RETI process)
  - While costs of transmission are included in resource selection and total cost metrics, the underlying transmission system is often not represented explicitly in the model

+ **Data sources used to inform cost adders drawn from a variety of sources:**
  - Utility Open Access Transmission Tariff (OATT) rates
  - Project-specific transmission cost estimates
  - Generic transmission cost assumptions ($/mile)

Example of CREZ-style cost adders in EPE 2020 IRP

Figure 3-10. Renewable Energy Zones and Transmission Expansion Options

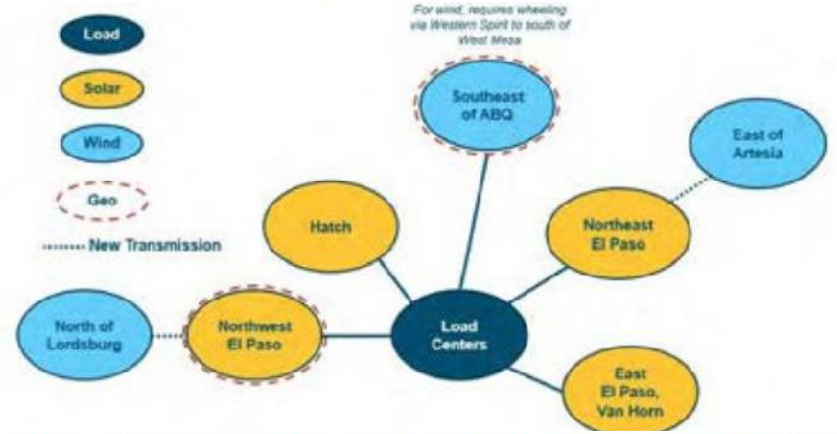


Table 3-7. Transmission Upgrade Costs for Candidate Renewable Resources

Transmission Zone	Downstream Transmission Zone	Assumed Available Capacity Before Upgrades (MW)	Upgrade Length (miles)	Upgrade Voltage (kV)	Upgrade cost ($/kW-yr)[30]
Load Centers	n/a	150	n/a	n/a	n/a
Northeast El Paso	Load Centers	100	75	115	$22.5
East El Paso	Load Centers	100	40	115	$22.5
Van Horn	Load Centers	40	120	115	$30.7
Hatch	Load Centers	40	25	115	$30.7
Northwest El Paso	Load Centers	200	55	345	$55.5
North of Lordsburg	Northwest El Paso	0	50	345	$41.5
East of Artesia	Northeast El Paso	0	200	345	$56.9
Southeast of ABQ[31]	Load Centers	300	125	345	$65.4

Other examples of transmission cost adders in IRPs : PGE 2019 IRP, PSE 2021 IRP, CPUC 2019-2020 IRP, Avista 2021 IRP, SMUD 2019 IRP, Xcel Colorado 2021 ERP

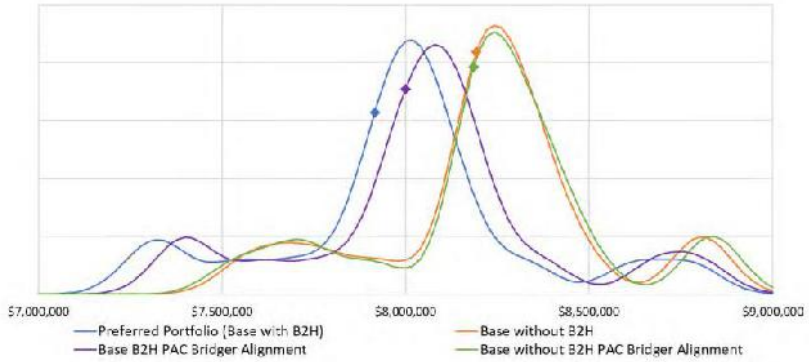
Scenario analysis used to evaluate targeted transmission expansion strategies

+ **Scenario analysis is used in multiple utilities' IRPs to evaluate the benefits and costs of certain strategic transmission projects**
  - Scenarios typically designed surrounding key strategic projects under consideration
  - Allows for detailed examination of the benefits and costs associated with the projects and supports development of action items related to the specific projects of focus
  - Typically coupled with other modeling techniques (e.g. cost adders) to allow better consideration of longer-term generic transmission expansion options

+ **Idaho Powe's 2021 IRP analyzed a comprehensive set of scenarios surrounding two strategic transmission projects – Boardman to Hemingway (B2H) and Gateway West**
  - The analysis demonstrated significant value provided by B2H and identified it as part of the preferred portfolio

Example of transmission scenario analysis in IPC 2021 IRP





Other examples of scenario analysis of transmission expansion: PacifiCorp 2021 IRP, NV Energy 2020 IRP, Nova Scotia Power 2020 IRP

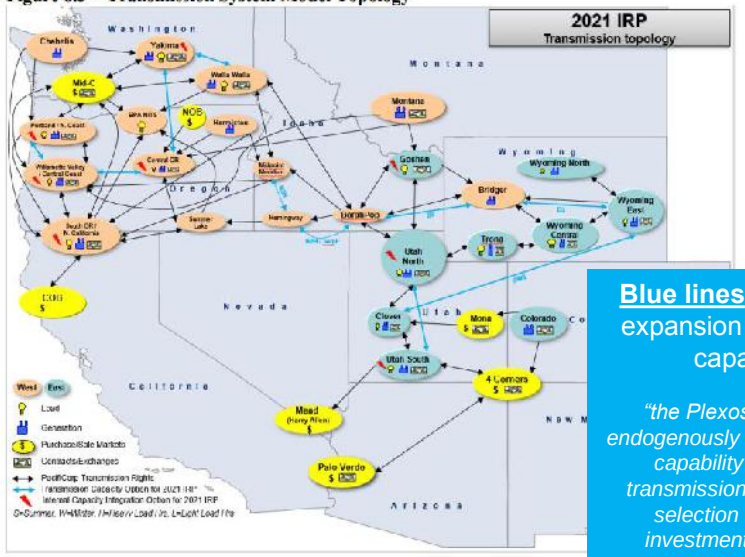
Co-optimization of generation and transmission performed under specific circumstances

+ **PacifiCorp's 2020 IRP uses a detailed approach to modeling transmission that reflects unique aspects of its system (service territory spread across six states and an existing portfolio of resources far from major load centers)**
  - New transmission options capable of increasing transmission capability across zones are characterized in the model and co-optimized with resource expansion
  - Sensitivity analysis layered on top to study the value of several major transmission projects, including the Boardman-to-Hemingway and Gateway South transmission segments

+ **Preferred portfolio identified through the IRP analysis includes detailed transmission investments associated with resource expansion plans; targeted near-term actions developed to facilitate the development of transmission projects identified in preferred portfolio**

Example of Co-optimized modeling in PAC 2020 IRP

Figure 8.3 – Transmission System Model Topology



Blue lines indicate transmission expansion options considered in capacity expansion:

"the Plexos model had the ability to endogenously view costs and transmission capability associated with certain transmission upgrades that allowed for selection of specific transmission investments that coincide with new resource additions"

Table 1.1 – Transmission Projects Included in the 2021 IRP Preferred Portfolio[1,2,*]

Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southern Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery - Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 988 MW of interconnection with 1500 MW of TTC

Tradeoffs among transmission modeling approaches

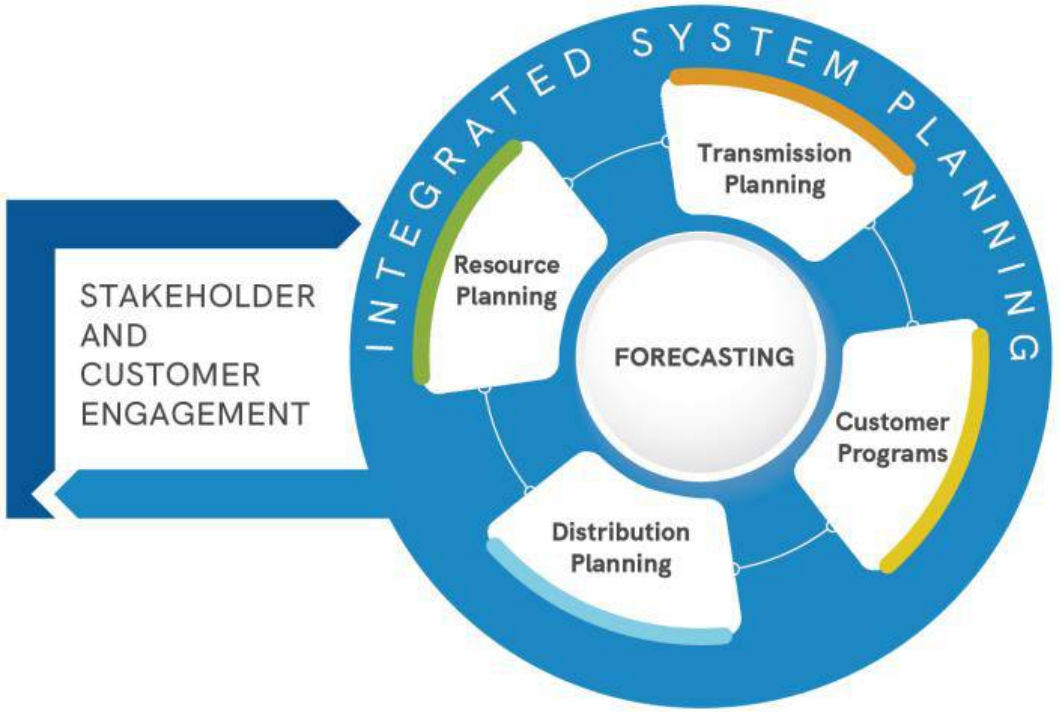
+ **All three methods allow for consideration of transmission costs associated with new resources and essentially provides a framework that allows utilities to evaluate remote resources coupled with potential transmission expansion as an option/strategy in resource planning processes, with different pros and cons:**

Methodology	Advantages	Limitations
Cost Adders	• Can easily be incorporated into any capacity expansion model	• Difficult to capture "lumpiness" of new transmission investments • Only suitable for transmission whose primary benefit is the delivery of new resources to loads
Scenario Analysis	• Provides an explicit quantification of the benefits of a specific project (or set of projects)	• Puts pressure on scenario design to identify the right set of options to study • Difficult to examine generic long-term transmission options when used alone
Co-optimization of Generation and Transmission (under zonal representation)	• Allows for better characterization of resource competition of transmission capacity within a zone and the "lumpiness" of new transmission investments	• Computationally complex to implement; not compatible with all capacity expansion models • Subject to knife-edge effects

Integrated System Planning: the next frontier of coordinated generation & transmission planning?

- **The concept of integrated "system" planning is gaining momentum at a number of utilities**
- **ISP represents a coordinated planning effort that unites multiple planning functions within a utility in a single analytical process**
  - Involves iterative modeling processes and information sharing among groups
- **Multiple utilities have recently commenced their first Integrated System Planning processes:**
  - Salt River Project (Integrated System Plan)
  - Duke Energy (Integrated System & Operations Planning)
  - Hawaiian Electric Company (Integrated Grid Planning)

SRP's Integrated System Planning Framework



Transmission Modeling for PNM IRP

Nick Phillips

Tom Duane

Talk to us.

PROGRESSION OF TRANSMISSION MODELING IN IRP

2011 IRP

- Modeled interconnection and minimal delivery costs for candidate resources (EPRI)

2014 IRP

- Modeled interconnection and minimal delivery costs for candidate resources (EPRI)
- Included wheeling costs for potential market Combined Cycle

2017 IRP

- Modeled interconnection and delivery costs for candidate resources
- Technology specific interconnection and delivery costs refined and included in new resource capital costs (EPRI)

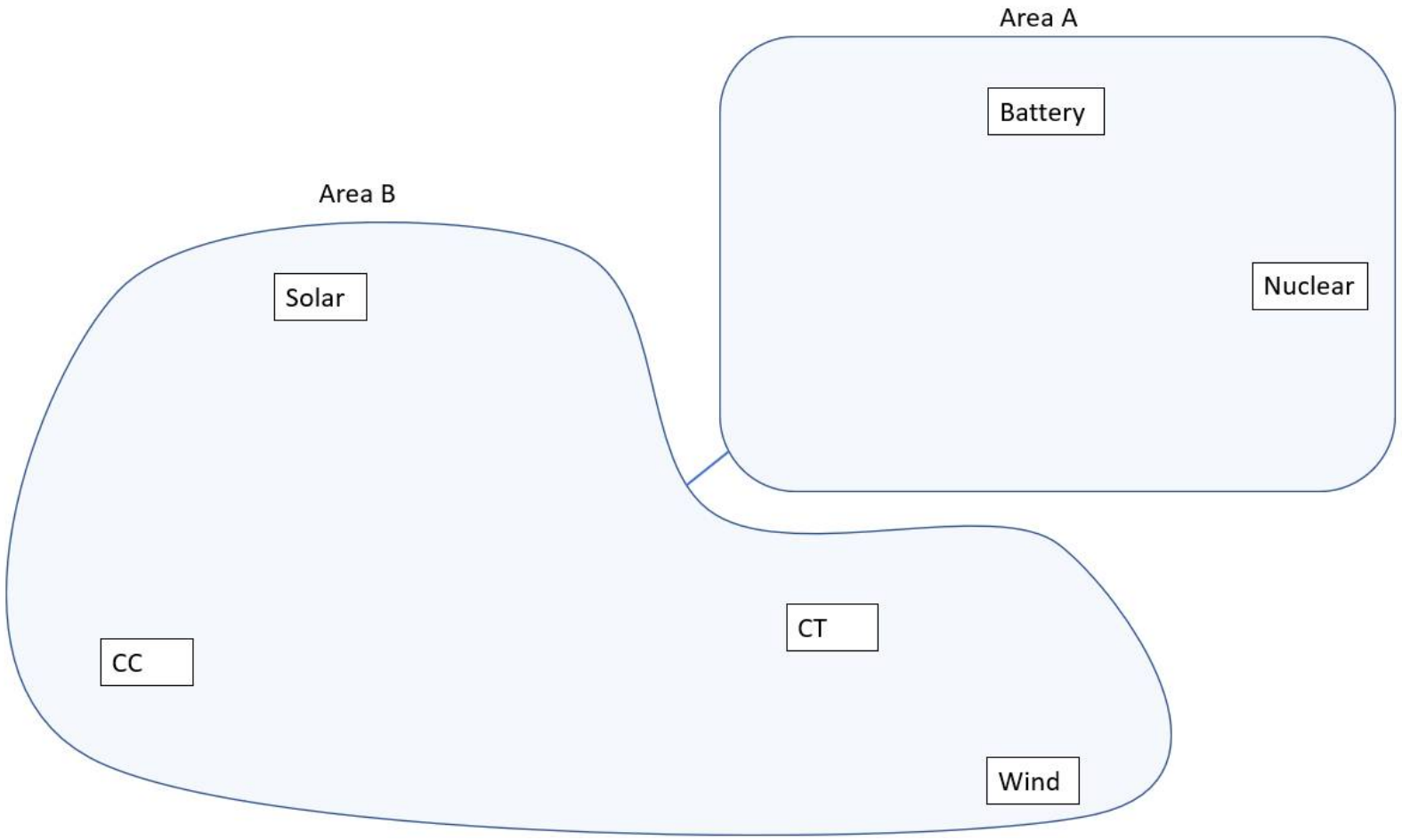
2020 IRP

- Modeled interconnection and delivery costs for candidate resources (EIA, NREL, PNM)
- Proof of concept zonal transmission modeling efforts with potential transmission projects
- Final modeling incorporated transmission cost adders to candidate resources

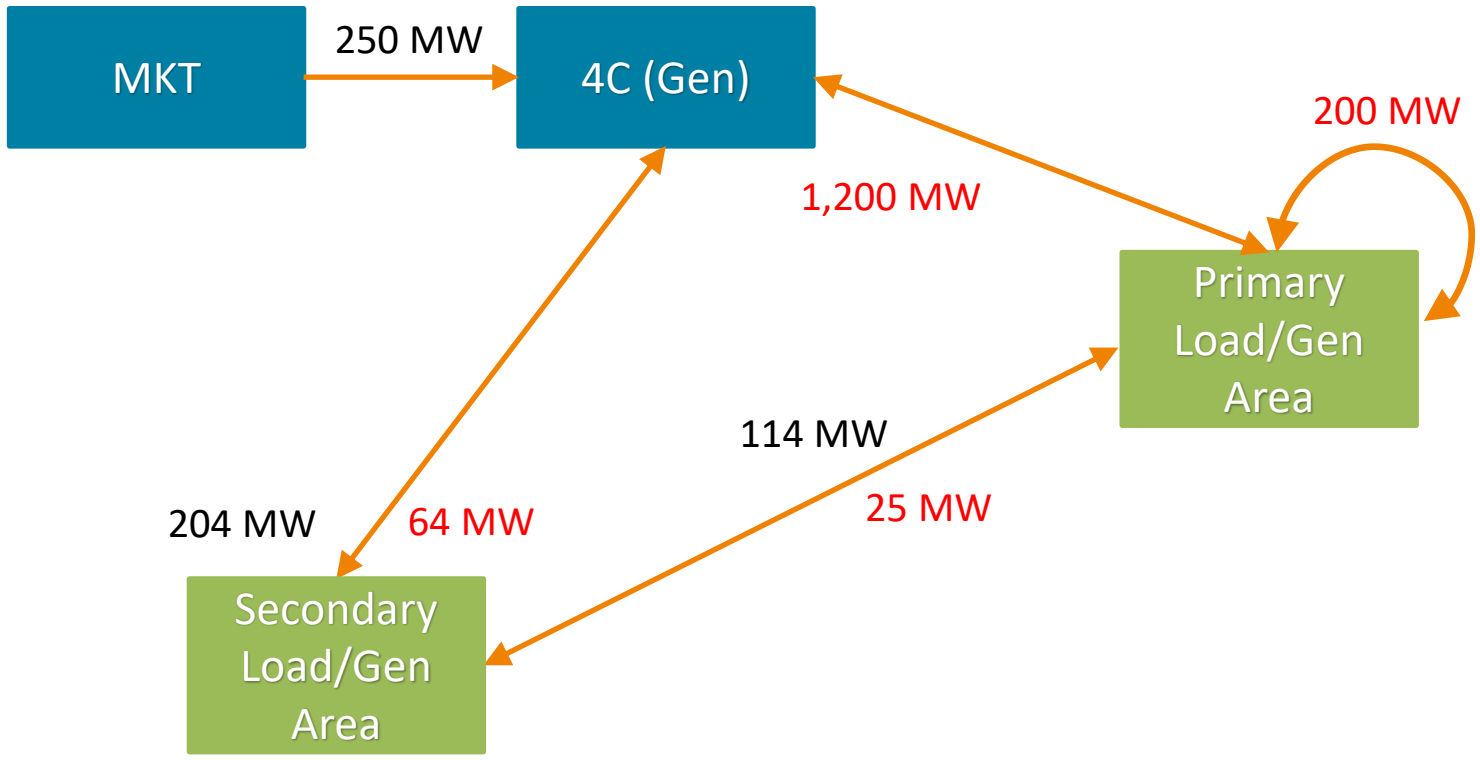
ZONAL TRANSMISSION MODELING OVERVIEW

Zonal (pipe and bubble)

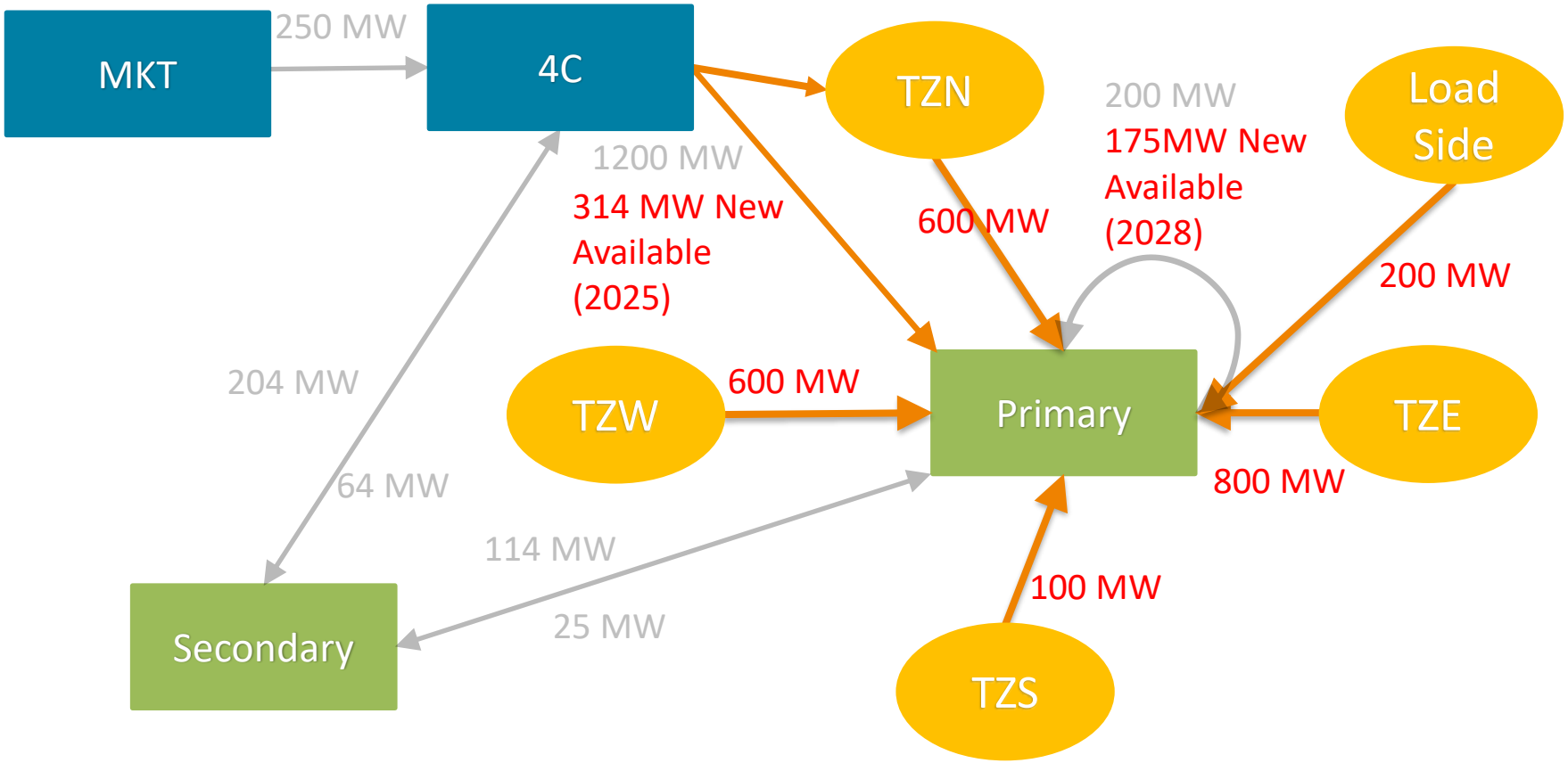
- Portfolio optimization
- Simulating transmission capacity limits and costs
- Environmental compliance
- Long-term study periods (1-20 yrs)



2020 IRP TOPOLOGY – CORE SYSTEM



2020 IRP TOPOLOGY – ZONAL MODELING



PNM Talk to us. PNM.com

2020 IRP TRANSMISSION MODELING EFFORTS

Initial Modeled Topology

- Developed Transmission Expansion Projects Based on PNM Transmission Estimates
- New Generic Resources Added After its Associated Transmission Line is Added
- All Generic Resources Duplicated in Each Area (Except Wind and Pumped Storage)

Pros: More Accurate Transmission Expansion, Shows the "Lumpiness" of Transmission Buildout, Allows for More Efficient Use of Transmission (Solar + Storage)

Cons: Expansion Plan Execution Time ~5X Longer, Transmission Expansion is Limited to Known Options, Could be Less Accurate for Later Years

Final Modeled Topology

- Transmission Costs Modeled Based on a Weighted Average Cost of Transmission Projects
- Each Generic Generation Project Included its Pro-Rata Share of Transmission Cost

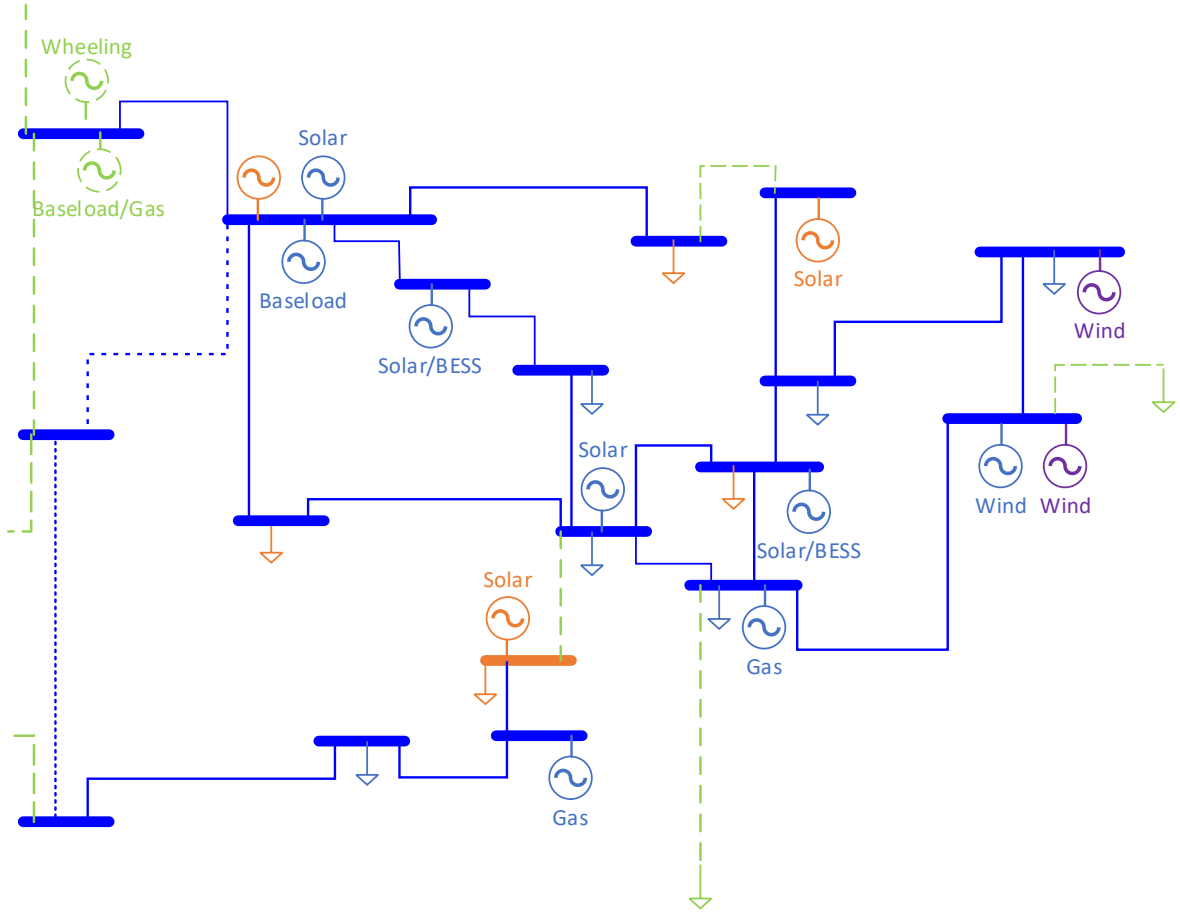
Pros: More Efficient, Informs About Transmission Expansion Needs Through Time

Cons: Less Accurate in the Near Term, Allows for a Smoother Buildout of Generation, Does not Inform About Optimal Location for Generation

NODAL TRANSMISSION MODELING OVERVIEW

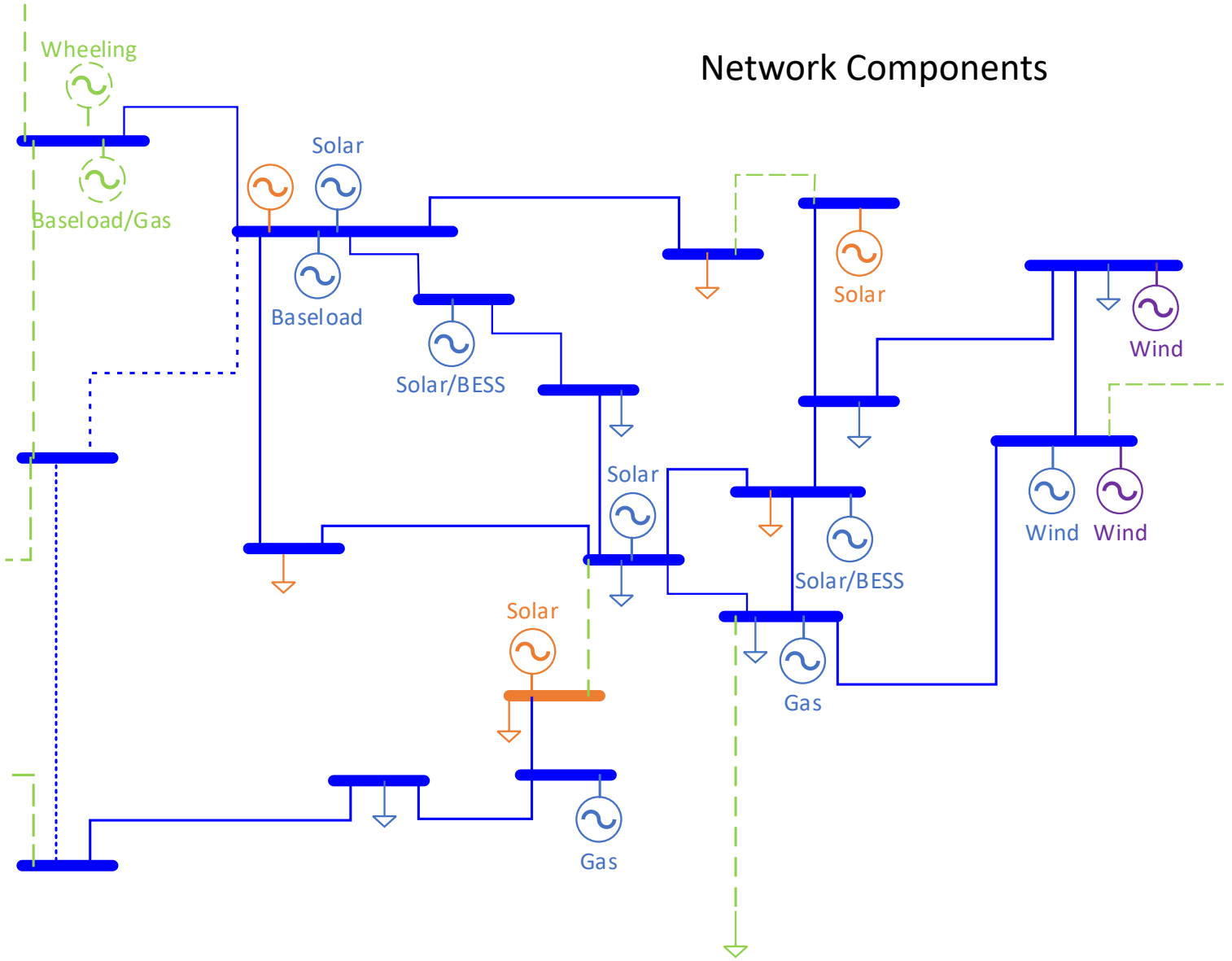
Nodal

- Detailed transmission system representation (DC power-flow) within a given zone
- Accounts for Balancing Area (“BA”) interaction and wholesale customers
- LMP’s for system nodes help determine system congestion
- Transmission outage optimization
- Short-term study periods (1-365) days



Talk to us.

Network Components



Retail Load

Network Customer Load

Wheeling Obligation

Retail Resource

Network Customer Resource

Merchant Resource with Point-Point Wheeling

External Third Party Resource

Transmission

Owned

Jointly Owned

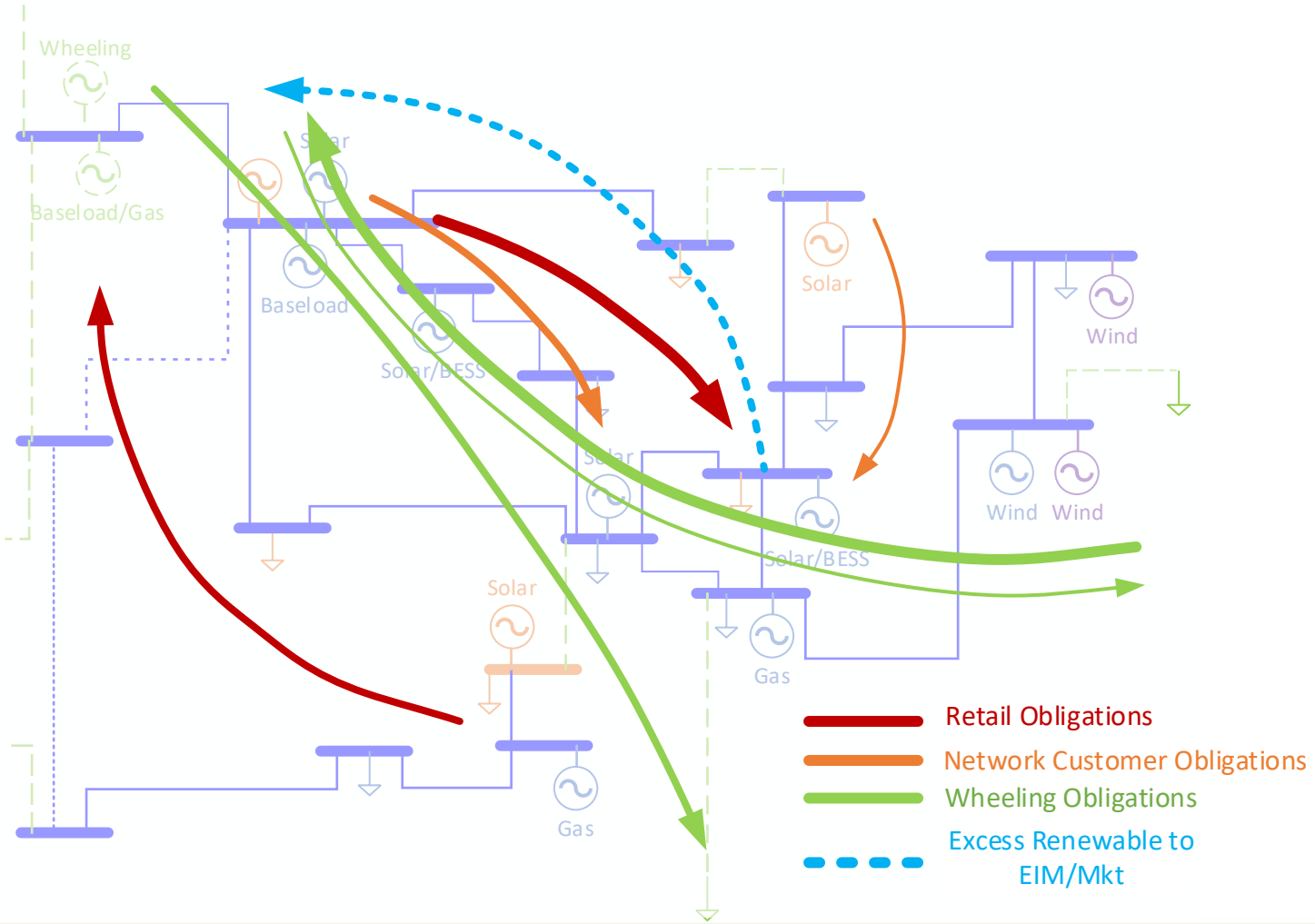
Other Transmission Owner

Talk to us.

TRANSMISSION IMPACTS ARE A FUNCTIONAL OF ALL OBLIGATIONS

Transmission Obligations

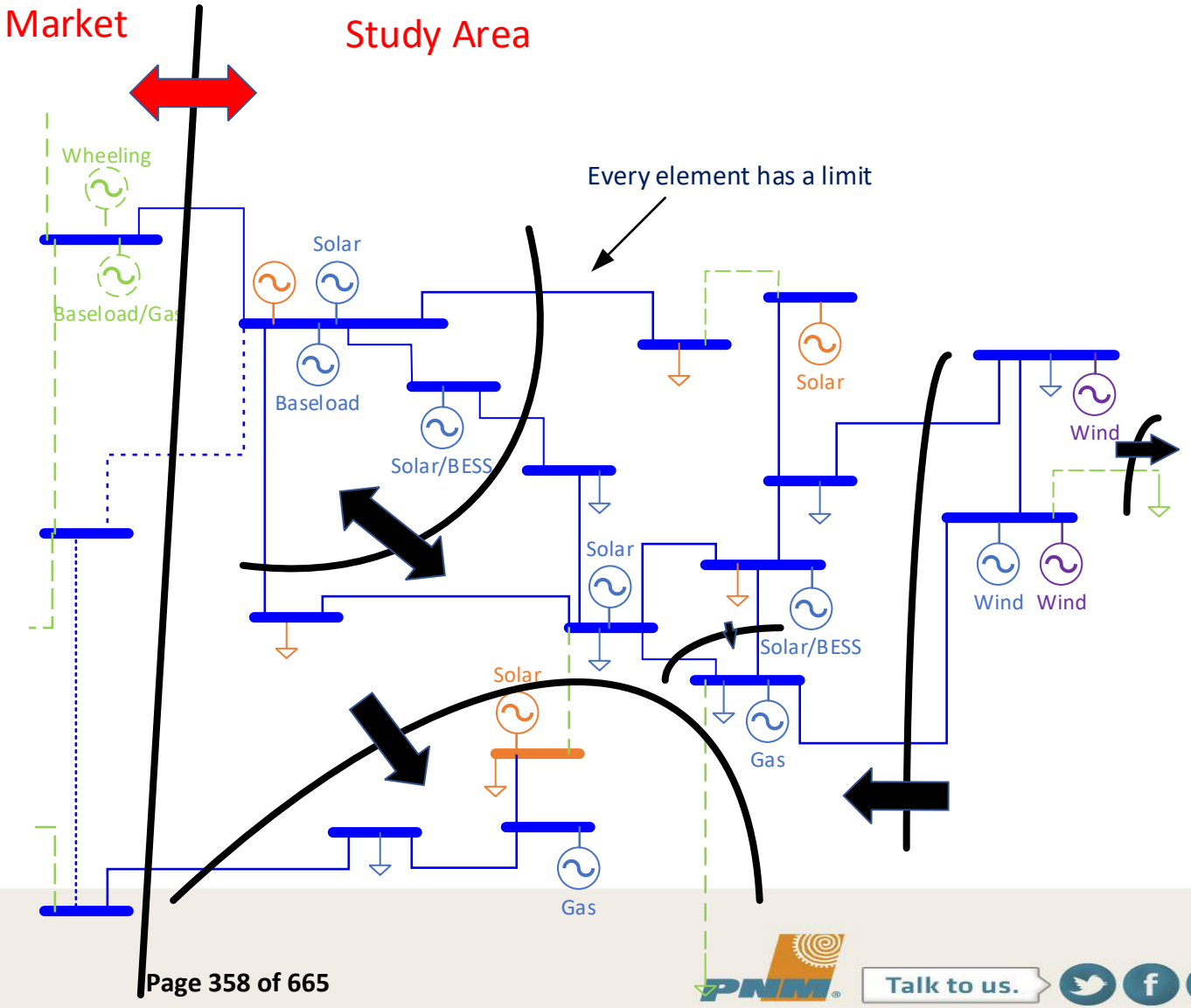
- Transmission flows depend on meeting all obligations.
- Timing of obligations are largely independent – especially wheeling.
- Obligations for renewables are largely unpredictable.
- Transmission must stay within limits regardless of obligations.
- Capacity available for a single user is not easily defined.



Talk to us.

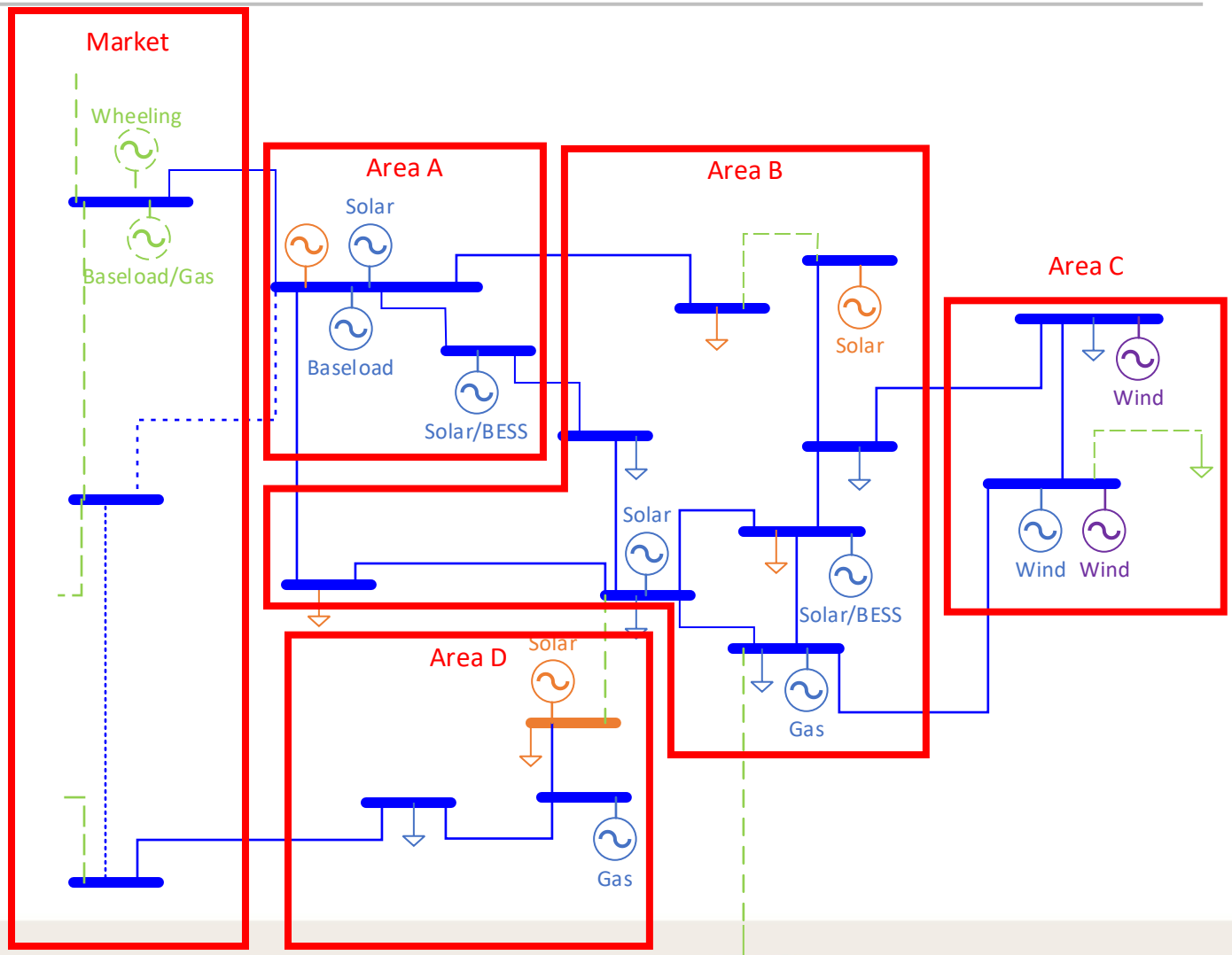
Transmission Limitations

- Every element has a limitation.
- Interface: limitations defined for a set of branches.
- May be possible to reach limit on some elements or interfaces in either direction.
- Interchange and limits with areas outside study area have a substantial impact on results.



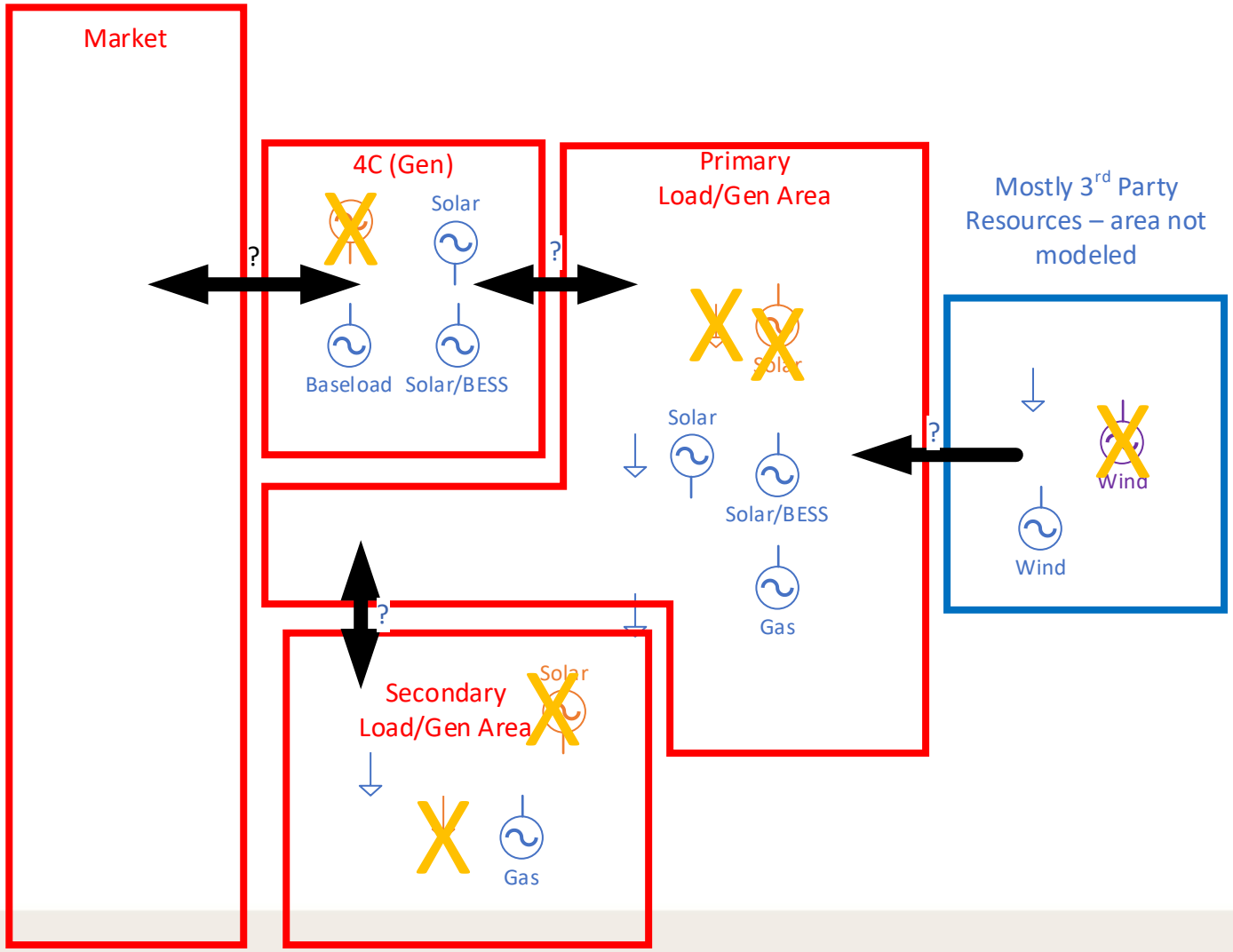
Zonal Areas

- Zonal models require specific geographic areas be defined that include a defined portion of the transmission system.
- Areas are typically based on BA boundaries and known element or interface limitations.
- Limitations between areas are estimated and may not adequately represent physics of system.



Talk to us.

ZONAL MODEL LIMITATIONS



- PNM Load and Resources only modeled historically.
- Requires guessing at amount of transfer capability available for PNM retail.
- Transfers are not representative of actual transmission flows when other obligations are included resulting in potential to overstate or understate congestion.
- Local constraints not captured.
- May help with identifying better information for zonal model topology and transfer limits.

NODAL MODELING

- Overlays the transmission grid (in more detail than pipe and bubble) against the generation dispatch
- Detailed transmission line capability and specific elements of the system assessed on their value to the production cost
- Allows non-retail utilization to be modeled
- Captures the interaction between non-retail customers and PNM retail customers

NODAL MODELING CONSIDERATIONS

Better forecasting of actual transmission utilization and congestion associated with proposed IRP scenarios.

Help optimize storage amounts and locations around unused transmission capacity.

Nodal modeling can capture a greater subset of the transmission customers beyond retail.

Potentially over-optimizes transmission utilization and won't necessarily capture all customer behavior like redirecting transmission rights.

20-year runs will still require a zonal representation due to run-time requirements of nodal modeling.



NODAL TRANSMISSION MODELING

Expanding Encompass model to include a nodal model powerflow overlay

Building other customer data for model for integrate with PNM's production cost database

Model validation required thereafter against expected and neighboring entity interaction(s)

Expected to have preliminary models validated by Q1 2023

Continue to perfect database following runs and results assessments

Guides $Bs in generation and transmission investment, so it must be right!

NODAL TRANSMISSION MODELING: NEXT STEPS FOR IRP

Continue to perfect database following nodal transmission model runs and results assessments

Transmission planning

Use in transmission planning by helping quantify congestion associated with interconnections and transmission service.

IRP

Informs IRP modeling by providing robust framework in which to validate capacity expansion and production cost simulation results

How can resource planning use nodal transmission model results to better inform IRP?

PNM IRP and Transmission teams to further investigate:

- Determine if insights from nodal modeling can help improved zonal representation for full IRP runs.
- Reduced system nodal model – physical power flow representation to improve runtimes
- Other avenues for using nodal transmission model to inform IRP – all options involve testing results against validated nodal transmission model
- Apply to development of considerations in a long-range transmission plan.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: October 17, 2022

Topic: Public Advisory Steering Meeting #7: Emerging Grid Solutions

Start Time: 9:00 AM

Location: Virtual

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by October 12, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



Steering Meeting #7:
Grid Modernization
PNM RFI Responses: Future Projects & Emerging Technologies

OCTOBER 17, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

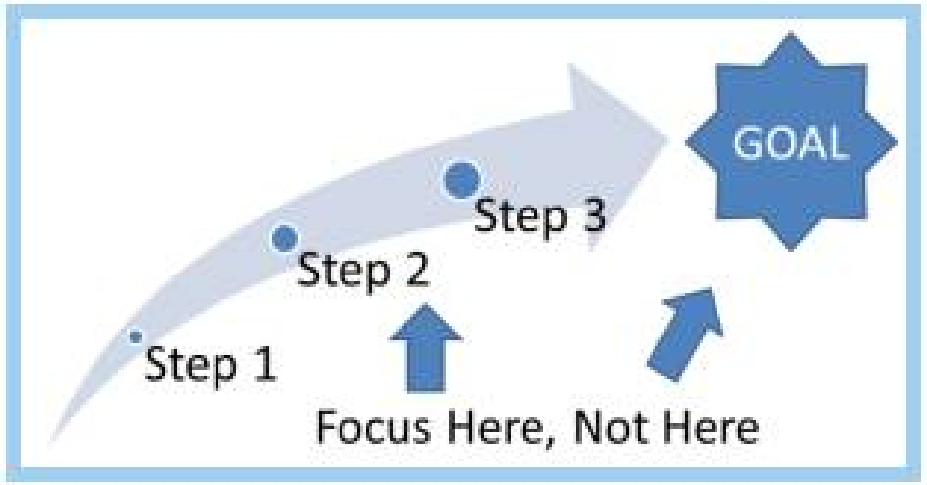
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

- Welcome and Introductions
- PNM Grid Modernization
    - Grid Mod filing
    - Future PNM
- Preliminary RFI Responses
    - Future resources
    - Emerging Technologies
- Next steps and Near-Term Schedule

OUR CUSTOMER FOCUS SETS US APART

We have a Holistic Grid Mod Strategy Driven by Customer Need:

Customer Needs Driven Strategy

- **Value:** Addressing customer needs regarding service value (as opposed to "affordability")
- **Reliability:** Combined with resilience, #1 in customers surveys
- **Sustainability:** Enabling customer options for clean energy and electrification

These 3 needs translate into a set of grid mod objectives:

- **Customer Empowerment:** Enabling customers to manage their energy bill, make informed decisions on pricing, clean energy options and electrification, and provide relevant service information
- **Customer Service Enhancements:** Improving service quality and integration of distributed resources and electrification
- **Reliability Enhancements:** Improving the reliability and sustainability of a more heavily renewable portfolio



HOW DOES GRID MOD BENEFIT CUSTOMERS?

Customer Empowerment	
Customer Energy Management	Detailed usage and price information so customers have more control over when and how they use energy
Service Information	New billing and rate options, like time-of-day, pick-your-own-due-date, and bill alerts. Timely information about power service and status (i.e., outage restoration)

HOW DOES GRID MOD BENEFIT CUSTOMERS?

Customer Empowerment	
Distributed Energy Resources (DER)	Support customers' ability to install onsite renewable energy resources, energy storage, or battery back-up systems
Customer GHG Goals	Make it easier for customers to connect their renewable energy and reduce greenhouse gas emissions
Electrification	Be ready to meet the needs of more electric technologies on the grid, like electric vehicles, HVAC/refrigerated air, and heat pump water heaters

HOW DOES GRID MOD BENEFIT CUSTOMERS?

Service Enhancements	
Service Reliability	Better prevent outages, reduce outage duration, and more-rapidly restore outages when they happen
Service Resilience	Enhance ability to protect against and recover from high impact natural disasters and cyber-terrorism
Safety, Service Quality & Efficiency	Ensure service safety and power quality meets performance standards

DISTRIBUTION SYSTEM UPGRADES



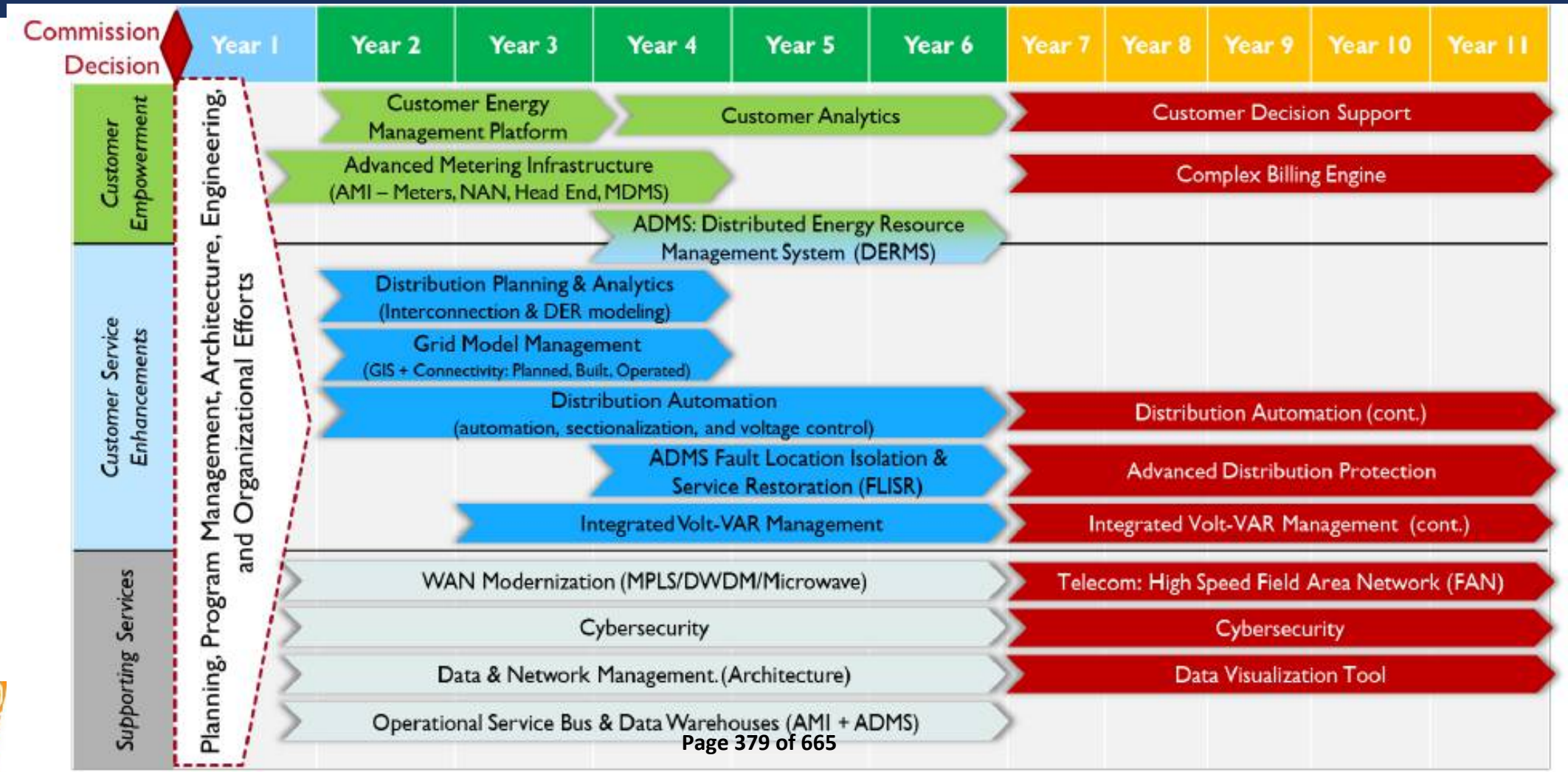
Distribution upgrades in PNM's grid modernization plan will transition the Company's largely aging system into a more advanced digitalized and flexible system commensurate with customer needs and expectations today and into the future.

The specific objectives, include:

- Distributed Energy Resource Adoption
- Reliability
- Resilience
- Decarbonization
- Cost-Effective Deployment

These objectives track the concerns customers highlighted in their feedback.

HIGH-LEVEL GRID MODERNIZATION PLAN



REQUEST FOR INFORMATION SOLICITATION

- The 2023 IRP modeling will be centered around exploring technology options that enable a carbon-free grid by 2040 – analysis will seek to identify trends given system operational needs and how these align with available and emerging technologies
- In July PNM issued two RFIs requesting proposals for technologies to be considered for modeling in PNM's 2023 IRP
    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; these projects have an approximate timeframe of 2025-2030
    2. Emerging Technologies – Technologies that meet PNM's decarbonization goal and that can be fully implemented after 2030 and beyond
- The solicitation concluded on Sept 15, and PNM received approximately 26 proposals
- The following presents a high-level description of each RFI response

RFI DISCLAIMER

The information contained on proposal slides are based on the submittals received or claims made by the developer. The information contained on these slides are for informational purposes only and should not be considered an endorsement or statement of position by PNM and is not intended to reflect the views, positions or responses of PNM. PNM retains the right to determine if the claims are within the scope of RFI and relevant to PNM's IRP. PNM is still undergoing its analysis of these proposals and has not vetted all claims or benefits. Final determination regarding which proposals will be included in the IRP will occur when PNM has concluded its analysis.

RFI RESPONSES – RESOURCES

16 responses from 15 developers

- Aequatis, LLC
- Black Forest Partners
- CSOL Power LLC
- EDF Renewables
- Engie Renewables
- Escalante H2 Power LLC
- Grid United LLC
- K-TEK International
- Kinetic Power
- Morse Associates, Inc.
- Plus Power, LLC
- ReneSola Power
- rPlus Hydro LLP
- Uplight Inc
- Wallis Energy Corporation

Resources Types

- Concentrated solar power
- Demand response software
- Parts fabrication and services
- Pumped hydro storage
- Solar + battery hybrid
- Thermal energy storage
- Transmission

BLACK FOREST PARTNERS

Technology Type: Transmission

Description: Double circuit high voltage transmission line connecting southern NM to Southern AZ

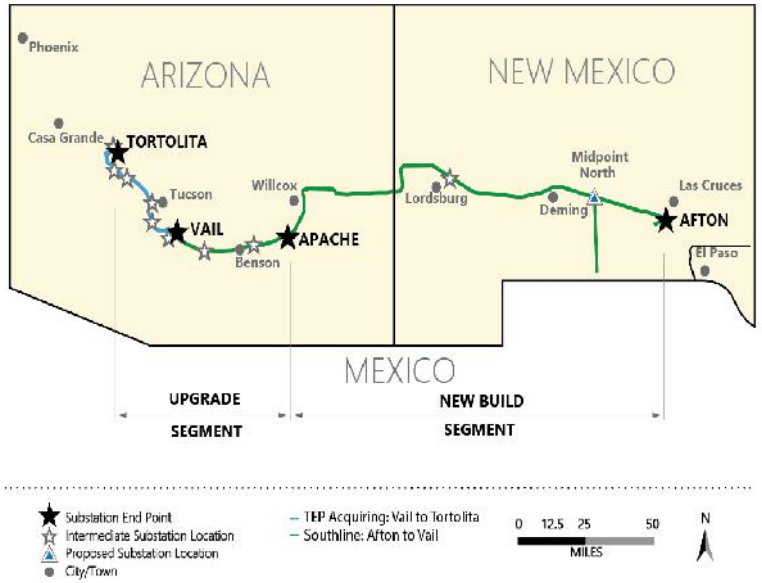
Project development status: development ongoing

Details:

- New 345kV bidirectional transmission line from Afton, NM to Tucson, AZ
- Fully permitted with estimated operational date Q4 2027
- Two sections:
    - 240 miles new 345 kV double circuit transmission lines between Afton and Apache substation
    - 120 miles transmission upgrades to 230 kV double circuit lines between Apache and Tortolita substations

Provides:

- Access to high quality renewable projects
- Improves connections for EIM
- Connects PNM southern resources to 4C
- Expands PNM access to long term corridor



Source: www.southlinetransmissionproject.com

CSOL LLC

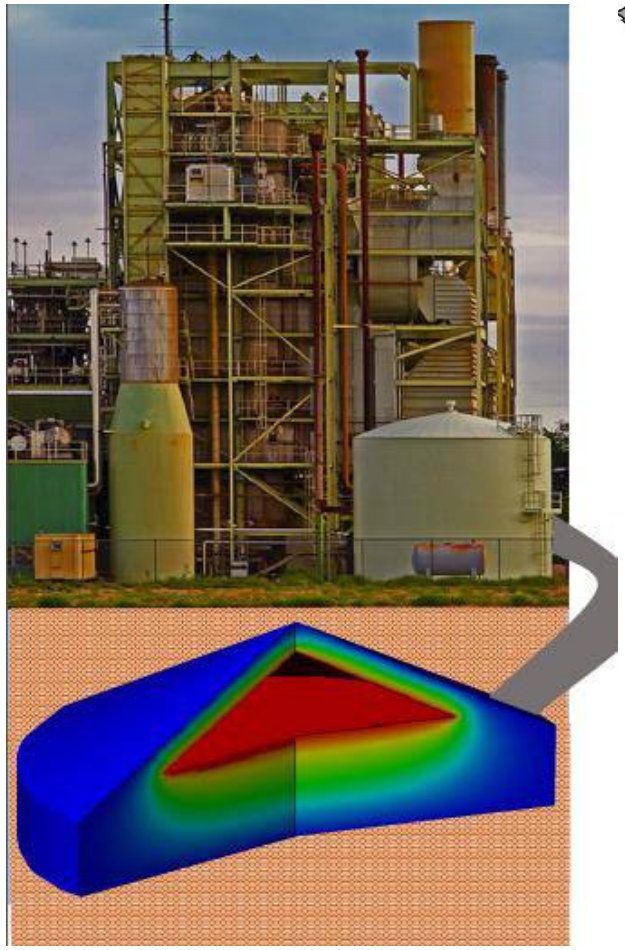
Technology Type: Thermal Storage

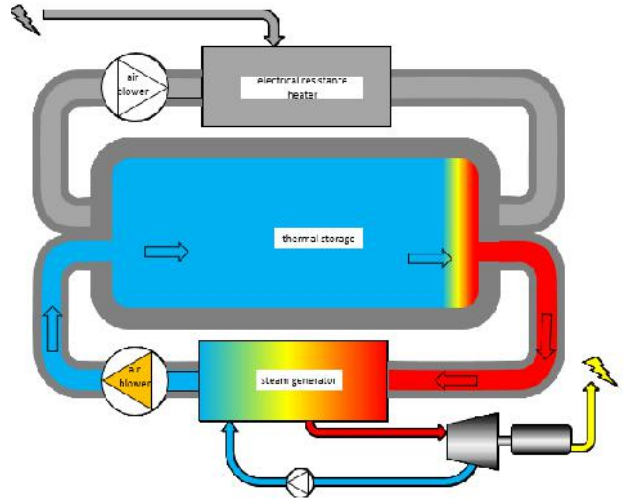
Description: Underground thermal storage that stores a high temperature (650 C) using geomaterials (such as basalt and quartzite gravel, or fabricated refractory materials); facility will use blown air to transfer heat to steam generator for use in a pre-existing steam turbine

Technology Readiness: proven, though this particular design has not been implemented

Benefits:

- No emissions
- Developer claims it is more efficient that battery storage
- Repurposes fossil fuel power plants for generating power
- Can provide steam for industrial process/residential heating applications depending on where it is sited
- Doesn't require additional transmission infrastructure





Source: www.csolpower.com

Talk to us.

EDF RENEWABLES (I)

Technology Type: Solar/Energy Storage

Description: three new large scale solar hybrid/battery projects located in southwestern US

Project development status: development ongoing

Details:

Project 1 – 200 MW solar/200 MW Battery energy Storage
- Sited in McKinley County, NM
- Estimated COD Q4 2026

Project 2 – 500 MW/500 MW Battery energy Storage
- Greenfield site in southern NM, Hildalgo County
- Estimated COD Q4 2027

Project 3 – 500 MW Solar
- Sited in Apache County, AZ; phased project
- COD: Phase I Q4 2024; Phase II Q4 2026



Maverick 6 &7 under construction *Source: EDF Renewables*

PNM Talk to us. PNM.com

EDF RENEWABLES (II)

Technology Type: Solar PV

Description: new solar facility located in Albuquerque

Project development status: development ongoing

Details:

- 50 MW Solar PV facility
- Expected COD Q4 2025
- Sited in Bernalillo County
- Greenfield site

ENGIE

Project: Solar PV/Battery Storage

Technology Type: Solar/Energy Storage

Description: three new large scale solar hybrid/battery projects

Project development status: development ongoing

Details:

- Large-scale projects (200+ MW)
- Estimated COD in the targeted RFI timeframes

GRID UNITED LLC

Technology Type: Transmission intertie

Description: high voltage direct current transmission line

Project development status: expected COD in targeted timeframe; HVDC systems represent a relatively mature technology that have been successfully deployed around the world

Details:

- Fully controllable bi-directional resource

Benefits:

- Access to diverse renewable resources outside southwest region
- Increased interregional reserve capacity, reliability



DC transmission facilities in the US (various owners/operators)
Source: Grid United

K-TEK INTERNATIONAL

Technology Type: Parts fabrication, service provider

Description: 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.

Project development status: N/A

Details: Marketing products and brochures

Benefits:

- Complete HRSG supply chain network with decades of fabrication experience and global supply record
- Applied Mechanics unit staff comprised of licensed P.E.s
- Offices in US and Korea – open 24/7

KINETIC POWER

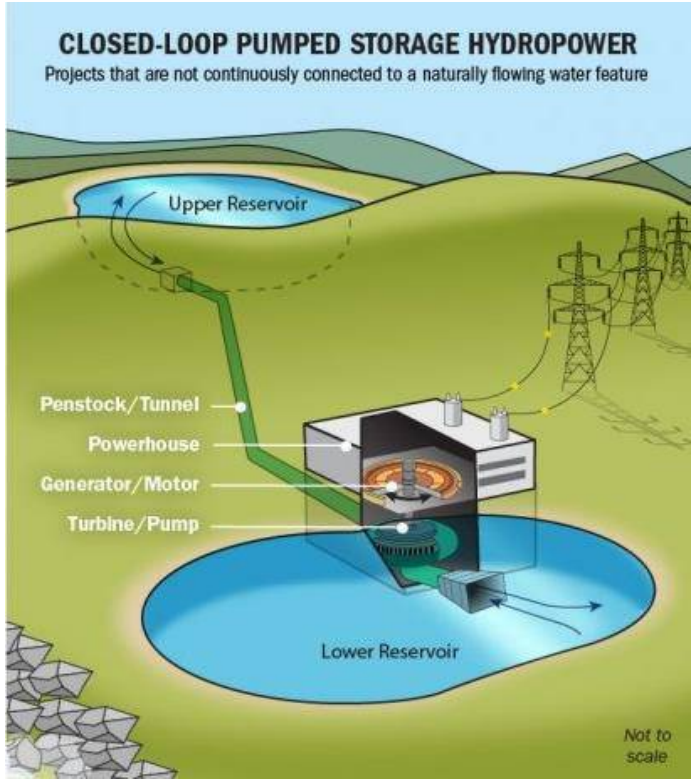
Technology Type: Pumped Hydro Storage

Description: new pumped storage project near the Four Corners

Project development status: development ongoing

Details:

- Sized at 1,500 MW with 70 hours of duration



Source: www.energy.gov

MORSE ASSOCIATES, INC.

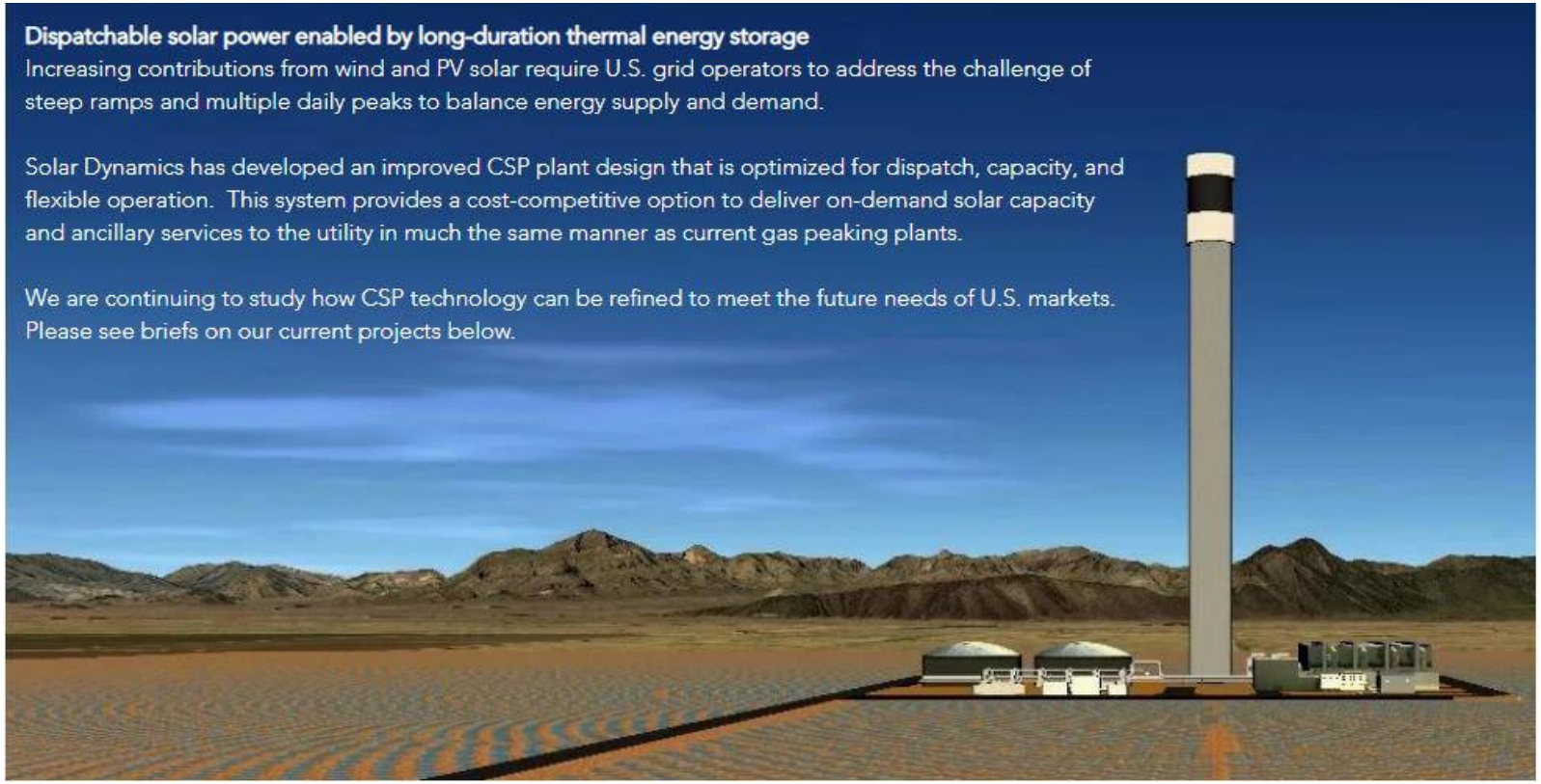
Technology Type: Concentrated Solar Power molten-salt tower with thermal energy storage

Description: 90-180 MW, depending on configuration

Project development status: operations expected to begin in 2028; concentrated solar power utilizing molten salt thermal storage is a commercially available technology

Details:

- 12-16 hours of energy storage possible
- No cycling limits



Source: Solar Dynamics, LLC (https://www.solardynllc.com/csp-plant-technologies)

RENESOLA POWER HOLDINGS, LLC

Technology Type: Photovoltaic solar energy-based electricity generating facility

Description: utility-scale generating capability from solar array and battery storage

Project development status: development ongoing

Details:

- Solar energy used in part to charge batteries with remainder delivered to grid
- Expected COD prior to targeted RFI timeframe



ReneSolar selected US projects
Source: www.renesolapower.com

RPLUS HYDRO, LLC/RPLUS ENERGIES, LLC

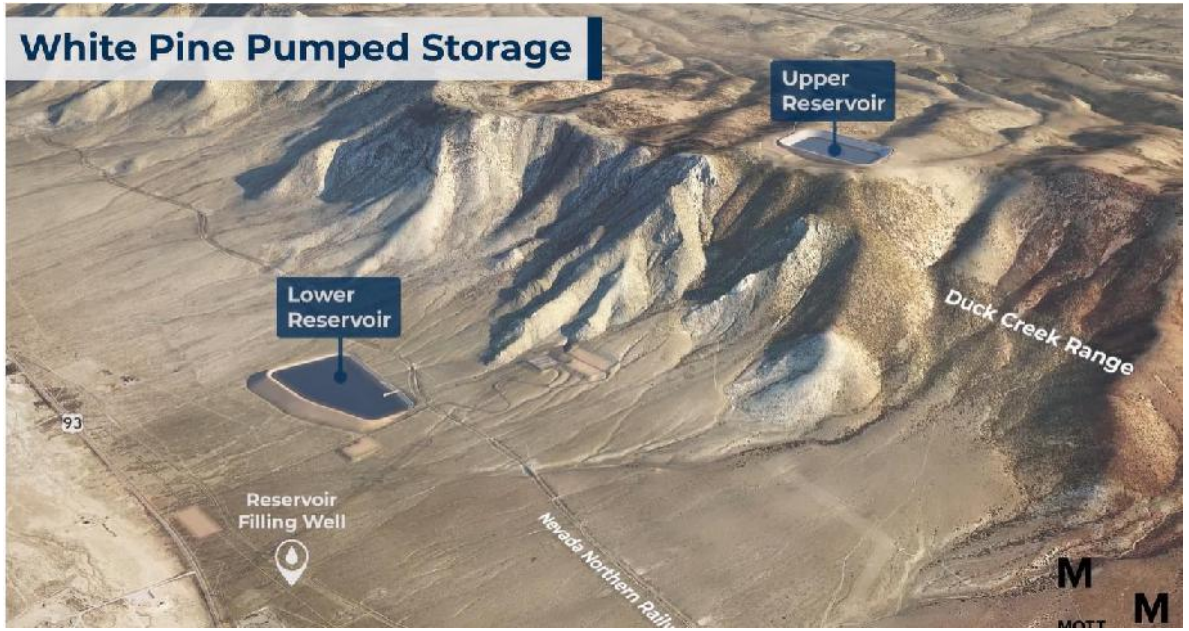
Technology Type: Pumped Hydroelectric Energy Storage

Description: A 600 MW closed-loop pumped hydroelectric storage facility

Project development: expected commissioning in 2030

Details:

- Located in San Juan County, NM
- Well-known and widely used technology



White Pine Pumped Storage project near Ely, Nevada (project still in development)
Source: RplusHydro (https://www.whitepinepumpedstorage.com/)

UPLIGHT INC

Technology Type: Software solutions/platform designed to achieve greater load flexibility

Description: Provides DR, energy efficiency, and active TOU rate management, and includes tools for both residential demand and EV load shifting

Project development status: actively deployed technology

Benefits:

- Greater load flexibility and DER management
- Programs can be simple or complex; programs are stackable



Source: Uplight Inc.
(https://uplight.com/solutions/digital-customer-activation/)
(https://uplight.com/solutions/electric-vehicle-adoption-and-experience/)

WALLIS ENERGY CORPORATION

Technology Type: Pumped Hydroelectric Energy Storage

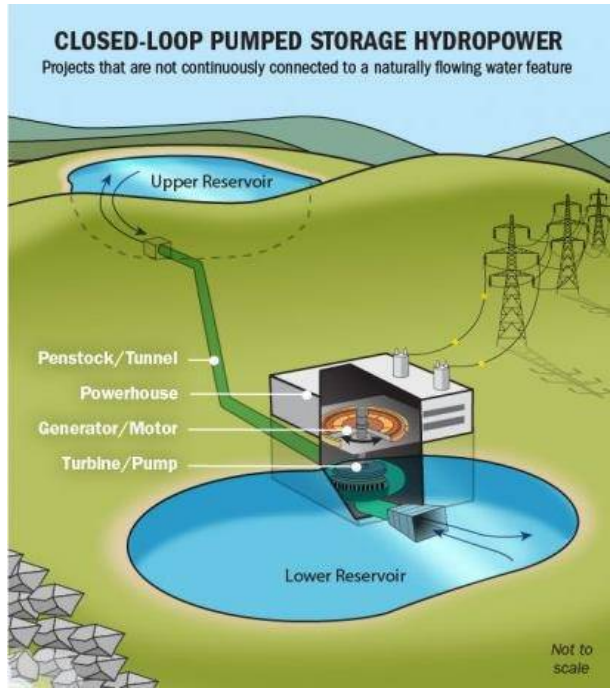
Description: A 600 MW project with 12+ hours of duration

Project development status: project currently in early development with earliest COD in 2028; well-known and widely used technology

Details:

- Located in Arizona and New Mexico on tribal land (Navajo Nation)
- POI at Shiprock, San Jose or Four Corners
- For 12-hour duration: 100 acres needed (increases with storage duration)
- At least one reservoir will be covered to reduce evaporation
- RTE of 80%

WALLIS ENERGY, INC.
Oil & Gas Exploration & Production



Source: www.energy.gov

RFI RESPONSES – EMERGING TECHNOLOGIES

10 Emerging Technologies from 10 developers

- Coyote Clean Power
- CSOL
- EDF Renewables
- Escalante H2 Power LLC
- Form Energy
- Mainspring
- Morse Associates, Inc.
- Motor EV LLC
- NextEra 360
- Wallis Energy Corp

Technology Types

- EV subscription service
- Hydrogen as fuel
- Geothermal steam service
- Green hydrogen as energy storage/fuel
- Iron air storage
- Linear generator
- Operations software
- Thermal generation with carbon capture

AEQUATIS ENERGY SOLUTIONS

Technology: H2 Storage Project

Technology Type: Fuel

Description: create hydrogen using excess renewable energy

Readiness: unclear

Details:

- Minimal information provided

PNM Talk to us. PNM.com

COYOTE CLEAN POWER

Technology: NET Power Plant

Technology Type: Thermal Resource

Description: 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).

Technology readiness: proven at small scale

Benefits:

- Provides firm, dispatchable capacity and energy
- Uses proprietary Allam-Fetvedt process that recycles CO2 as a working fluid and captures excess as pipeline- quality CO2
- Brownfield site on Southern Ute Indian Reservation using pre-existing mothballed equipment
- No NOx, SOx, VOC or particulate emissions
- Water-neutral

NETPOWER



NET Power Facility Operating in La Porte Texas
Source: www.netpower.com

EDF RENEWABLE

Technology: Hydrogen Production

Technology Type: Fuel

Description: Green H2 production for PNM's fossil fired generating stations

Technology Readiness:

Benefits:

- May decrease the need for large scale storage
- Will aid PNM in meeting carbon free goal while reducing the need for new transmission



Luna Energy Facility

ESCALANTE H2 POWER LLC

Technology: Hydrogen fueled power production

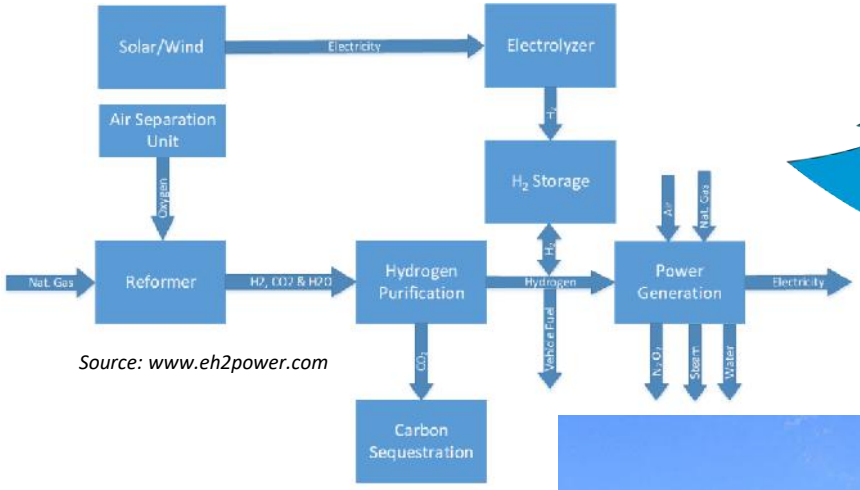
Technology Type: Fuel

Description: Proposes retrofit of Escalante Generating Station to use blue/green hydrogen

Technology Readiness: blue hydrogen commercial

Benefits:

- Utilizes carbon-capture technology for blue hydrogen production; uses renewables to produce green hydrogen
- Repurposes existing fossil fired generator
- Supports local economies – sited in Prewitt, NM
- Can use both natural gas or H2 as fuel



Source: www.eh2power.com



Escalante Generating Station *Source: www.gallupedc.com*

FORM ENERGY

Technology: Steady State Iron-Air Storage

Technology Type: Energy Storage

Description: energy storage using reversible rusting process

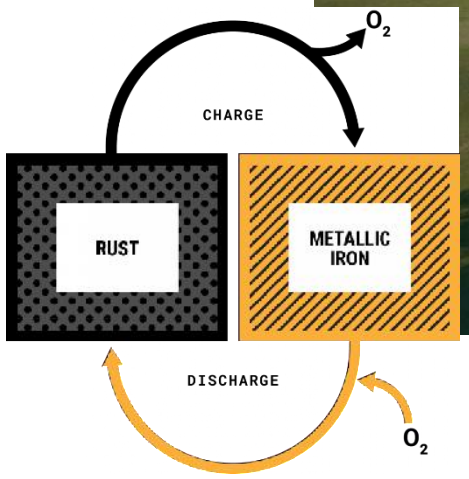
- When discharging, battery cycle breathes in oxygen from air to convert iron metal to rust
- When charging, the process is reserved when an electrical current converts the rust back to iron

Technology readiness: commercialized at small scale, large scale unproven

Benefits:

- Firms renewable resources and reduces curtailment
- Modular, scalable, reliable and clean
- Long duration storage
- Complimentary to lithium-ion battery storage





Source: www.formenergy.com

PLUS POWER, LLC

Technology Type: Steady-state Iron-air Energy Storage

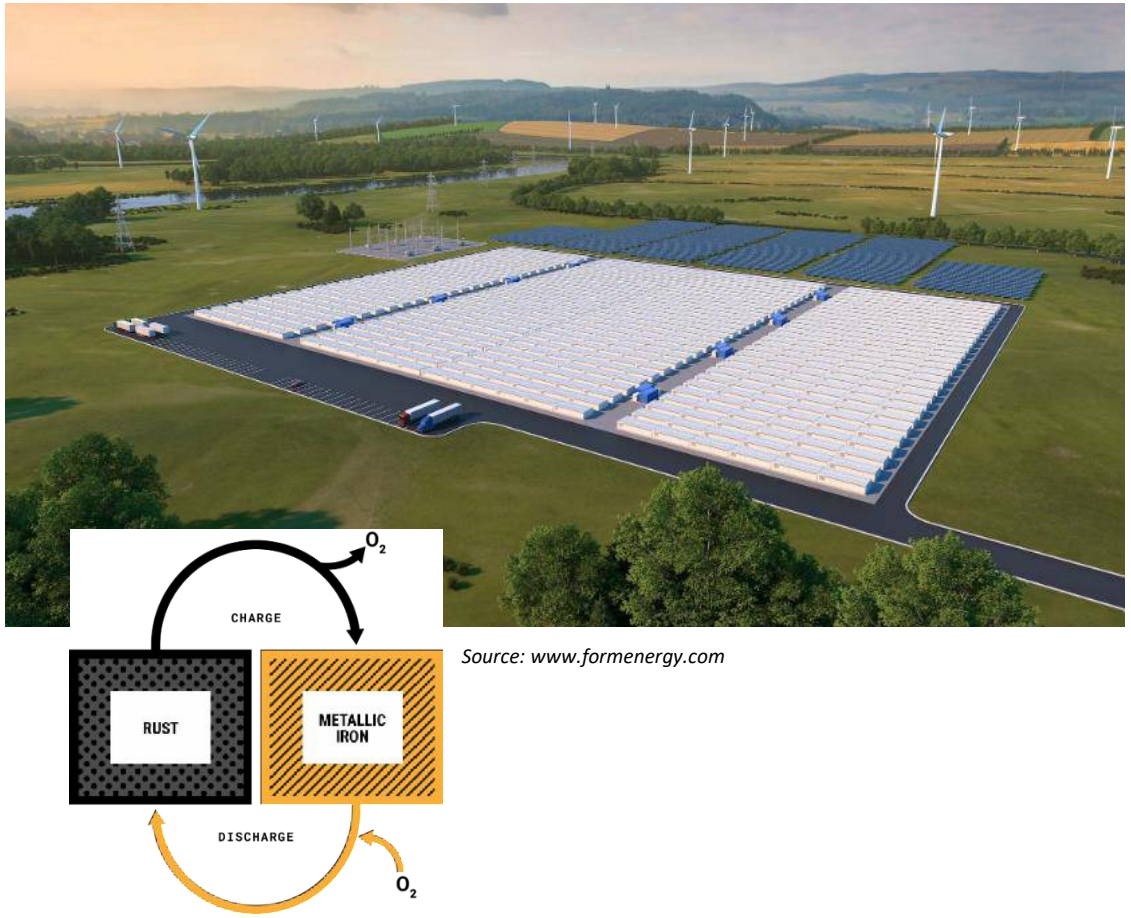
Description: energy storage using reversible rusting process

- When discharging, battery cycle breathes in oxygen from air to convert iron metal to rust
- When charging, the process is reserved when an electrical current converts the rust back to iron

Project development status: small scale proven

Details:

- Uses equipment/technology delivered by Form Energy
- Modular and scalable
- Can reduce renewable generation curtailment and firm variable renewable generation over days (100 hours of storage capability)



Source: www.formenergy.com

Talk to us.

MAINSPRING ENERGY

Technology Name: Linear Generator Units

Technology Type: Thermal Resource

Description: Generator units that uses low temperature reaction of air and fuel to drive magnets through copper coils to efficiently produce energy

Technology readiness: commercialized at small scale, no large-scale installations at this point

Benefits:

- Near zero NOx emissions
- Fully dispatchable
- Fuel flexibility: allows seamless witch between natural gas, biogas, hydrogen & other fuels
- Modular – installed in 250 kW increments
- Majority of equipment can be repurposed at end of life
- Can be used to firm renewable energy similar to battery storage
- Can provide ancillary services
- Suitable to local applications reducing the need for transmission





Source: www.mainspringenergy.com

MOTOR EV LLC

Technology Name: Motor Drive/Motor Up Program

Technology Type: Service

Description: Consumer electric vehicle adoption platform designed to improve EV adoption rates; can implement utility-preferred EV rate or managed charging programs

Technology readiness: commercially available; AES Indiana has partnered with Motor

Program Details:



Motor Drive: bundled EV subscription service, with a low-commitment flat monthly fee includes:

- Electric Vehicle (priced by tier)
- Insurance, maintenance, and registration
- Roadside assistance and concierge services
- In-home Level 2 charger and installation (additional costs may apply)
- In addition to the vehicles, Motor handles all administrative components

Motor Up: digital EV purchase platform with bundled EV services

- Digital purchase experience, option to bundle additional services such as home charger installation and EV program enrollment to reduce the complexity of the EV purchase process
- Enables utility customers the ability to browse and purchase EV inventory available at Motor's local partner dealers

NEXTERA 360

Technology: NextEra 360 Software

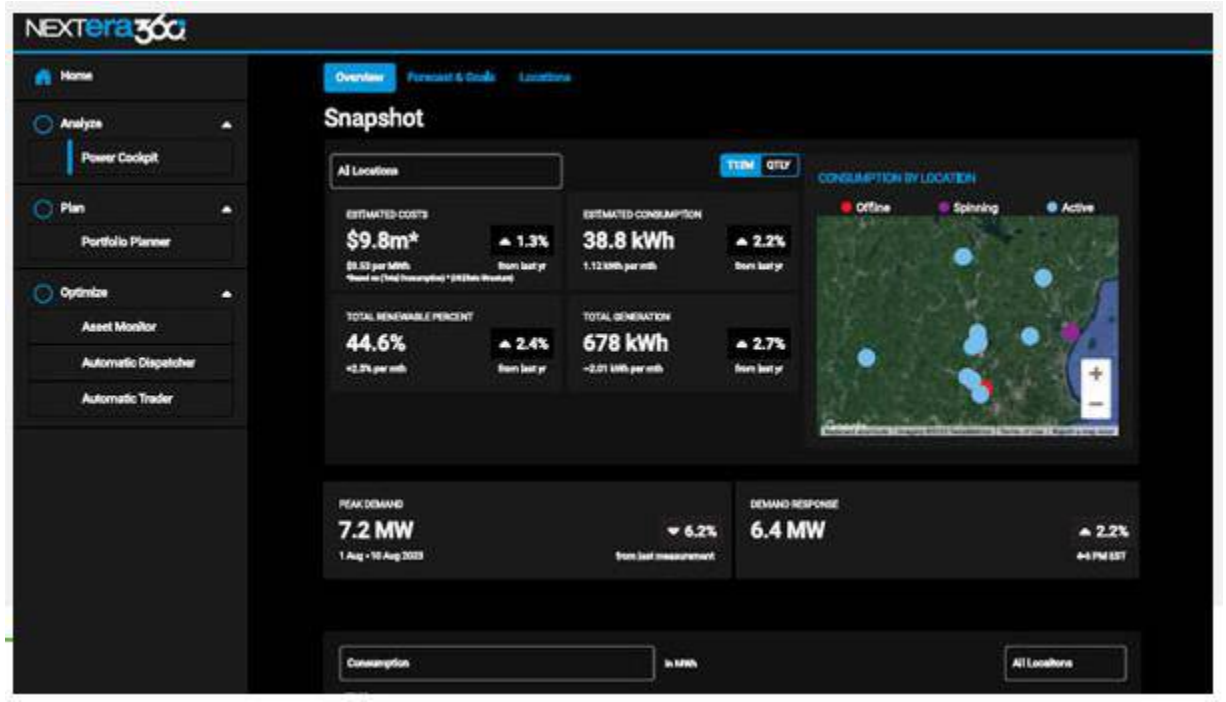
Technology Type: Service

Description: software designed to forecast and model market conditions, predict and optimize asset performance to make utility operations more efficient

Technology readiness: implemented

Software details:

- Helps a utility analyze, plan, optimize solutions for decarbonization goals
- Can track/forecast energy, carbon emissions for sustainability goals, optimize asset performance, automate dispatch strategies



Source: https://www.nexteraenergyresources.com/nextera360/solutions.html

WALLIS ENERGY CORPORATION

Technology: Geothermal steam service

Technology Type: Fuel

Description: uses new drilling techniques to provide steam for use in:

a) existing coal or other steam electric plants or

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

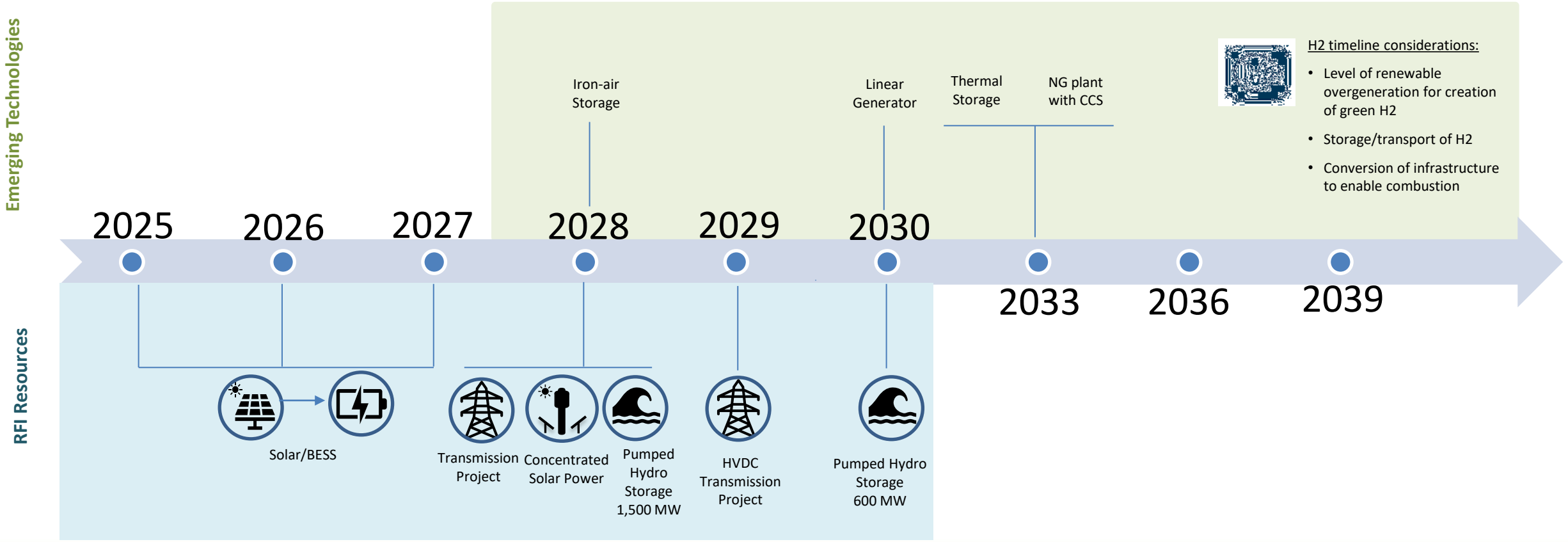
Technology readiness: developer reports TRL 6-7

Benefits:

- Will reduce waste streams through use of naturally occurring geothermal energy
- Closed loop system
- Repurposes existing fossil fuel generating stations

RFI RESPONSES SUMMARY: RESOURCES FOR 2028-2033

TIMELINE FOR POTENTIAL OPERATION



SUMMARY

DUE DILIGENCE ON RFI RESPONSES IS ONGOING

- We don’t yet have a conclusion about which technologies will be modeled and how they best fit in to the IRP analysis framework and timeline
- We are still analyzing responses, reaching out to developers for more information, and obtaining input from PNM Generation and Transmission teams and industry experts
- Through these efforts and our ongoing analysis, we aim to build a better understanding of:
    - Timeline for potential operation of these resources
    - More about feasibility/evolution of emerging technologies
    - Transmission implications
- To the extent that responses from earlier RFIs might inform the 2023 IRP analysis, we will evaluate those as well
- Results of our RFI response analysis will be presented to the Stakeholder group – please stay tuned for updates on this

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: November 2, 2022

Topic: Public Advisory Steering Meeting #8: Commodity & Pricing Forecasts

Start Time: 9:00 AM

Location: Virtual

PNM will continue to hold virtual meetings. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: November 16, 2022

Topic: Public Advisory Steering Meeting #9: Modeling Input #3: Load Forecasting, PV DG Forecast, EE Bundles & PNM Existing System

Start Time: 9:00 AM

Location: Virtual

PNM will continue to hold virtual meetings. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by October 28, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Commodity & Pricing Forecasts

STEERING MEETING #8

NOVEMBER 2, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

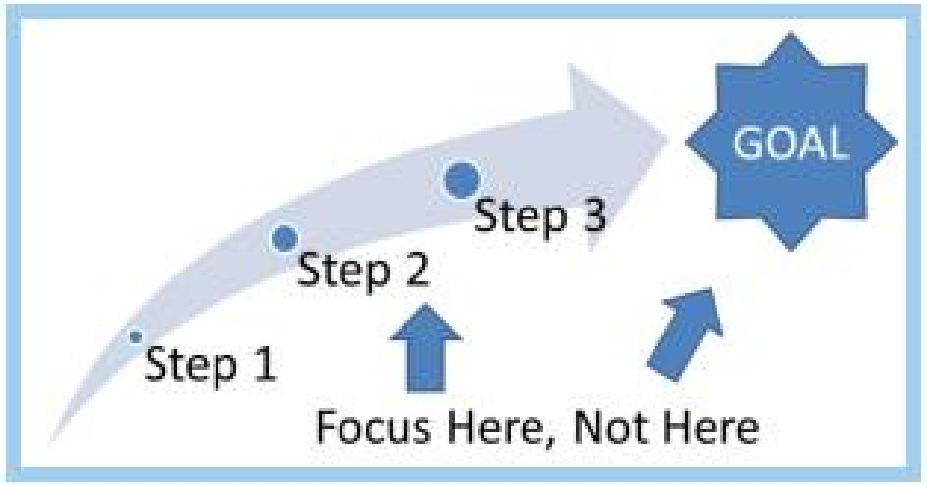
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

- Welcome and Introductions
- Siemens forecasts
  - Natural Gas & CO_2
  - Capital Costs
- IRP application of Siemens forecast
- Scenario Process
- Next Steps

Price Outlook: Natural Gas, CO_2, Capital Costs

Public Service New Mexico
November 2022

© Siemens 2022

SIEMENS

Contents



- Introduction
- Tools and Methodology
- Base Case Scenario Assumptions and Forecasts
- High and Low Scenario Assumptions and Forecasts

© Siemens 2022

Introduction

- Siemens PTI developed market assumptions for PNM in July 2022
- Market forecast of natural gas, carbon emission price, and capital costs were developed to assist PNM with its 2023 Integrated Resource Plan
- The forecast for each of these commodities was developed based on input from subject matter experts, research, internal analysis, and propriety data over the 2022-2043 planning period

Scenario	Description
Baseline	Reference view based on market forwards early and longer term by fundamentals accounting for expected policy
High	High prices reflect increasing social costs for CO_2 and higher price of natural gas based on statistical analysis
Low	Low prices reflect no costs for CO_2 and lower price of natural gas based on lower band of statistical analysis

- This presentation summarizes the methodology utilized as well as assumptions used to derive the price forecast

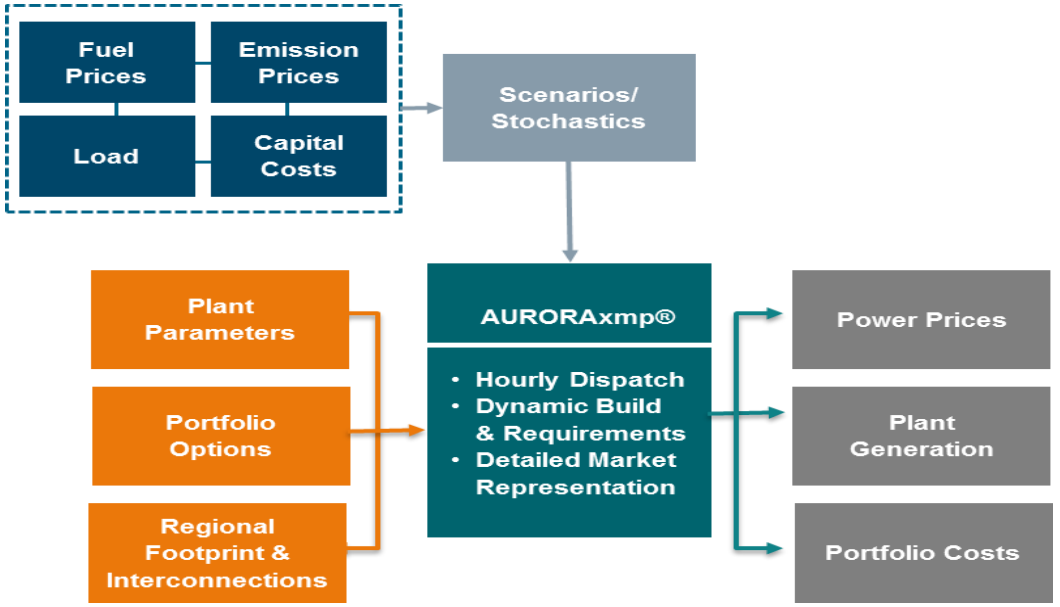
© Siemens 2022

Tools and Methodology

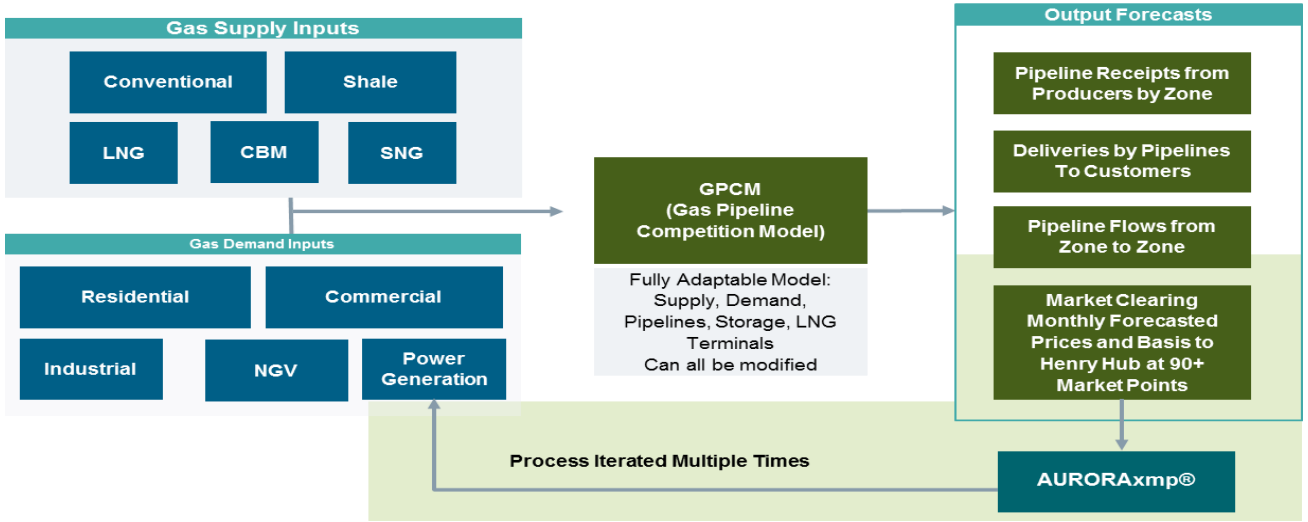
SIEMENS

Gas and Power Integrated Modeling Approach

AURORAxmp® as a Modeling Framework



GPCM Modeling Framework



- Power modeling used AURORAxmp®, an hourly dispatch model, to simulate the economic dispatch of power plants within WECC power markets for the forecast horizon. AURORAxmp® assesses the economics of existing and future generation technologies for future builds and retirements in order to maintain minimum reserve margins and meet RPS and carbon free generation targets.
- Natural gas price inputs are produced using GPCM, a dynamic model that incorporates natural gas supply, demand, and infrastructure inputs to solve for expected prices and flows throughout North America.
- Iterations are performed between the two models to ensure gas prices and power sector natural gas demand is in balance.

© Siemens 2022

SIEMENS

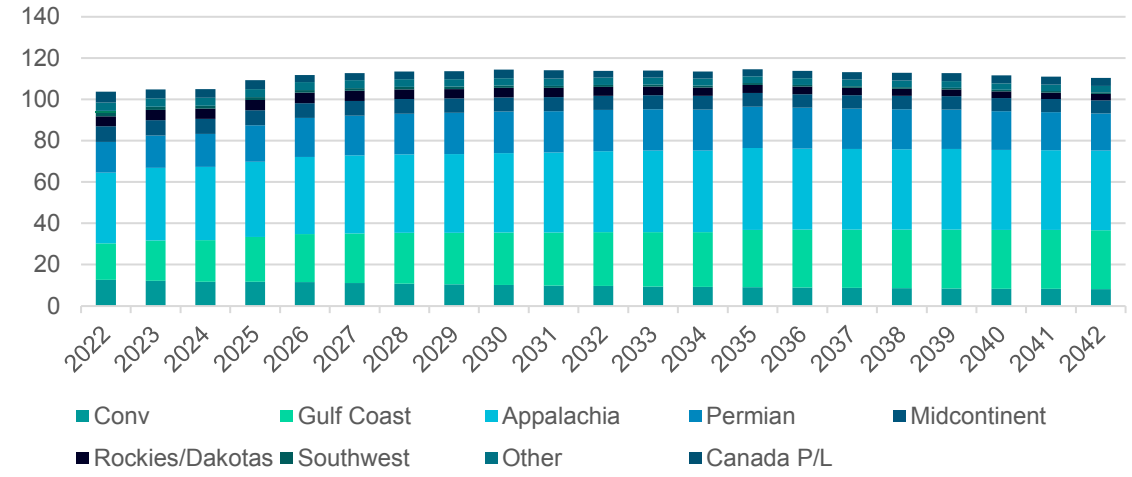
Natural Gas Forecast

SIEMENS

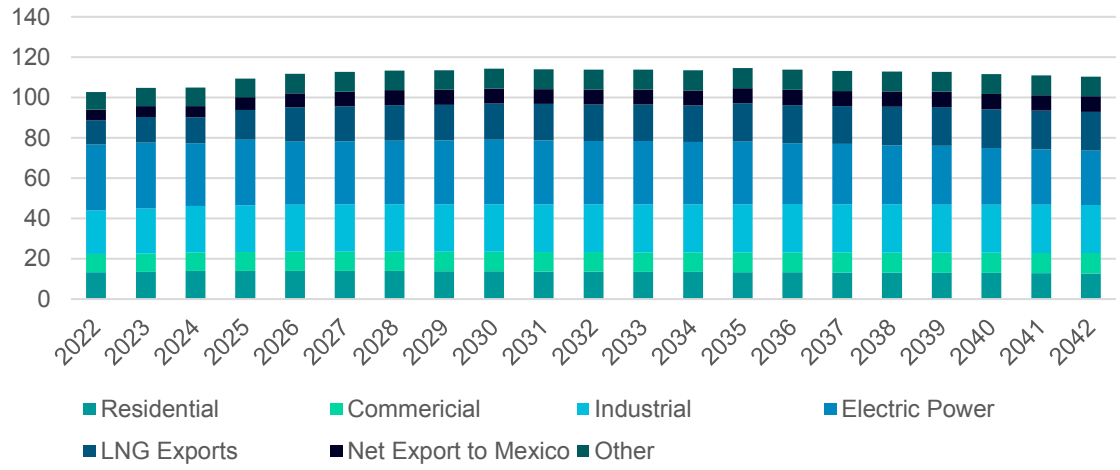
Key U.S. Gas Market Drivers

All units in BCF/D

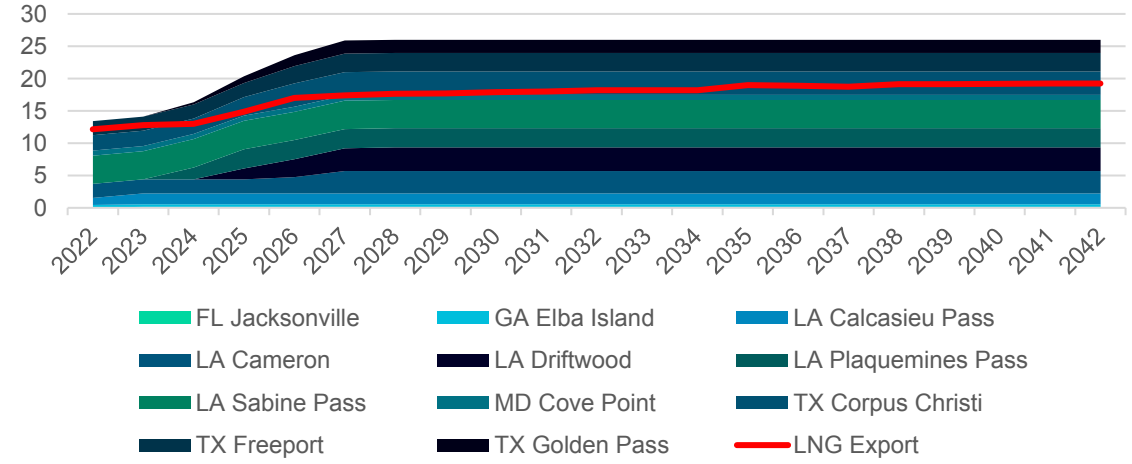
U.S. (L48) Gas Supply Outlook



U.S. Gas Demand Outlook



U.S. LNG Export Capacity and Export Outlook



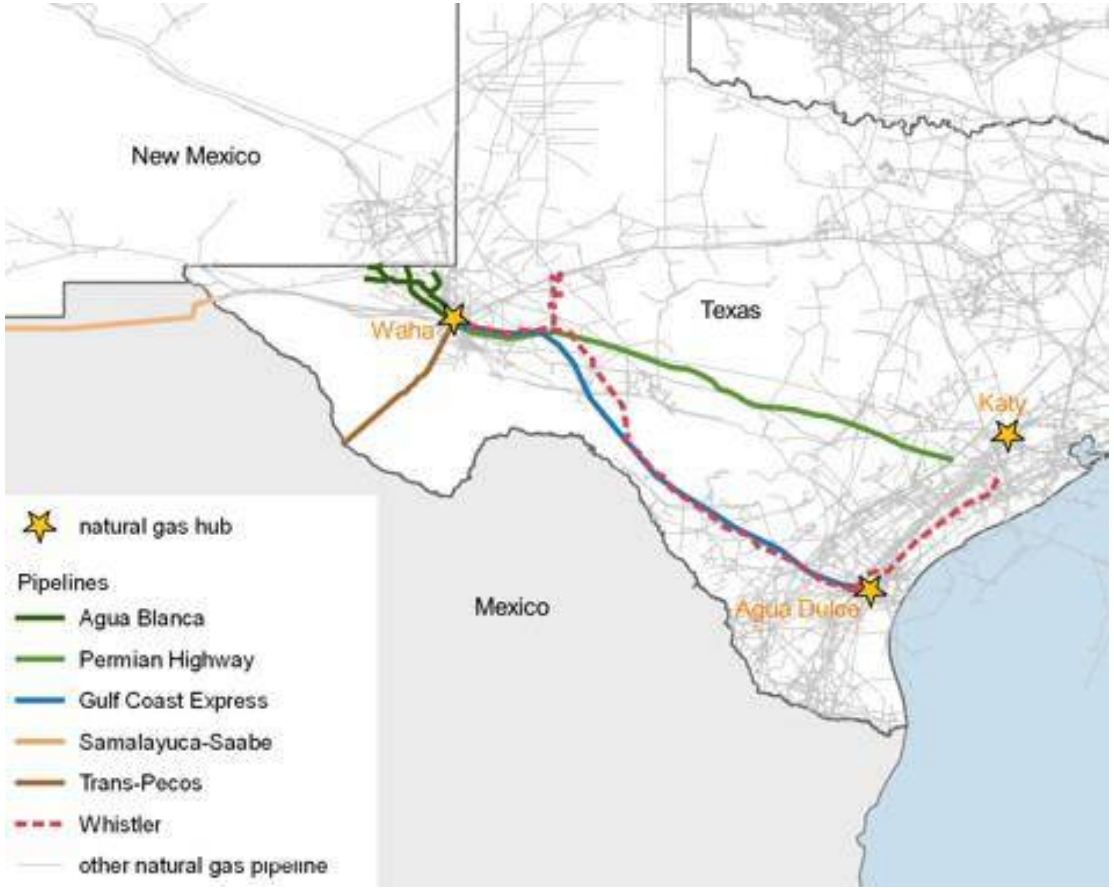
Key Insights

- Gas supply increasing post-COVID era driven by higher prices and increasing demand
- Natural gas use in electric power generation, over the long term expected to decline due to increasing renewable portfolio standards
- LNG exports have increased dramatically to supply primarily European and Asian markets and are expected to grow with increasing investment in export capacity
- Mexico pipeline export also increasing due to greater demand and infrastructure buildout

© Siemens 2022

SIEMENS

Several Pipelines have been built to delivery Permian Gas from Waha Hub to South Texas and Beyond



Source: EIA

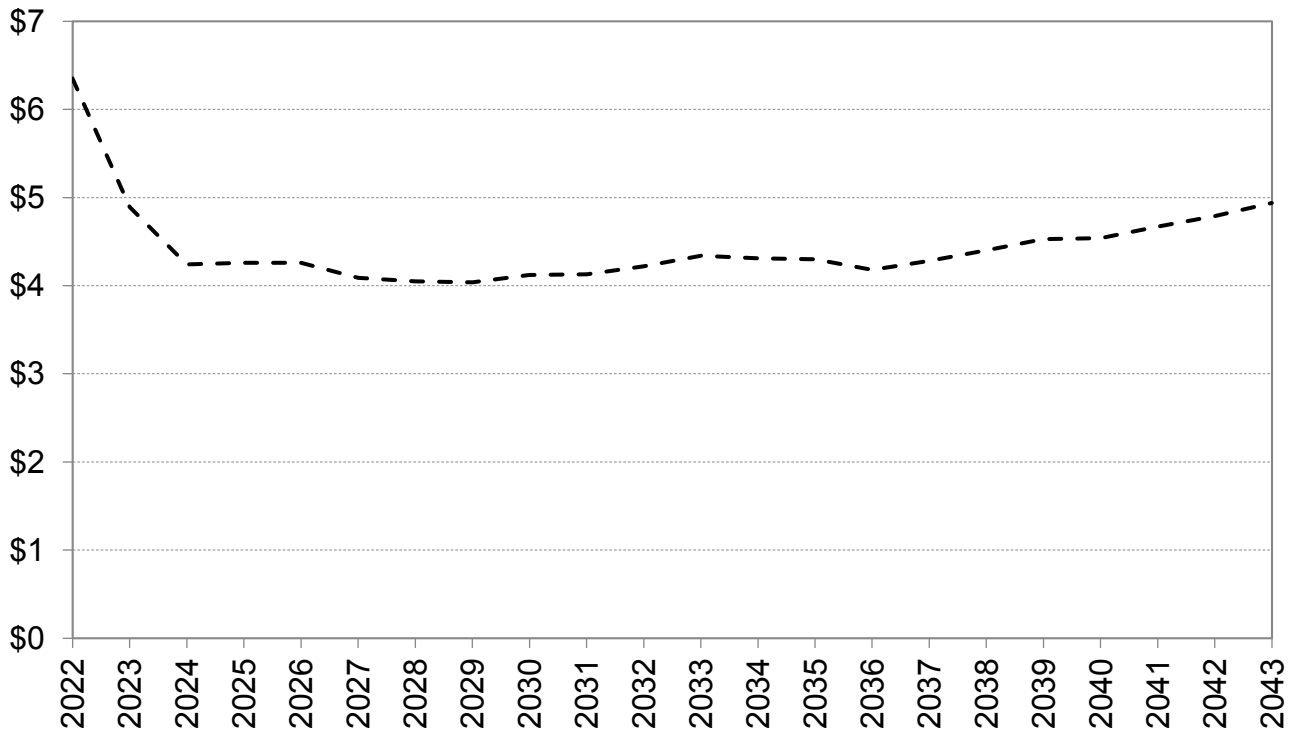
- Permian gas production is expected to increase from ~15 Bcf/d in 2022 to ~20 Bcf/d by 2030
- Gas pipeline takeaway capacity is expected to reach ~17 Bcf/d by YE2023
- Expansion projects being developed to increase takeaway capacity

© Siemens 2022

SIEMENS

Baseline Natural Gas Prices – Henry Hub (HH)

Baseline HH Natural Gas Price Forecast (2021$/MMBtu)



*Base case prices were developed using NYMEX forwards for Henry Hub for the first 18 months starting July 2022, Mix of forward and fundamentals for next 18 months; fundamentals March 2025 onwards

Henry Hub

Near-Term – Reflects historical data and market forwards through September 2023. The next 18 months is a blend of forwards and fundamental through February 2025

- Oil and gas prices are high enough to boost economic production
- Rig deployment sluggish due to capital discipline and hedging programs that have kept producers from fully realizing high prices
- LNG export utilization all-time high due to European demand

Mid-Term – HH prices are expected to moderate as supply increases to meet increasing demand from LNG. Supply growth coming from Permian, Marcellus, Haynesville, Eagle Ford and Utica shales

Long-Term – Post 2035, natural gas prices projected to rise due to higher costs of production, despite lower levels of demand from power generation and relatively flat demand in CR&I sectors

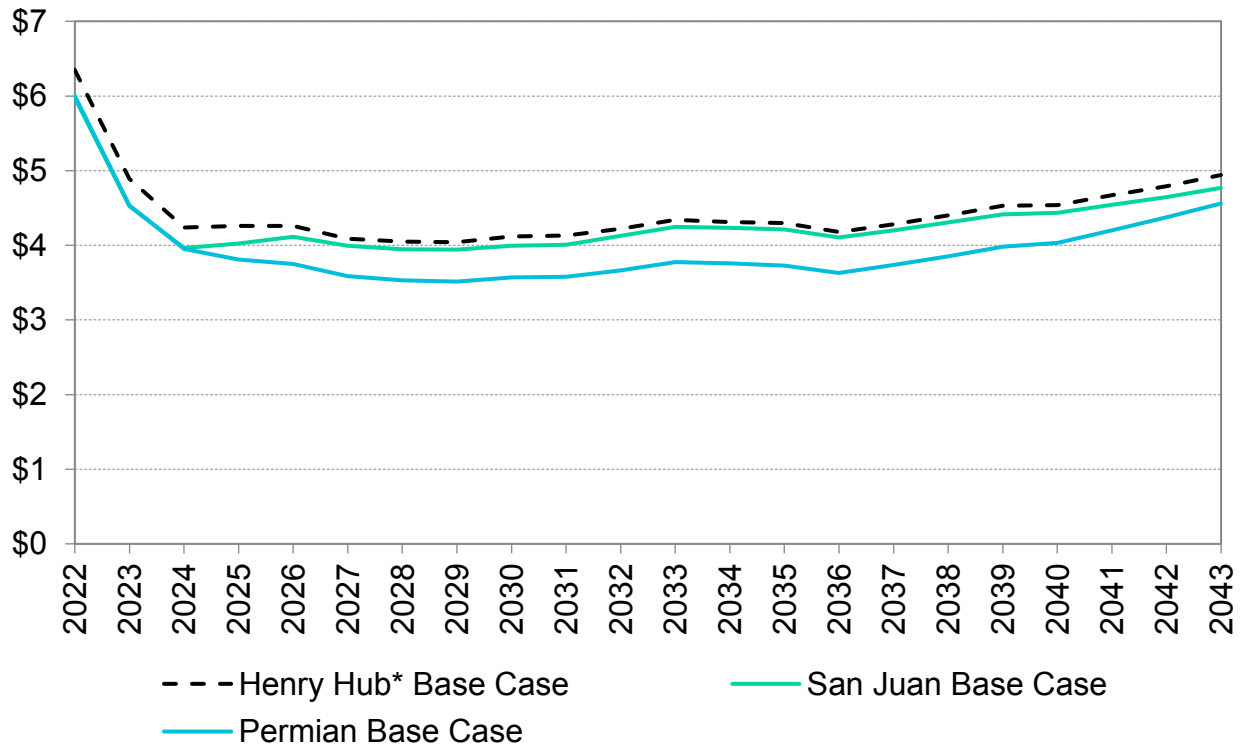
- Power generation gas consumption will reduce due to rising renewable generation to meet RPS standards
- Decrease in residential demand is offset by an increase in commercial and industrial sectors

© Siemens 2022

SIEMENS

Baseline Natural Gas Prices – Permian and San Juan

Baseline Regional Natural Gas Price Forecasts, $2021/MMBtu



*Base case prices were developed using NYMEX forwards for Henry Hub for the first 18 months starting July 2022, mix of forward and fundamentals for next 18 months; fundamentals March 2025 onwards

Permian

- Permian production is robust and continues to grow even with very low HH prices
- Near term, Permian prices are expected to have a negative basis of ~0.35 $/MMBtu to HH
- Longer term, basis to HH is expected to widen to an average of ~-0.50$/MMBtu. To keep up with increasing demand, particularly from LNG, production is expected to increase
- Pipelines/expansion in the future may put some upward pressure on prices and could reduce the basis differential to HH over the planning horizon

San Juan

- Production region in northwest NM into southern CO
- CBM and Conventional production of gas continues to decline and is expected decline and remain a secondary source of gas for the Southwest

© Siemens 2022

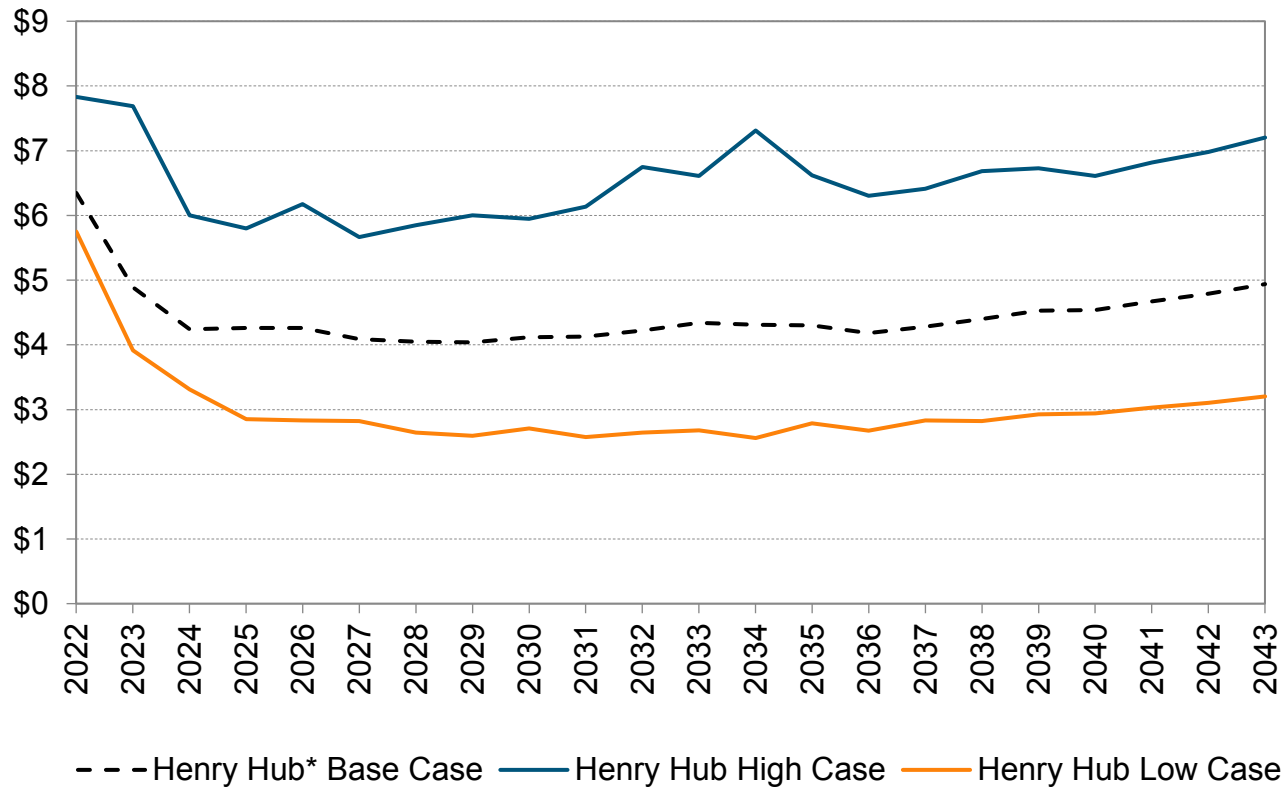
SIEMENS

High and Low Cases

SIEMENS

Natural Gas Price Scenarios – Henry Hub

HH Natural Gas Price Scenarios, $2021/MMBtu



*Base case prices were developed using NYMEX forwards for Henry Hub for the first 18 months starting July 2022, mix of forward and fundamentals for next 18 months; fundamentals March 2025 onwards

Henry Hub Low and High Cases

Low Case –Reflects an outlook based on a statistical analysis of historical at the 10% confidence internal. Prices settle around $3/MMBtu longer term

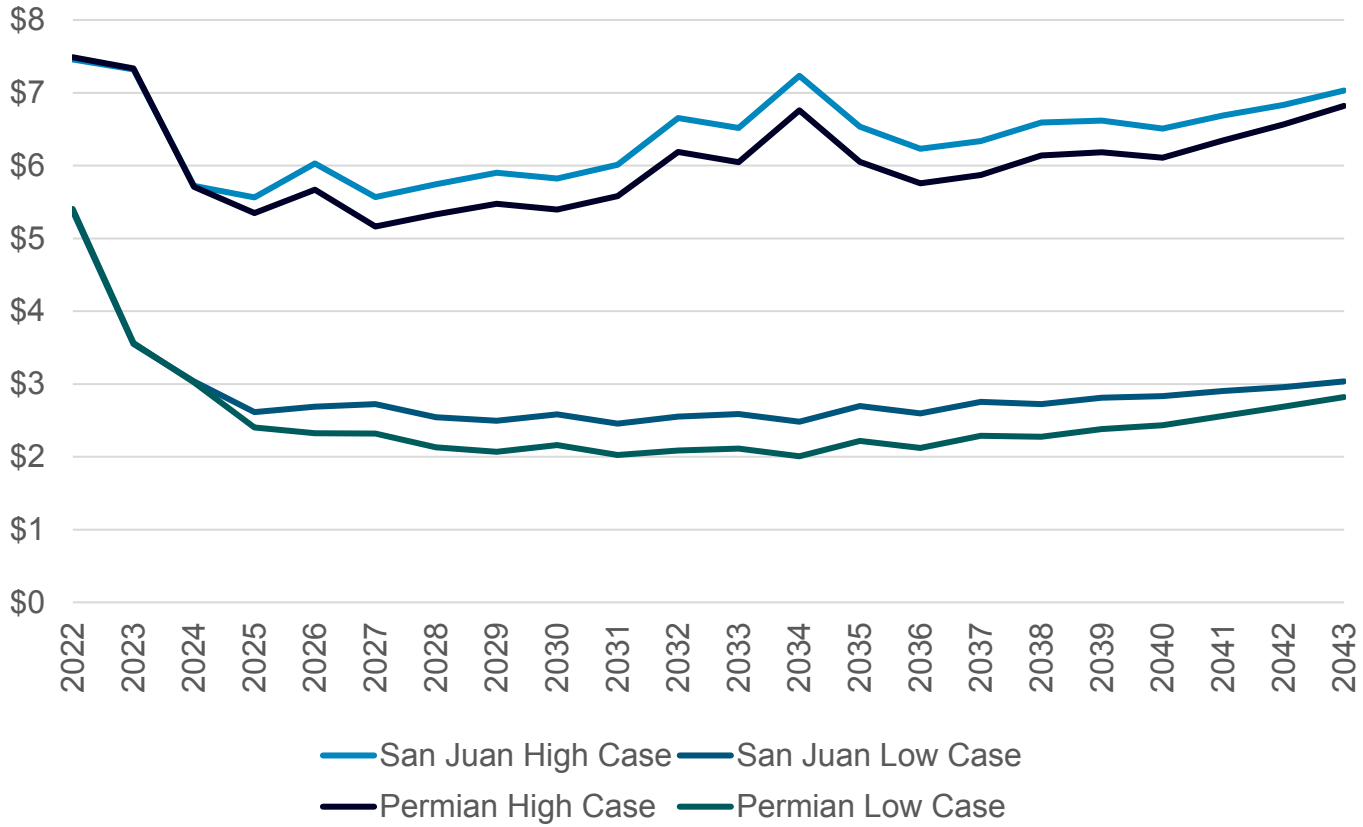
High Case – Reflects an outlook based on Statistical analysis of historical at 90% confidence interval. Prices increase above ~$6/MMBtu longer term

© Siemens 2022

SIEMENS

Natural Gas Price Scenarios – Permian and San Juan

Permian and San Juan Natural Gas Price Scenarios, $2021/MMBtu



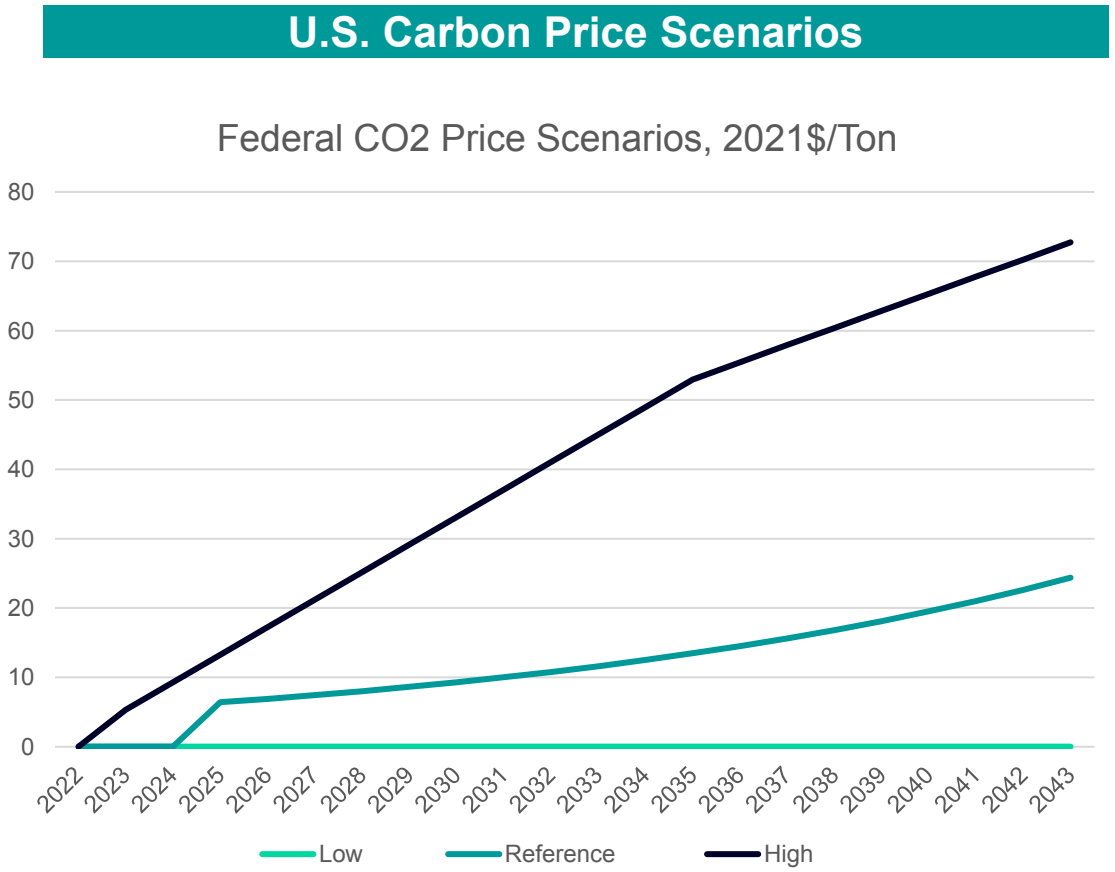
- Permian and San Juan price outlook consistent with HH High and Low scenario and basis differential consistent with baseline scenario
- Low case prices above $2/MMBtu longer term
- High case prices ~$6-$7/MMBtu longer term

© Siemens 2022

SIEMENS

Carbon Price Scenarios – Federal

- Range of federal carbon prices reflects uncertain outlook for carbon policy and resulting pricing in western states
- Baseline scenario assumes a carbon policy starting in 2025 to achieve 80% reduction in carbon emission in the power sector relative to 2005 levels
- High scenario nears $70/ton by the end of the forecast horizon and incorporates social cost of carbon emission
- Low case represents no cost for carbon emission



© Siemens 2022

SIEMENS

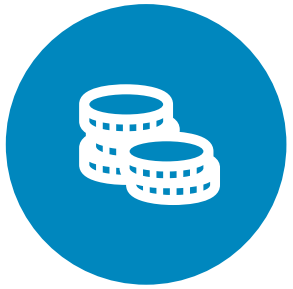
Capital Cost Forecast



Overnight capital cost forecast for various technologies developed based on numerous sources



Regional factors developed for each technology to account for difference in locality and ambient conditions. Regional factors are based on EIA Annual Energy Outlook



Near term capital cost reflect increasing cost of commodities, supply chain challenges and other economic factors

Incorporates tax credits from Inflation Reduction Act 2022

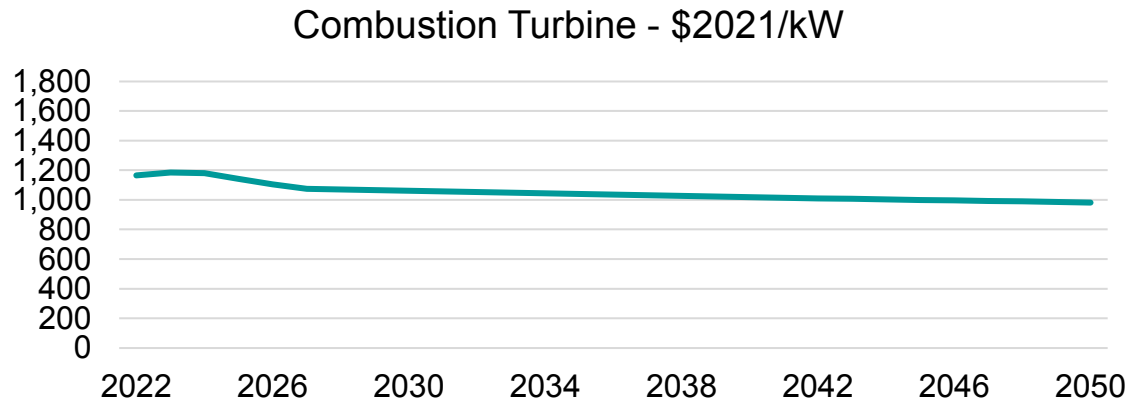


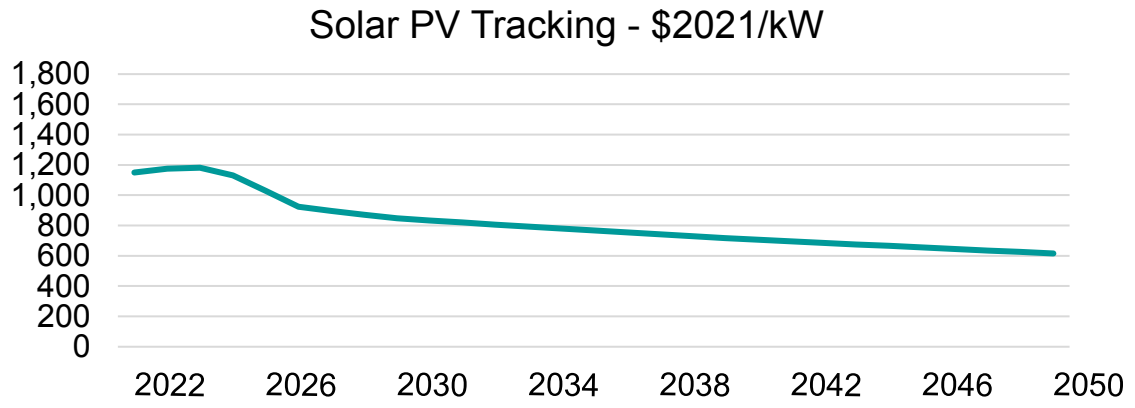
Longer term capital costs expected to decline in real terms due improvement in technology

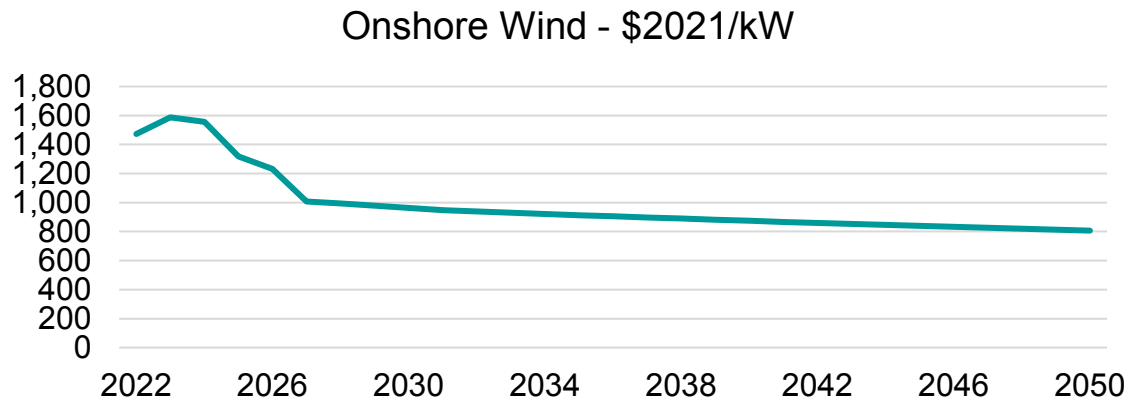
© Siemens 2022

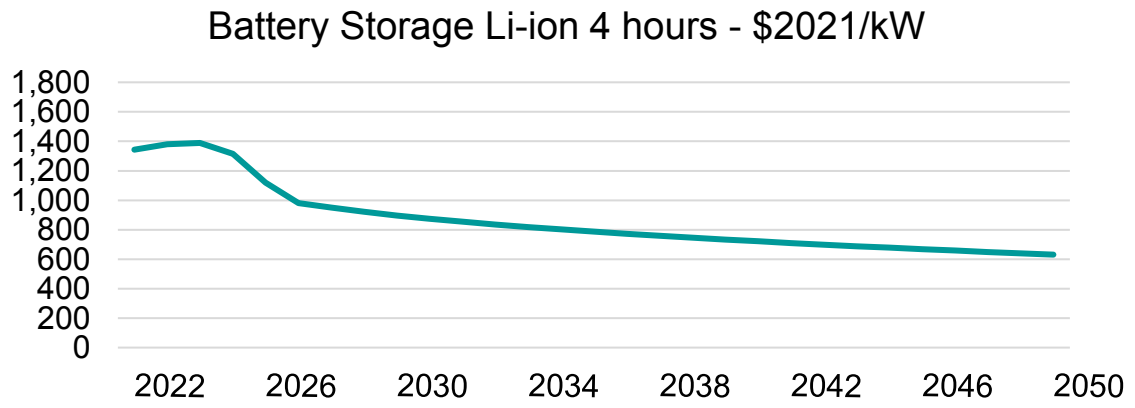
Capital cost forecast for select technologies incorporates regional factors to build in New Mexico

**Costs outlook does not reflect incentives provided by the Inflation Reduction Act 2022*









© Siemens 2022

SIEMENS

© Siemens 2022

Contact



Anuj Patel
Principal
Mobile: (281) 939-2144
Email: Anuj@siemens.com



Holt Bradshaw
Principal

Email: Holt.Bradshaw@siemens.com

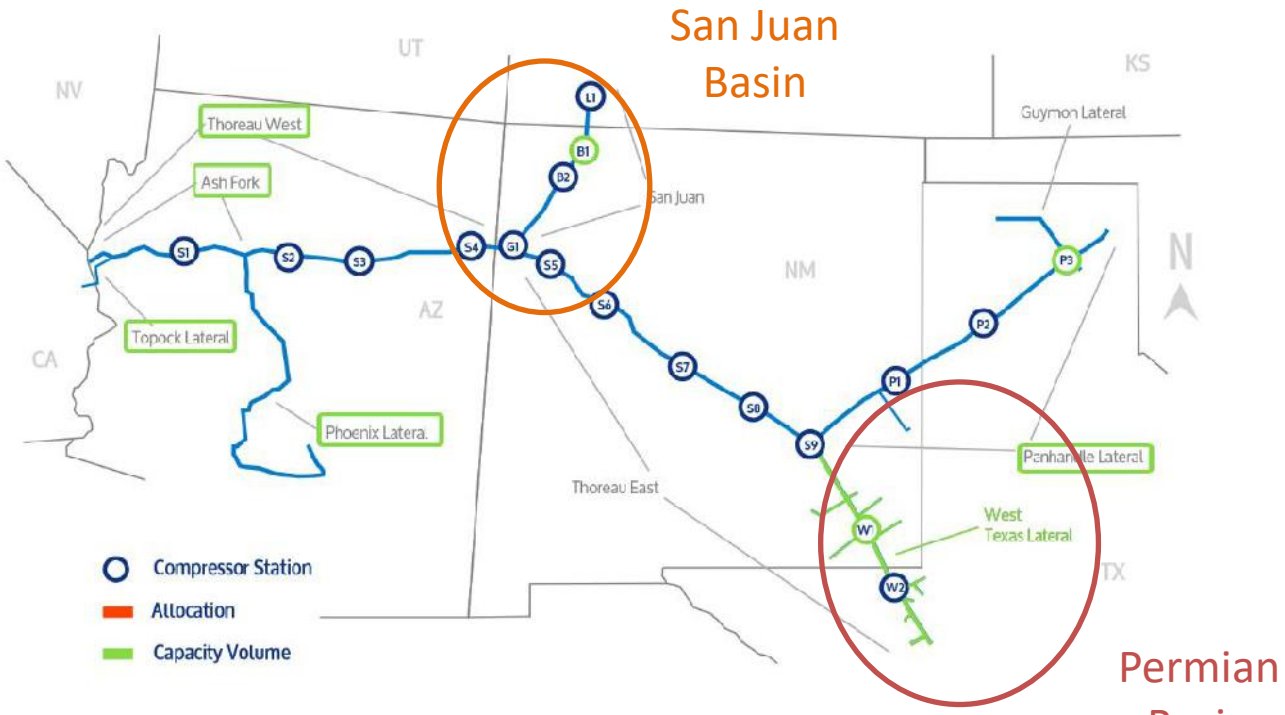


Angelina Martinez
Project Director

Email: Angelina.Martinez@siemens.com

2023 IRP APPLICATION OF SIEMENS FORECASTS

DELIVERED NATURAL GAS PRICES USED IN THE 2023 IRP



Source: Transwestern Pipeline Company, twtransfer.energytransfer.com

Basin Pricing (Siemens Forecast)

2 Pricing Hubs

Transportation Charges, Usage Charges, Taxes

4 Pricing locations

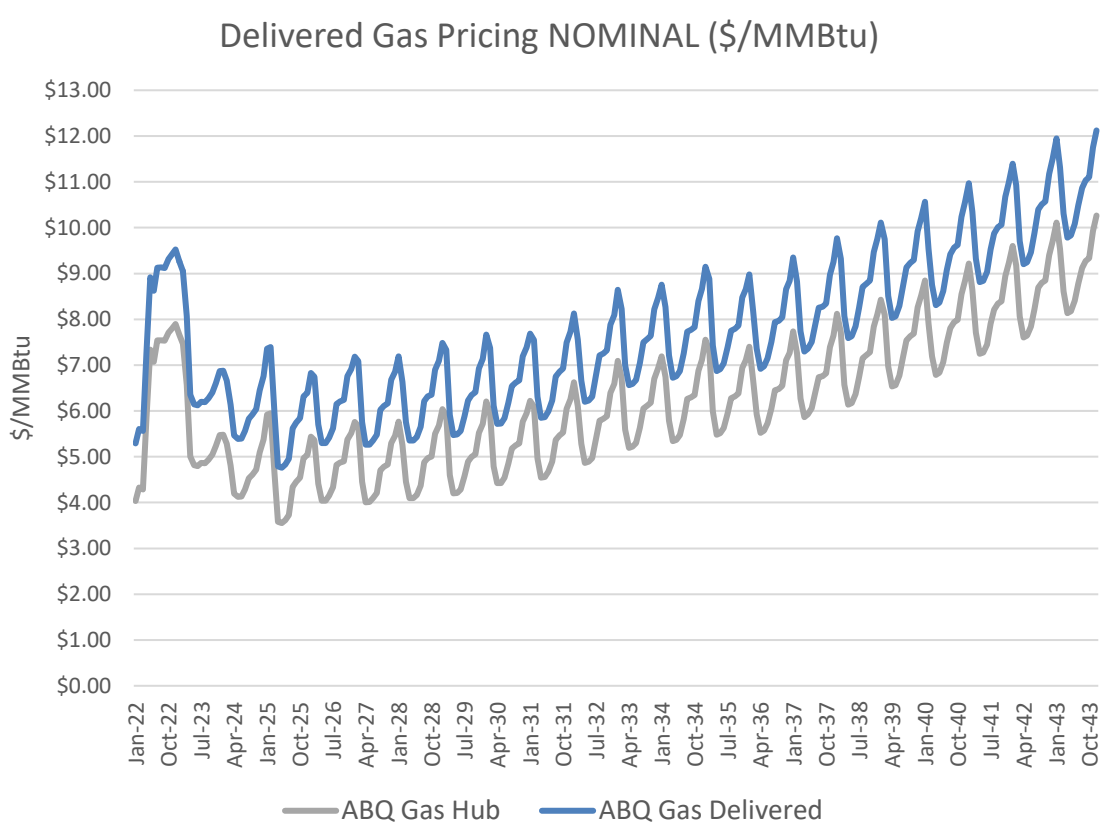
Delivered Price

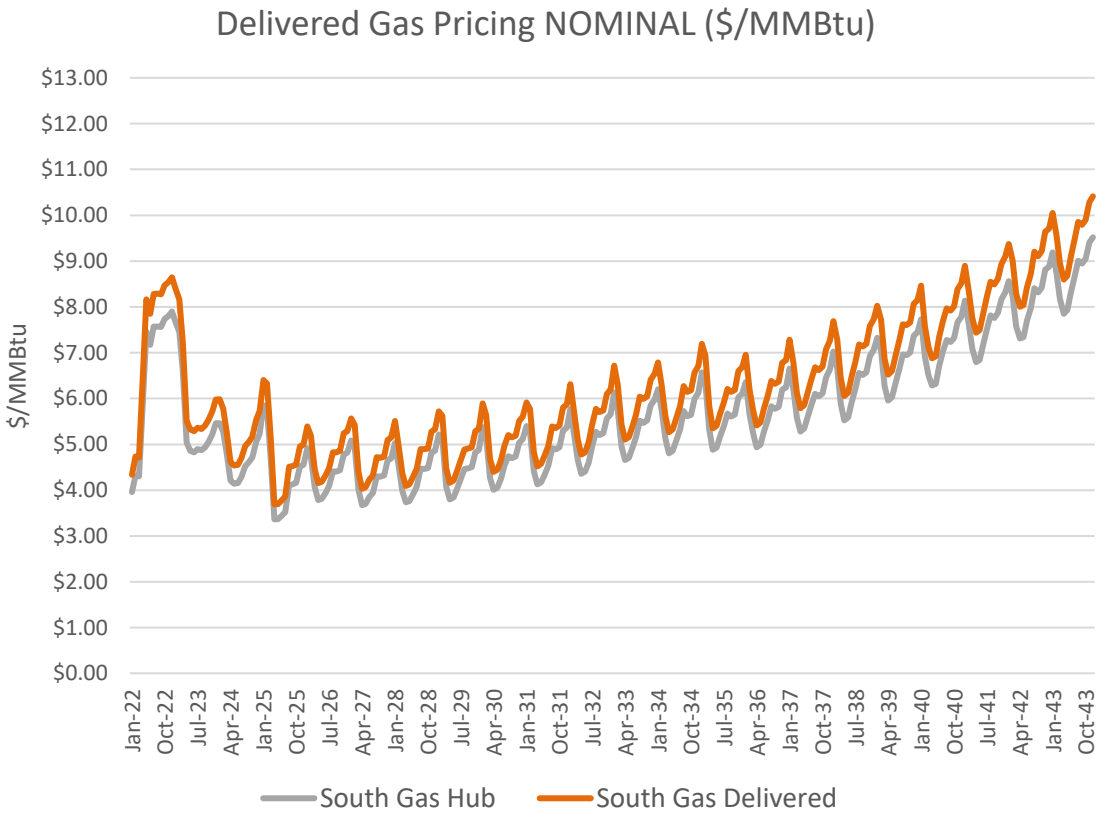
4 Delivered Price Curves

PNM Talk to us. PNM.com

2023 IRP APPLICATION OF NATURAL GAS FORECAST

EXAMPLES FOR DELIVERED NATURAL GAS PRICING



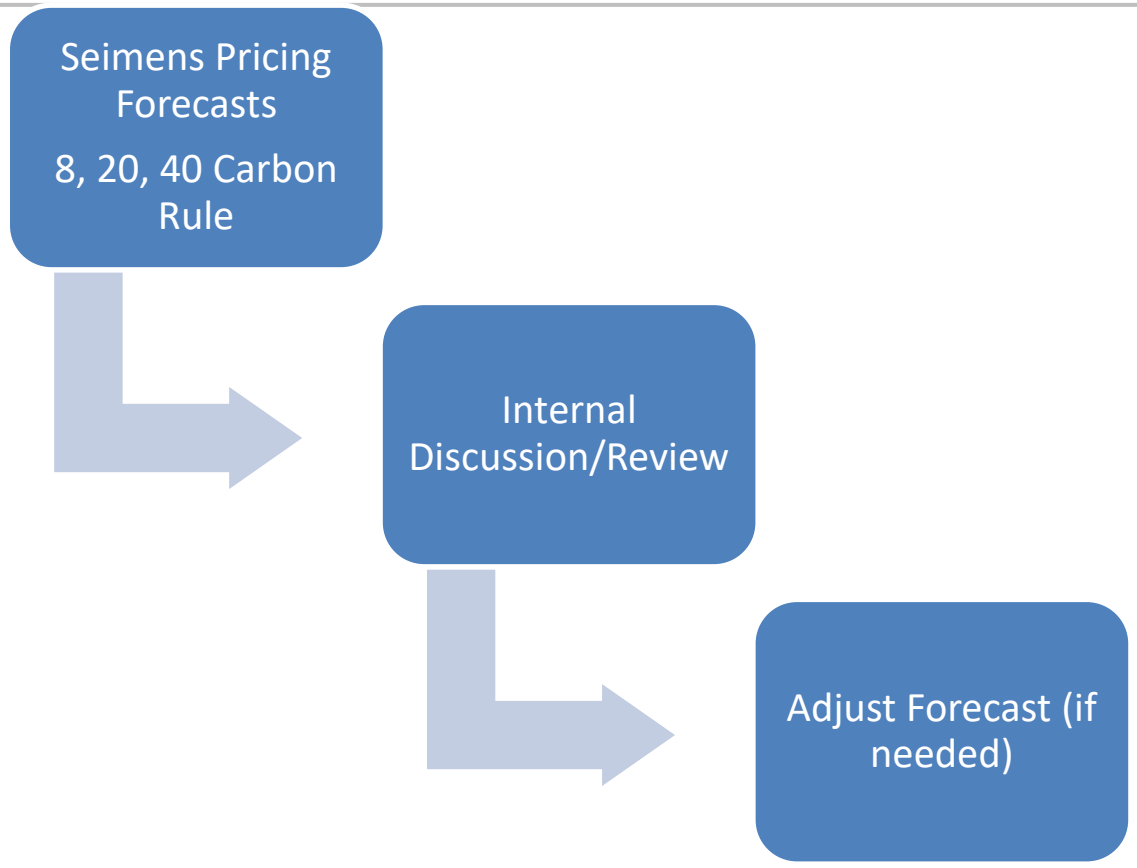


2023 IRP APPLICATION OF SIEMENS FORECASTS

CO2 PRICING FORECAST

We are here

Steps to be completed

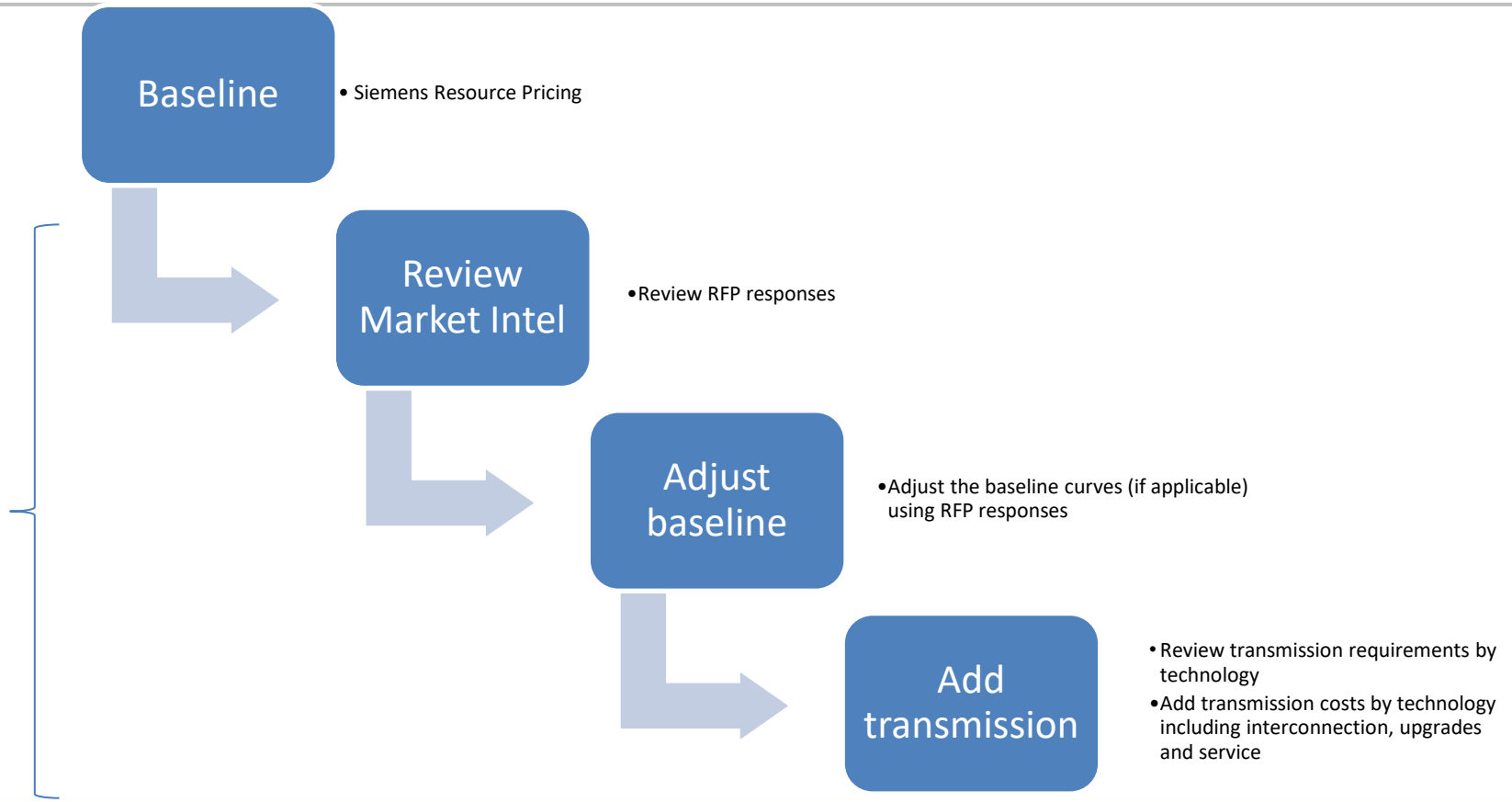


2023 IRP APPLICATION OF SIEMENS FORECASTS

CANDIDATE RESOURCE PRICING

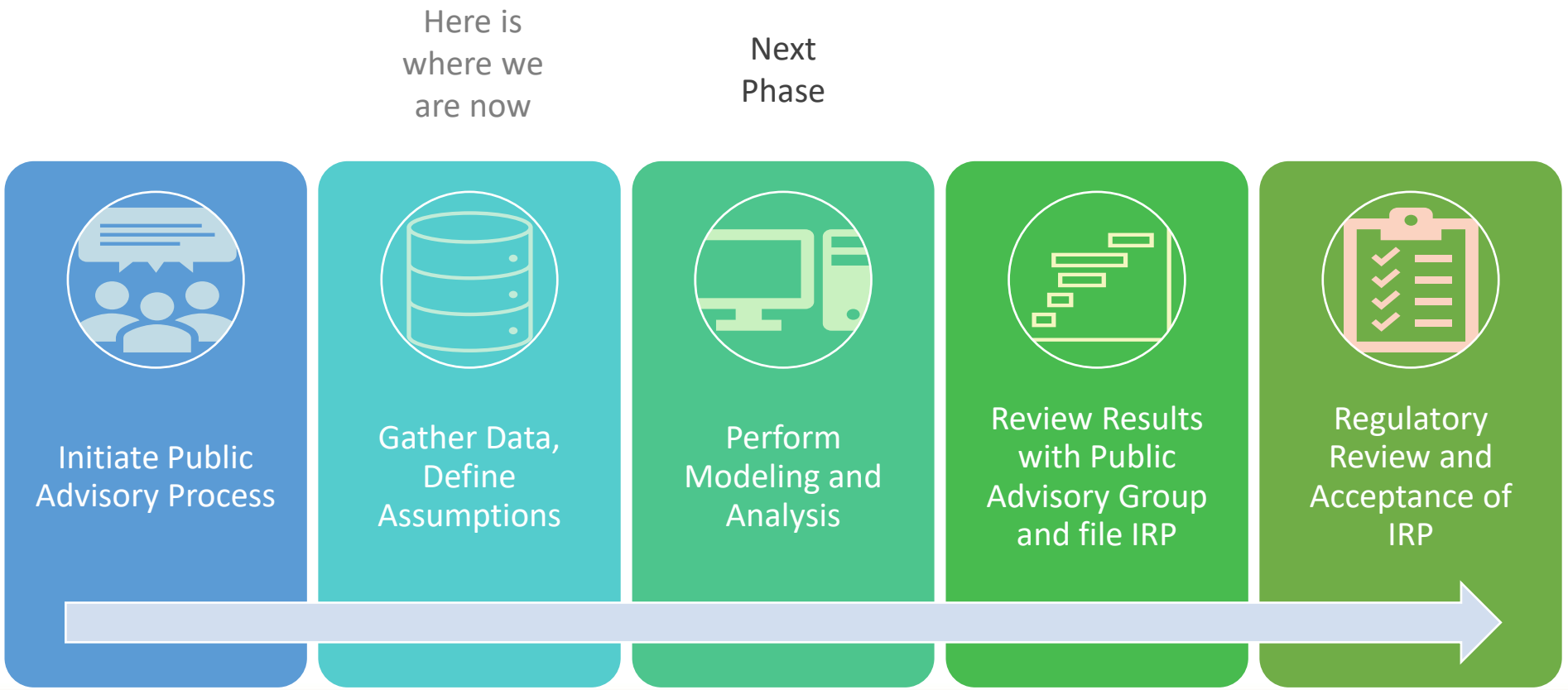
We are here

Steps to be completed



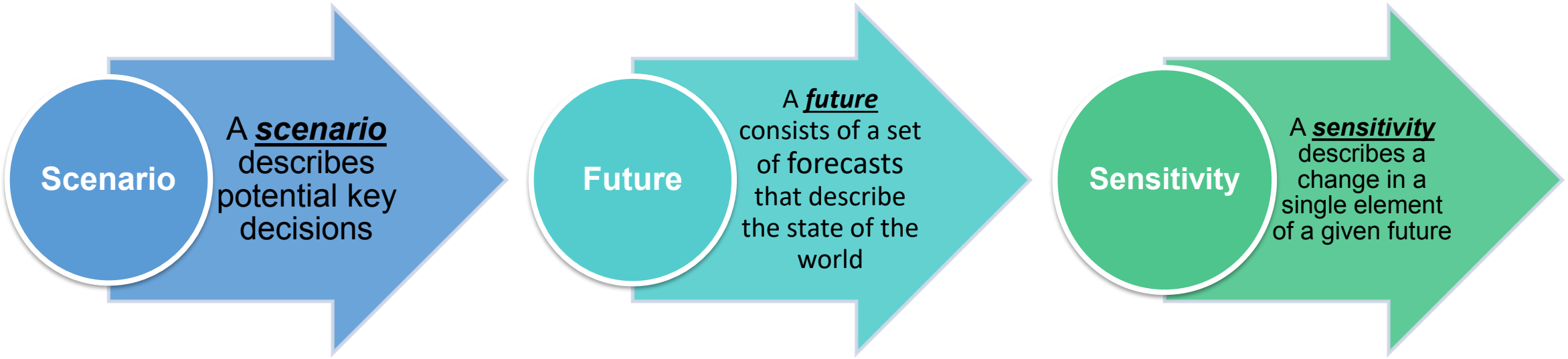
IRP DEVELOPMENT CYCLE

STATUS CHECK



MODELING SCENARIOS

SCENARIO BUILDING – 2023 IRP



Scenarios will allow for IRP to analyze which type of resources or portfolios offer the highest value to customers; it is likely that not all scenarios will need to be evaluated across all futures and sensitivities

SCENARIO FRAMEWORK



Scenarios	Futures	Sensitivities	SON/MCEP/AP
A set of core scenarios that describe key decisions	*Analysis of scenarios under a range of likely futures*	*Stress testing of scenarios under specified futures*	*Evaluation of all scenarios, sensitivities and trends*
Examples: • Addition of long-duration storage • Addition of new transmission line with access to eastern NM wind • Implementation of hydrogen gas	**Examples:** • Current trends & policy • High Economic Growth • Low Economic Grow • Aggressive Environmental Regulation	**Examples:** • Extreme weather (P90 load) • High natural gas prices • Low technology costs • High building electrification • Low carbon costs	**Outcome:** • Develop Statement of Need • Determination of the MCEP • Development of 4-year action plan that supports the MCEP

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: November 16, 2022

Topic: Public Advisory Steering Meeting #9: Modeling Inputs #2: Load Forecast/EE Forecast, EE Bundles & Scenarios

Start Time: 9:00 AM

Location: Virtual

When: December 13, 2022

Topic: Public Advisory Steering Meeting #10: Modeling Input #3: Pricing – TOD, Existing System, RFI & Other regulations

Start Time: 9:00 AM

Location: Virtual

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by November 11, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: Siemens Market Price Outlook, Itron Load Forecast, and Pricing topics

STEERING MEETING #9

DECEMBER 15, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

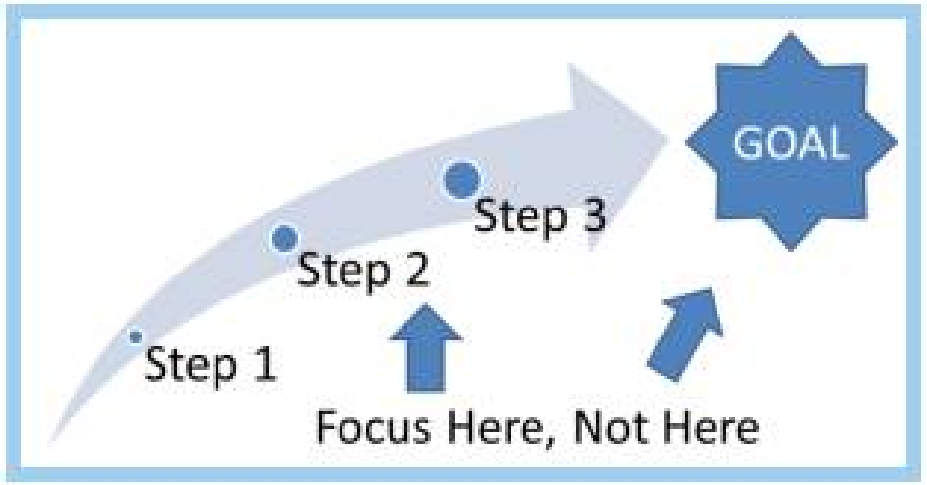
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulatory proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

AGENDA

- Welcome & Introductions
- Siemens – Price Outlook
- Itron – Load Forecast
- PNM Pricing topics – TOU & TOD rates, modern rate design
- Next Steps

Price Outlook

Public Service New Mexico
December 2022

© Siemens 2022

SIEMENS

Introduction

- Siemens PTI developed market assumptions for PNM in July 2022
- Market forecast of natural gas, carbon emission price, and capital costs were developed to assist PNM with its 2023 Integrated Resource Plan (discussion at a prior stakeholder meeting)
- The forecast for each of these commodities was developed based on input from subject matter experts, research, internal analysis, and propriety data over the 2022-2043 planning period

Scenario	Description
Baseline	Reference view based on market forwards early and longer term by fundamentals accounting for expected policy
High	High prices reflect increasing social costs for CO_2 and higher price of natural gas based on statistical analysis
Low	Low prices reflect no costs for CO_2 and lower price of natural gas based on lower band of statistical analysis

Unrestricted © Siemens AG 2022

Market Drivers

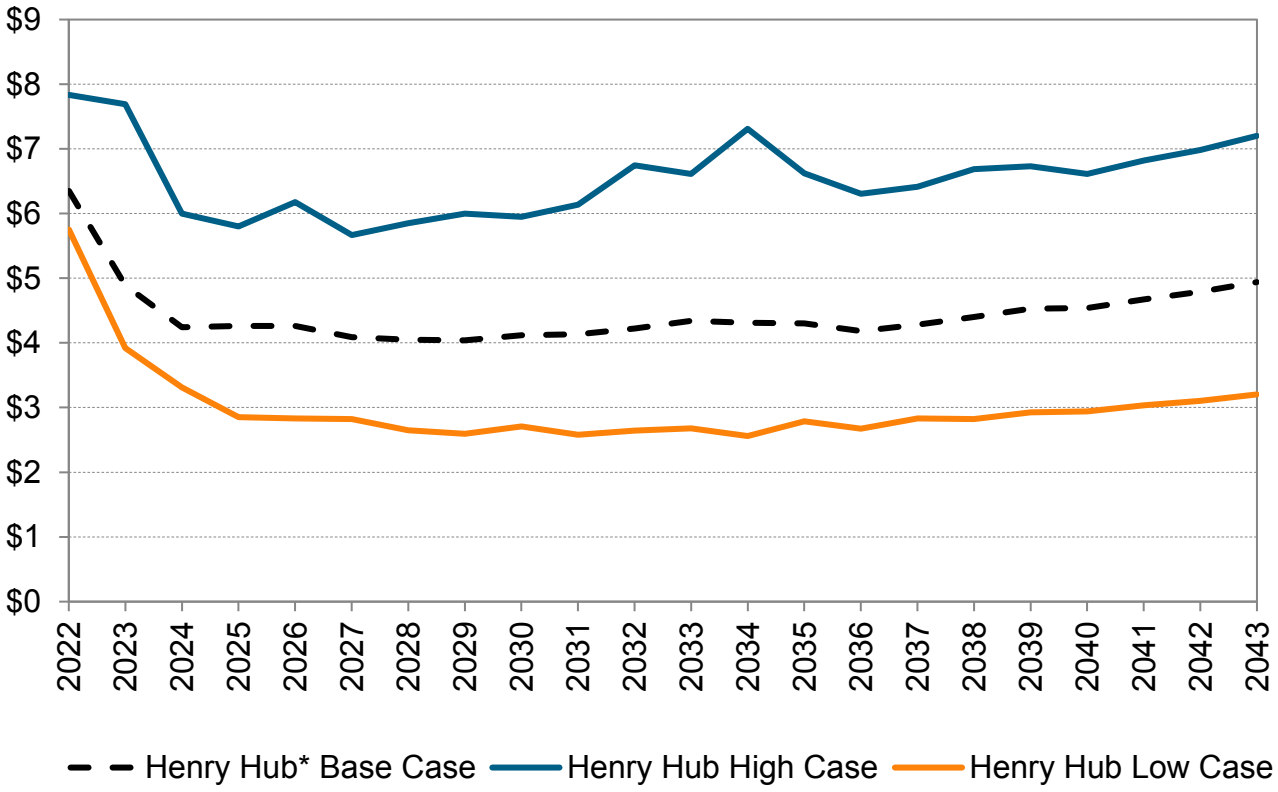
Gas and CO2 price scenarios

Unrestricted © Siemens AG 2022

SIEMENS

Natural Gas Price Scenarios – Henry Hub

HH Natural Gas Price Scenarios, $2021/MMBtu



*Base case prices were developed using NYMEX forwards for Henry Hub for the first 18 months starting July 2022, mix of forward and fundamentals for next 18 months; fundamentals March 2025 onwards

Henry Hub Low and High Cases

Low Case –Reflects an outlook based on a statistical analysis of historical at the 10% confidence internal. Prices settle around $3/MMBtu longer term

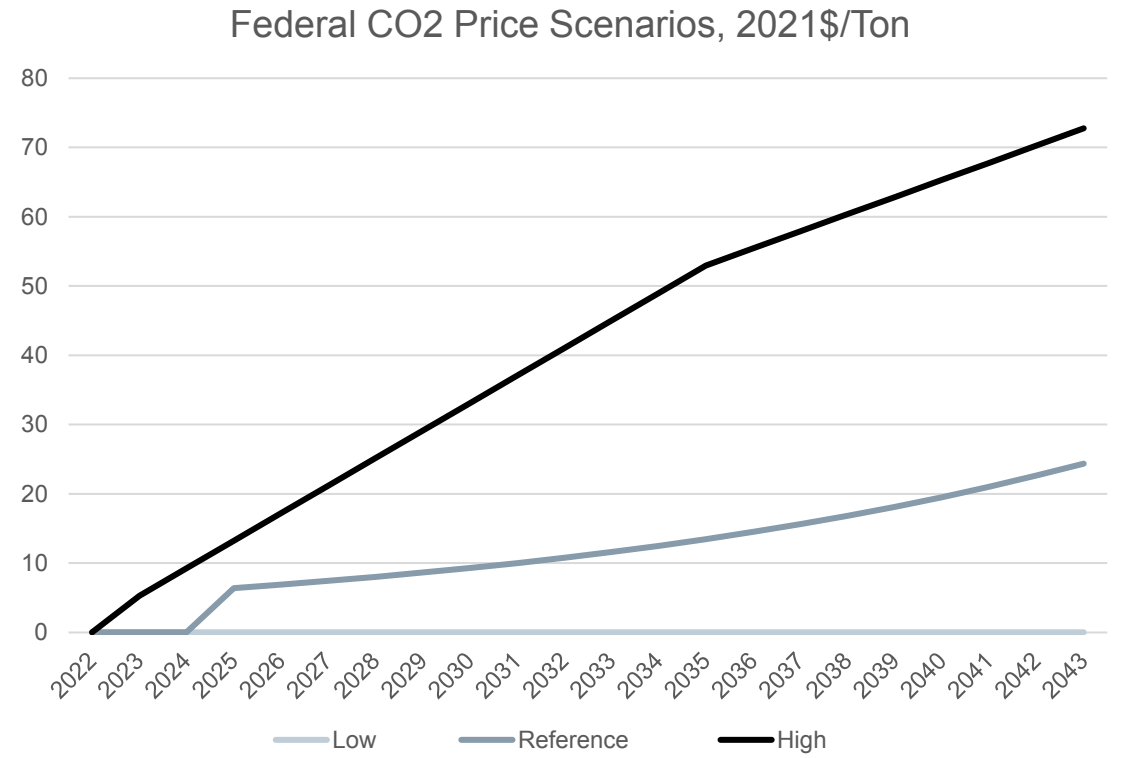
High Case – Reflects an outlook based on Statistical analysis of historical at 90% confidence interval. Prices increase above ~$6/MMBtu longer term

Unrestricted © Siemens AG 2022

Carbon Price Scenarios – Federal

- Range of federal carbon prices reflects uncertain outlook for carbon policy and resulting pricing in western states
- Baseline scenario assumes a carbon policy starting in 2025 to achieve 80% reduction in carbon emission in the power sector relative to 2005 levels
- High scenario nears $70/ton by the end of the forecast horizon and incorporates social cost of carbon emission
- Low case represents no cost for carbon emission

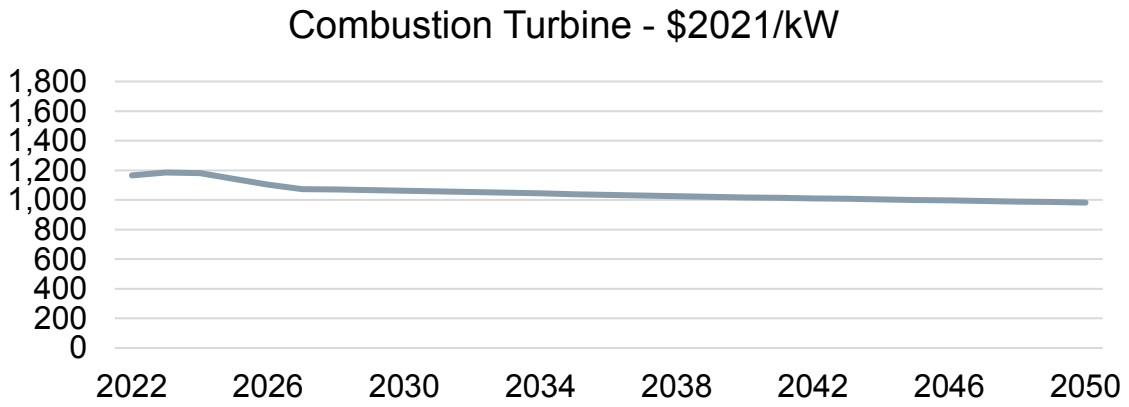
U.S. Carbon Price Scenarios

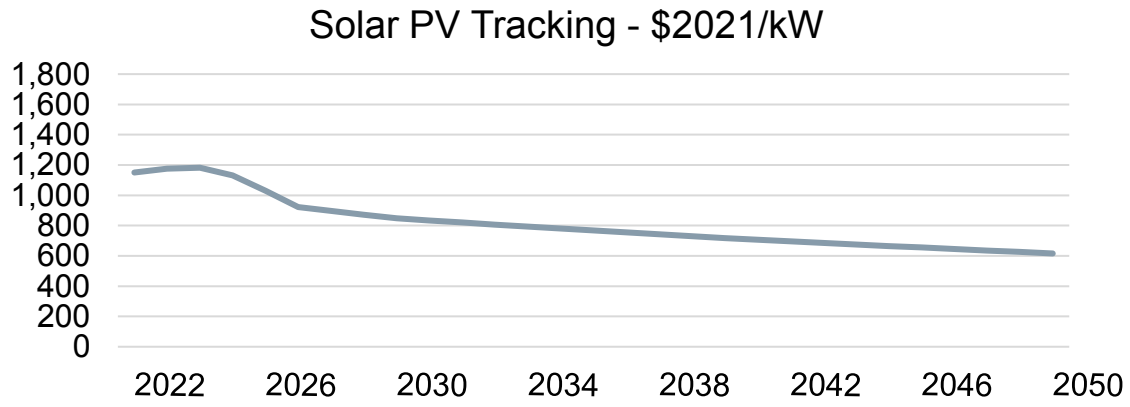


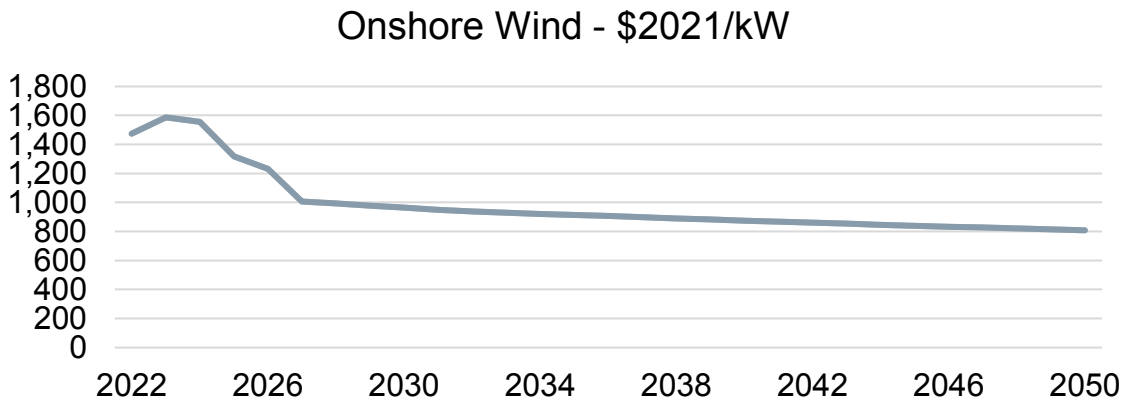
Unrestricted © Siemens AG 2022

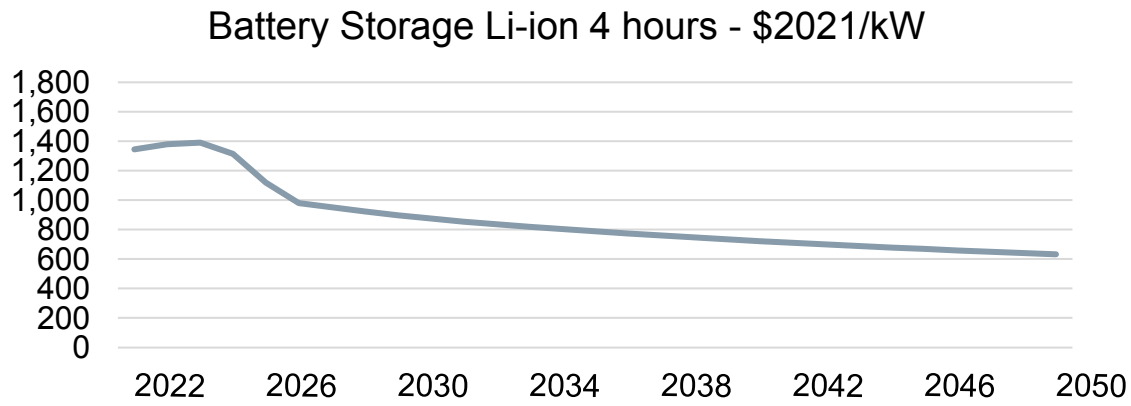
Capital cost forecast for select technologies incorporates regional factors to build in New Mexico

**Costs outlook does not reflect incentives provided by the Inflation Reduction Act 2022*









Unrestricted © Siemens AG 2022

SIEMENS
Siemens Energy Business Advisory

Power Price Outlook

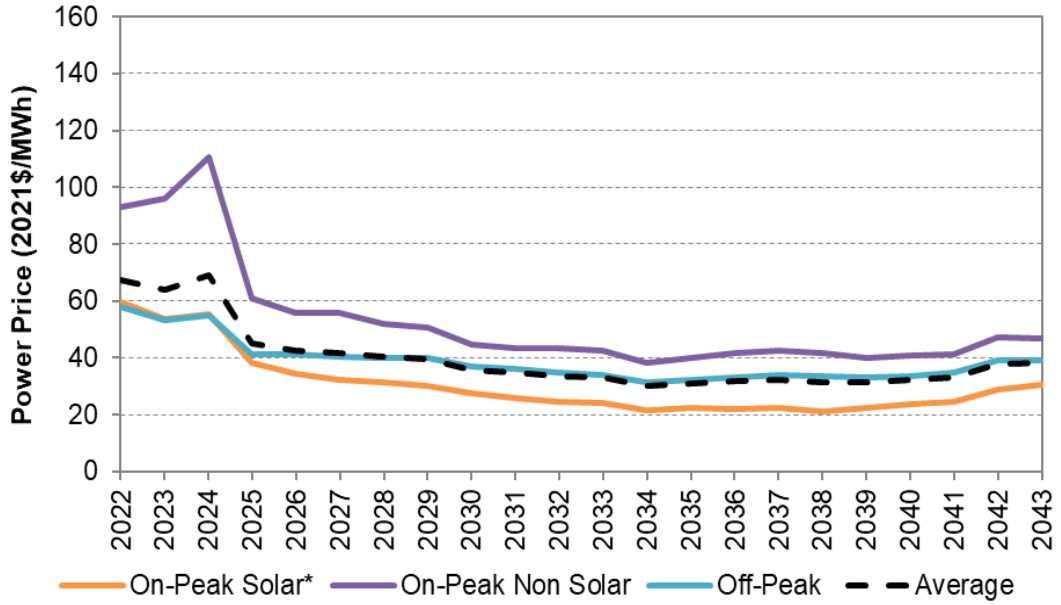
Unrestricted © Siemens AG 2022

SIEMENS

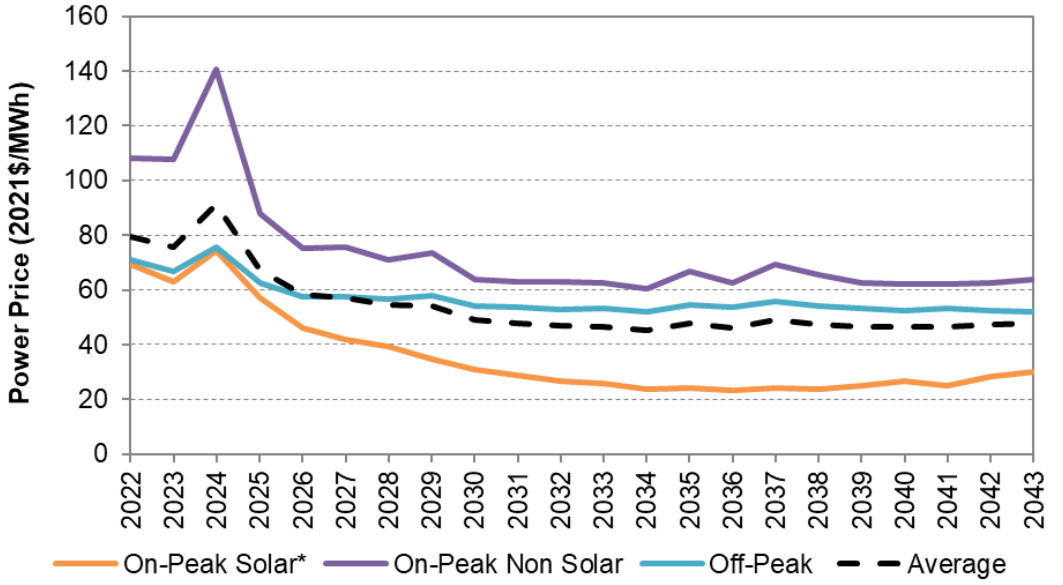
Baseline Zonal Energy Prices – Annual

- **Near Term** – High pricing reflected in recent and forward market pricing supported by higher natural gas prices and scarcity pricing due to supply chain issues
- **Mid-Term** – On-peak energy prices decline driven by an increase in solar capacity, reducing prices in many hours of the peak period. Off-peak prices remain stable to decreasing with natural gas prices through the mid-2020s.
- **Long-Term** – All-hours energy prices remain fairly flat on the expectation of no real additional increase in gas prices while the impact from solar to on-peak prices widens.

Four Corners Annual Pricing



Palo Verde Annual Pricing



*On-peak solar defined as the hours of 8 A.M. to 5 P.M.

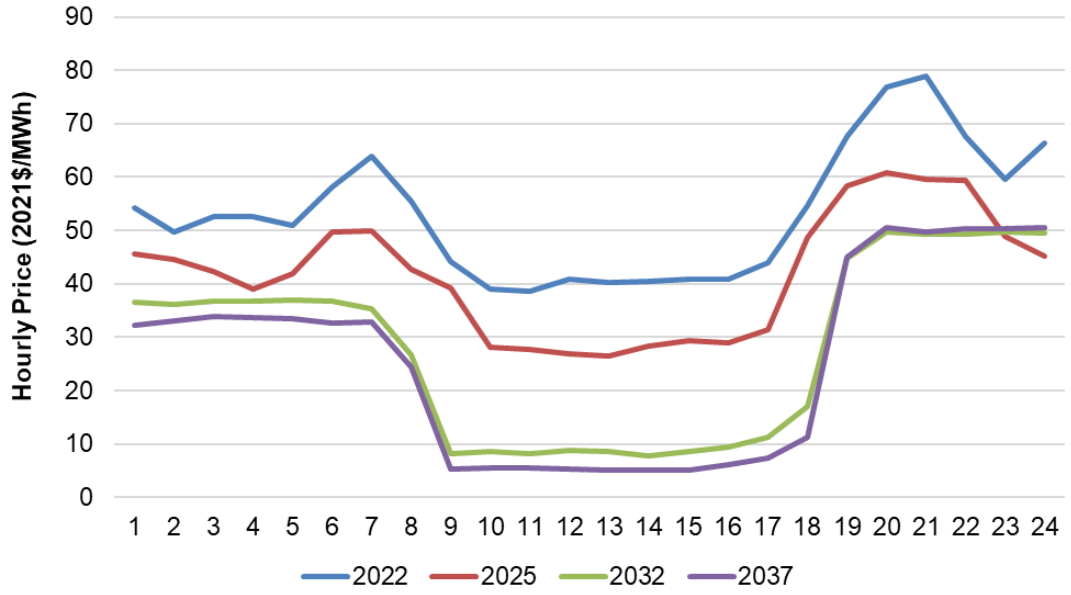
Unrestricted © Siemens AG 2022

Increased Solar Penetration Exacerbates Duck Curve Resulting in Lower On-Peak Energy Prices

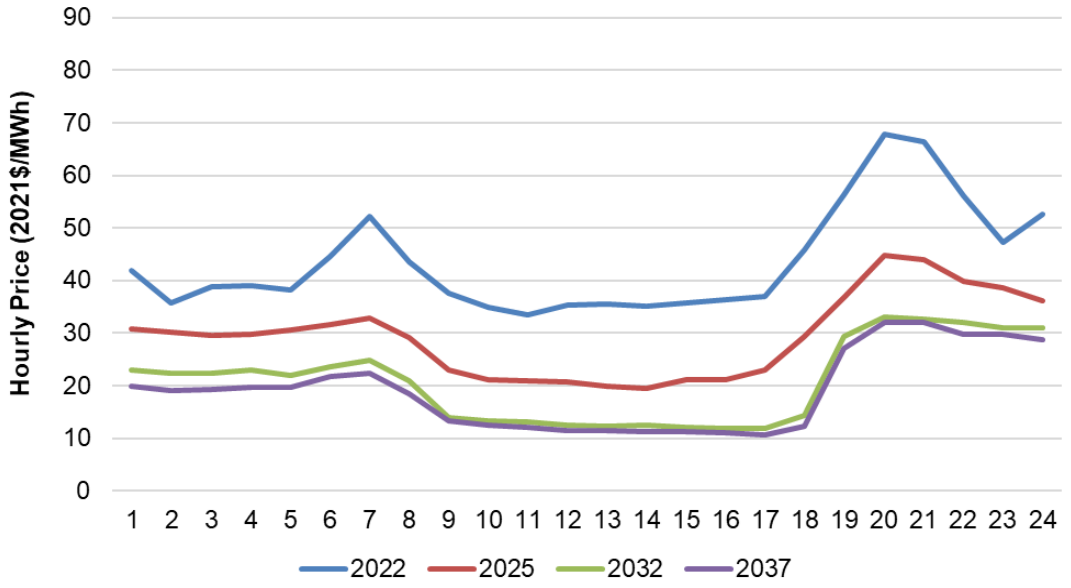
SIEMENS
Ingenuity for life

- With growth in solar generation expected to exceed electricity demand growth, the duck curve is expected to increase.
- Peak solar hours, from 8 A.M. to 5 P.M., will experience price drop while the balance of peak power hours are expected to see higher prices.

Palo Verde Average Hourly Pricing (April)



Four Corners Average Hourly Pricing (April)



Unrestricted © Siemens AG 2022

Base Case Pricing and Market Fundamentals Summary

SIEMENS
Ingenuity for life

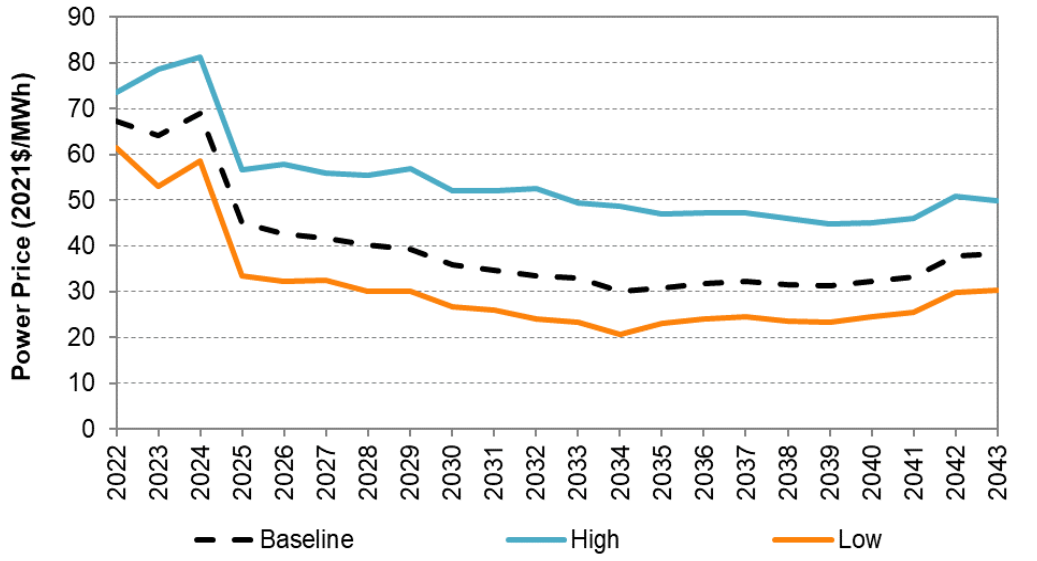
- Forward pricing for Four Corners and Palo Verde are currently higher than historical values due to scarcity pricing and high fuel costs
- RPS and carbon reduction requirements are expected to support high renewable adoption resulting in lower on-peak pricing
- Under the Baseline Case, new builds in the region are largely solar, storage, and fast-ramping gas units based on economics
- On-peak pricing outside of solar hours and off-peak pricing is expected to remain higher yet stable over time
- All-hours pricing is expected to decrease from current high levels through the 2020s and remains flat thereafter
- With the growth in solar generation expected to exceed electricity demand growth, the duck curve is expected to increase.
- Peak solar hours, from 8 A.M. to 5 P.M., will experience a price drop while the balance of peak power hours is expected to see higher prices.

Unrestricted © Siemens AG 2022

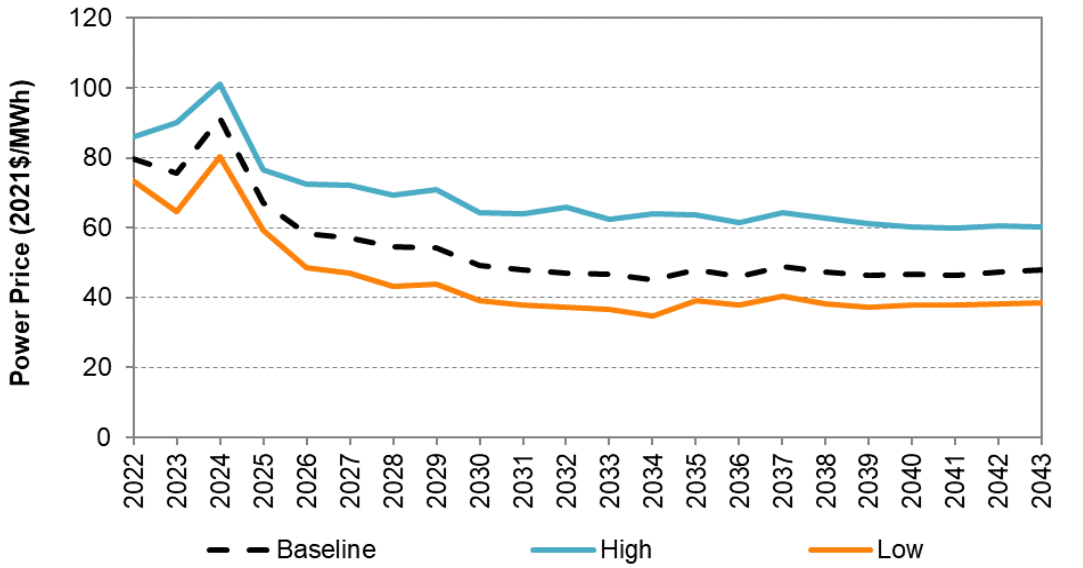
Zonal Energy Price Scenarios – Four Corners and Palo Verde

- Higher natural gas prices in the mid-and long-term as well as higher carbon prices in the long-term support higher energy pricing in the High Case
- The absence of a carbon price and sustained lower natural gas prices over the forecast period support energy pricing remaining at, near, or below current levels over the forecast period in the Low Case

Four Corners



Palo Verde



Unrestricted © Siemens AG 2022

© Siemens 2022

Contact



Anuj Patel

Principal

Mobile: (281) 939-2144

Email: Anuj@siemens.com



Chelsea LaRicci

Project Manager

Email: Chelsea.Laricci@siemens.com

Unrestricted © Siemens AG 2022

SIEMENS



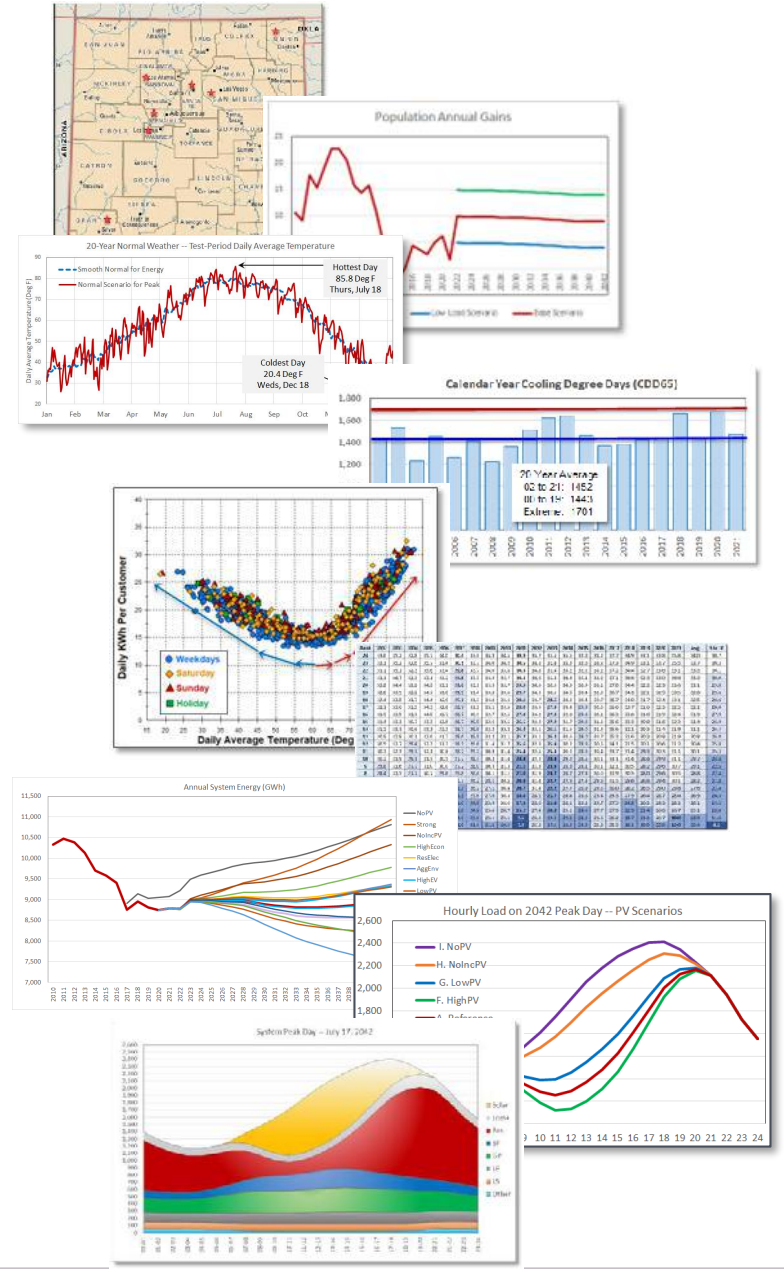
Draft PNM Integrated Resource Plan Forecast Scenarios

Stuart McMenamin
Itron, Inc.

December, 2022

Agenda

- Economic Data and Forecasts
- Weather Data, Normal and Extreme Weather
- Behind the Meter PV Data and Forecasts
- Electric Vehicle Forecast
- Other Scenario Inputs (Electrification, TOU)
- Energy Modeling and Forecasts
  - Customer growth forecast
  - Statistically Adjusted End Use (SAE) Method
  - Use per customer models
  - Energy and peak forecast summary
- Hourly System Load and Peak Demand Forecasts
  - Bottom-up load shape and peak demand forecast
- Forecast Scenarios and Results



Economic Data and Forecasts

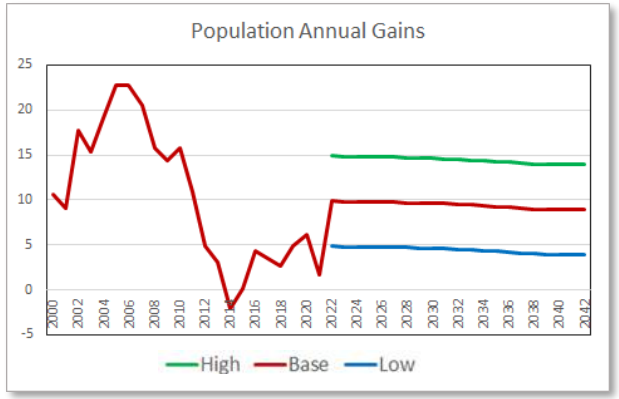
Economic Data and Forecast

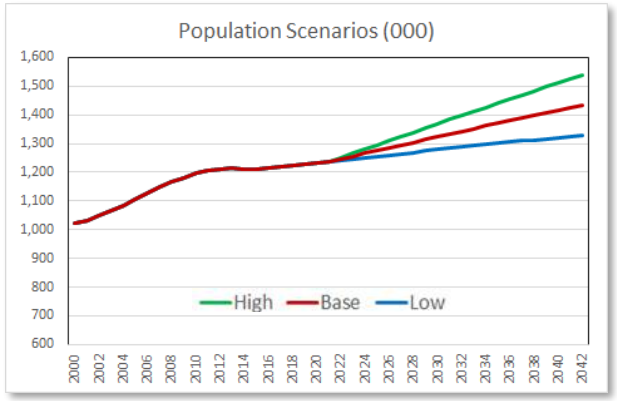
- Forecast provided by Woods and Poole
- Annual history from 1950 to 2021
- Annual forecast to 2050
- State and County level data
- Used data for PNM counties:
  - North: Bernalillo, San Miguel, Sandoval Santa Fe, Union, Valencia
  - South: Grant, Hidalgo, Luna, Otero
- Annual data converted to monthly using centered moving averages

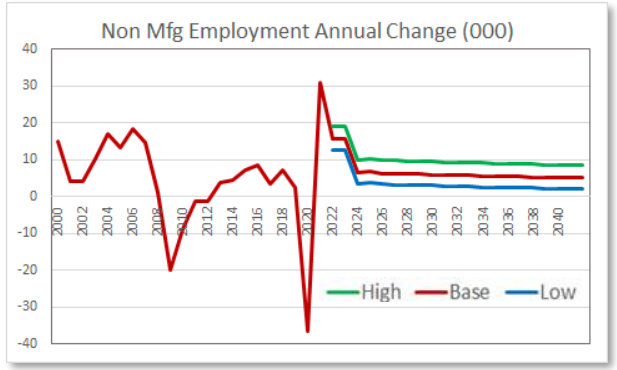


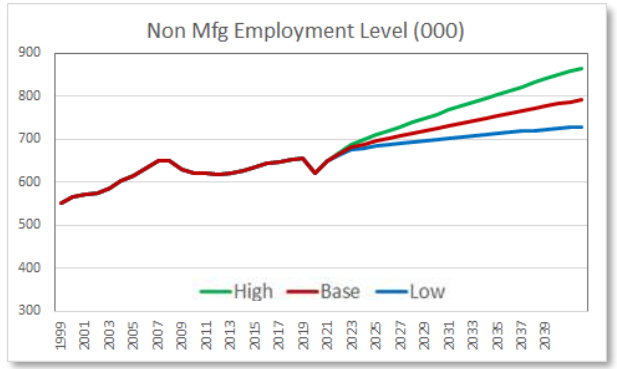
Economic Scenarios

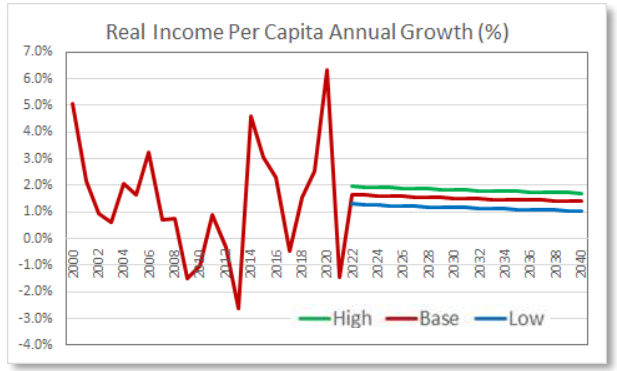
- Population Annual Gains
  - High Case: 14,400
  - Base Case: 9,400
  - Low Case: 4,400
- Non Mfg. Employment Annual Gains
  - High Case: 9,300
  - Base Case: 5,800
  - Low Case: 2,800
- Real Per Capita Income Growth
  - High Case: 1.8%
  - Base Case: 1.5%
  - Low Case: 1.1%

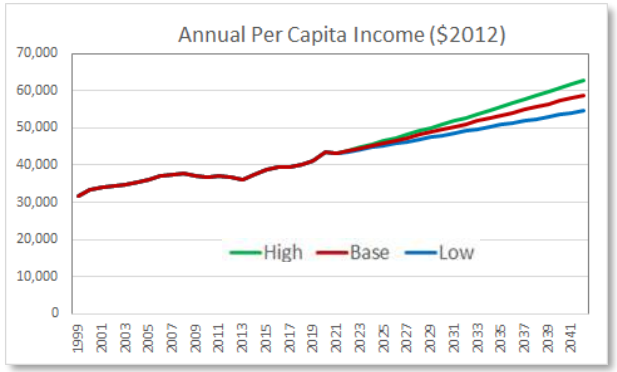






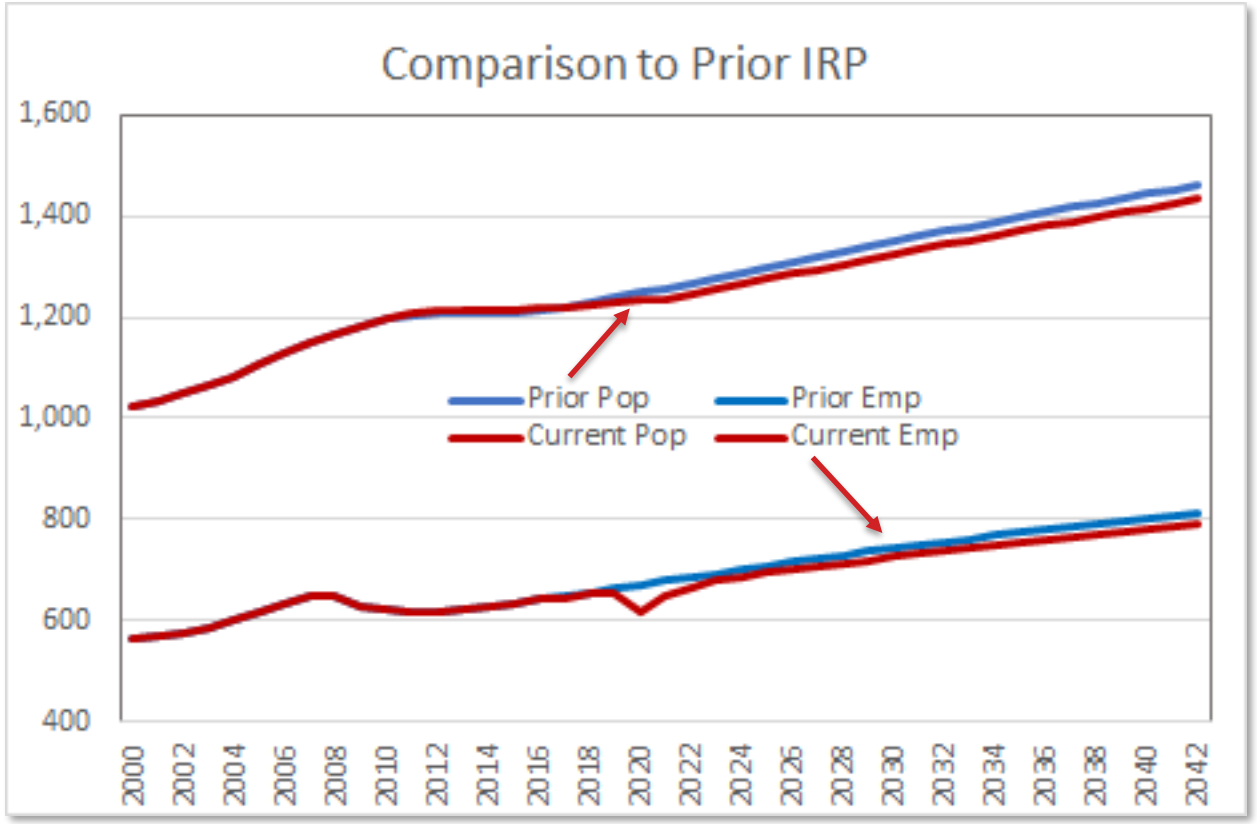






Comparison with Prior IRP

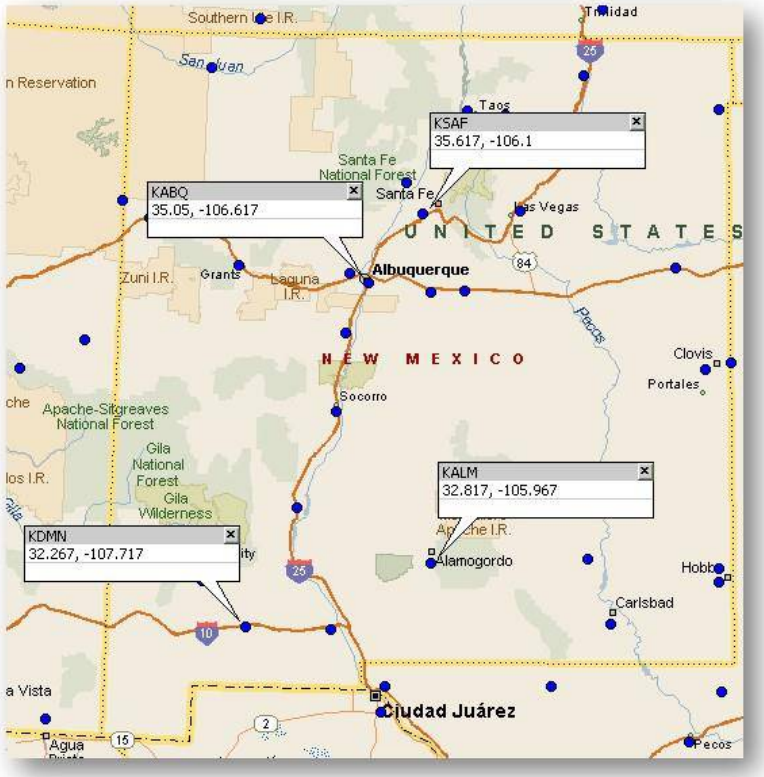
- Main drivers of growth are Population and Nonmanufacturing Employment
- Current forecasts are slightly weaker
  - Population in 2042 down 28k
  - Employment in 2042 down 19k
- Most of the difference is in place by the end of 2022, so gains beyond 2022 are about the same.



Weather Data and Normal Weather

Weather Data and Daily Scenarios

- Hourly weather data from AccuWeather
  - Temperature – Used to compute Degree Days
  - Global horizontal irradiation (GHI) – Used for solar generation
- 4 Stations
  - North: Albuquerque (KABQ), Santa Fe (KSAF)
  - South: Deming (KDMN), Alamogordo (KALM)
- Station weights for weather variables
  - Based on monthly billed sales
  - Heating Degree weights based on winter sales
  - Cooling Degree weights based on summer sales
  - Solar GHI weights based on annual sales



Station	Heating Degrees	Cooling Degrees	Solar GHI
KABQ	75.0%	77.8%	76.3%
KALM	3.0%	3.2%	3.1%
KDMN	9.0%	8.4%	8.9%
KSAF	13.0%	10.5%	11.7%

Hottest Days 2002 to 2021 (Rank by Season)

Rank	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Avg	1 in 10
1	84.8	87.5	82.6	83.6	85.1	84.4	83.2	85.2	85.4	84.8	87.1	89.0	86.5	86.5	86.2	87.6	86.7	84.8	**87.8**	86.3	85.8	88.4
2	84.6	**86.9**	81.7	83.2	84.5	84.2	83.1	85.0	85.1	84.8	86.5	86.5	85.4	85.0	85.4	86.8	85.5	84.7	**87.6**	85.9	85.1	87.2
3	83.8	85.9	81.2	82.9	83.7	83.4	82.3	84.9	84.9	84.7	85.1	85.6	83.8	83.0	84.9	**85.9**	85.2	84.7	**86.8**	85.8	84.4	86.3
4	83.6	**85.8**	81.2	82.7	83.6	83.1	82.3	84.5	84.5	84.6	84.5	84.4	83.6	82.8	84.7	83.6	85.2	83.7	85.4	85.6	84.0	85.7
5	82.5	**85.6**	81.0	82.7	83.6	83.1	82.0	84.3	84.4	84.3	84.4	84.2	82.3	82.4	84.6	83.6	84.8	83.4	**84.8**	84.5	83.6	85.2
6	82.4	**85.5**	80.8	82.3	83.5	82.9	81.7	83.9	83.8	84.2	84.3	83.2	82.0	82.0	84.5	83.5	**84.5**	82.9	83.8	84.4	83.3	85.0
7	82.0	**85.3**	80.7	82.1	83.3	82.9	81.7	83.8	83.7	84.1	84.0	82.9	81.9	81.8	**84.3**	83.4	83.7	82.9	83.8	84.3	83.1	84.8
8	82.0	**85.0**	80.6	82.0	83.0	82.8	81.6	83.7	82.8	83.9	**83.9**	82.0	81.7	81.8	84.3	83.1	83.7	82.8	83.5	84.3	82.9	84.4
9	81.7	**84.8**	80.5	82.0	82.9	82.8	81.1	83.5	82.8	83.7	**83.8**	82.0	81.5	81.3	84.1	83.0	83.5	82.1	83.5	83.5	82.7	84.3
10	81.6	**84.4**	80.3	81.9	82.9	82.5	80.8	83.0	82.7	83.6	83.7	81.8	81.3	81.2	**83.8**	82.9	83.4	81.9	83.5	83.2	82.5	84.1
11	81.4	**84.4**	80.2	81.8	82.7	82.5	80.6	82.9	82.5	83.5	**83.6**	81.6	81.1	81.1	83.6	82.9	83.1	81.7	83.3	82.2	82.3	84.0
12	81.4	**84.1**	80.1	81.8	82.6	82.3	80.5	82.9	82.3	**83.5**	83.3	81.3	81.1	80.8	83.5	82.3	83.0	81.6	83.1	82.0	82.2	83.8
13	81.3	**83.6**	80.0	81.6	82.0	82.1	80.4	82.5	82.2	83.0	83.2	81.3	81.0	80.8	**83.4**	82.1	82.8	81.5	82.7	81.9	82.0	83.5
14	81.1	**83.6**	80.0	81.6	82.0	82.1	80.3	82.2	82.0	82.9	83.0	81.3	81.0	80.7	**83.3**	81.7	82.7	81.5	82.6	81.6	81.9	83.5
15	80.9	**83.4**	79.7	81.5	81.8	82.0	79.7	82.0	81.9	82.9	82.9	81.2	80.7	80.6	**83.2**	81.4	82.7	81.3	82.5	81.3	81.7	83.3
16	80.7	**83.4**	79.5	81.4	81.7	82.0	79.6	81.1	81.8	82.8	82.8	81.2	80.3	80.1	**83.2**	81.0	82.7	81.3	82.4	80.9	81.5	83.3
17	80.7	**83.3**	79.4	81.1	81.5	81.4	79.0	80.8	81.4	**82.8**	82.7	81.0	80.3	80.1	82.6	80.8	82.0	81.1	82.3	80.9	81.3	83.0
18	80.7	**83.2**	79.2	81.1	81.4	81.2	79.0	80.7	81.4	**82.7**	81.8	80.8	80.3	80.0	82.4	80.2	81.9	81.1	82.3	80.7	81.1	83.0
19	80.5	**82.8**	79.2	80.9	81.2	81.1	79.0	80.7	81.3	**82.7**	81.8	80.3	80.2	79.9	82.3	80.1	81.7	81.0	82.1	80.5	81.0	82.7
20	80.4	**82.4**	79.2	80.7	81.0	80.9	78.8	80.7	80.8	**82.7**	81.6	80.2	79.9	79.9	82.2	80.0	81.7	80.8	82.1	80.1	80.8	82.6
21	80.3	**82.4**	79.1	80.6	80.9	80.8	78.6	80.3	80.6	**82.3**	81.4	80.2	79.7	79.6	82.1	80.0	81.6	80.7	82.1	80.0	80.7	82.3
22	80.3	**82.4**	79.0	80.5	80.4	80.7	78.5	79.9	80.5	**82.2**	81.1	80.1	79.6	79.4	82.0	79.8	81.5	80.6	81.9	79.7	80.5	82.3
23	80.2	**82.3**	78.9	80.5	80.2	80.6	78.3	79.9	80.4	**82.2**	81.1	80.1	79.4	79.4	81.7	79.6	81.4	80.6	81.9	79.5	80.4	82.3
24	80.1	**82.2**	78.8	80.4	80.0	80.6	78.3	79.9	80.2	**82.1**	81.0	80.0	79.3	79.3	81.6	79.6	81.0	80.5	81.6	79.3	80.3	82.2

>88

>85

>82

Used in Base Scenario

Used in Extreme Scenario

Coldest Days 2002-2021 (Rank by Season)

Rank	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Avg	1 in 10
24	33.6	35.2	32.8	35.7	34.0	**30.4**	33.8	34.9	34.5	**30.9**	35.7	31.5	35.5	32.8	33.2	37.7	34.9	33.1	33.8	35.8	34.0	30.7
23	33.1	35.2	32.6	35.7	33.4	**30.1**	33.7	34.0	34.2	**30.5**	34.8	31.4	35.3	32.6	33.2	37.3	34.9	33.1	33.7	35.5	33.7	30.3
22	33.1	35.1	32.3	35.6	33.4	**29.8**	33.7	34.0	33.8	**30.3**	34.8	31.4	35.2	32.2	33.2	37.2	34.4	32.7	33.6	35.1	33.5	30.1
21	33.1	34.7	32.3	35.1	33.2	**29.8**	33.3	33.9	33.7	**30.3**	34.6	31.3	34.9	32.1	33.2	37.1	34.4	32.3	33.0	34.4	33.3	30.0
20	32.8	34.4	32.2	34.8	33.1	**29.6**	33.1	33.9	33.7	**29.9**	34.6	30.5	34.9	30.9	33.1	37.0	34.4	32.2	32.9	33.6	33.1	29.8
19	32.8	33.9	32.2	34.7	33.0	**29.5**	31.4	33.8	33.6	**29.7**	34.3	30.5	34.9	30.4	32.9	36.7	34.3	32.1	32.9	33.5	32.8	29.6
18	32.4	33.8	31.7	34.4	32.9	29.1	31.3	33.8	33.6	**28.6**	33.7	**28.6**	34.3	30.4	32.7	36.7	34.0	31.7	32.4	33.1	32.5	28.6
17	32.1	33.6	31.5	34.3	32.8	28.7	31.1	33.1	33.5	**28.0**	33.5	**27.9**	33.4	29.9	32.5	36.6	33.7	31.6	32.3	32.5	32.1	28.0
16	31.9	33.5	31.3	34.0	32.7	28.7	30.9	32.7	32.5	**27.8**	33.2	**27.9**	32.8	29.8	32.1	36.3	33.6	31.0	31.9	32.4	31.9	27.9
15	31.4	33.3	30.7	33.3	32.5	28.7	29.9	32.6	32.5	**26.5**	33.2	**27.2**	31.7	29.2	31.5	35.6	33.3	30.8	31.6	32.3	31.4	26.9
14	31.2	33.1	30.6	33.1	32.3	28.7	29.9	32.2	32.2	**26.4**	33.1	**26.5**	31.5	29.0	31.3	35.6	32.1	30.3	31.4	31.9	31.1	26.4
13	30.9	32.8	30.1	32.6	31.7	28.6	29.8	32.2	32.1	**25.7**	33.1	**26.2**	30.6	29.0	30.7	35.3	31.6	30.3	30.8	31.9	30.8	26.0
12	30.5	32.7	29.4	32.3	31.3	28.3	29.6	31.4	31.7	**25.6**	32.8	**25.9**	30.2	28.9	30.5	34.1	31.5	30.1	30.6	31.2	30.4	25.8
11	30.2	32.3	29.3	32.1	30.8	28.2	29.2	30.9	31.4	**25.4**	32.5	**25.3**	30.2	28.6	30.4	33.7	31.4	29.3	30.3	31.1	30.1	25.3
10	30.2	31.9	29.1	31.3	30.5	27.7	28.3	30.3	31.4	**24.4**	32.2	**24.4**	29.2	28.5	30.1	33.1	31.4	28.4	29.9	31.1	29.7	24.4
9	29.8	31.6	27.7	31.0	30.0	27.2	28.0	30.3	31.3	**21.1**	31.9	**23.9**	28.9	28.1	30.1	32.1	30.5	28.2	29.6	30.7	29.1	22.5
8	28.4	31.3	27.7	30.7	29.6	25.8	26.6	30.1	31.1	**21.0**	31.9	**23.7**	28.7	27.9	30.0	31.9	30.5	28.0	29.6	30.5	28.8	22.4
7	28.3	31.1	27.0	30.6	29.5	25.7	26.2	28.1	30.5	**20.9**	31.4	**22.7**	27.9	27.3	29.5	31.5	29.6	26.8	29.4	30.1	28.2	21.8
6	28.3	30.0	26.0	30.0	29.2	23.3	26.2	27.1	30.4	**20.7**	31.4	**22.2**	27.7	26.9	29.5	30.0	28.2	26.5	29.0	29.8	27.6	21.4
5	27.9	29.2	24.7	29.9	29.1	23.1	25.6	27.0	30.3	**18.8**	28.1	**21.7**	26.4	26.8	29.4	29.3	27.9	26.4	28.7	28.4	26.9	20.3
4	26.8	29.1	24.2	28.7	29.0	22.0	24.8	25.9	30.0	**17.3**	28.0	**21.4**	26.1	25.3	28.7	27.5	24.2	26.2	28.3	28.1	26.1	19.3
3	26.3	28.6	22.7	28.6	28.9	21.8	24.2	25.6	28.7	**15.2**	27.4	**20.9**	25.1	24.6	27.7	27.3	22.9	21.4	26.8	26.7	25.1	18.0
2	24.5	24.6	22.5	25.2	23.4	21.3	23.6	25.1	25.1	**5.2**	26.3	19.3	22.1	24.5	26.6	26.2	18.7	21.1	26.7	**18.0**	22.5	11.6
1	24.4	23.2	20.6	21.1	20.2	21.0	21.4	21.5	19.5	**3.5**	25.8	17.1	18.9	24.2	25.8	25.3	18.1	19.9	22.8	**12.9**	20.4	**8.2**

Used in Base Scenario

Used in Extreme Scenario

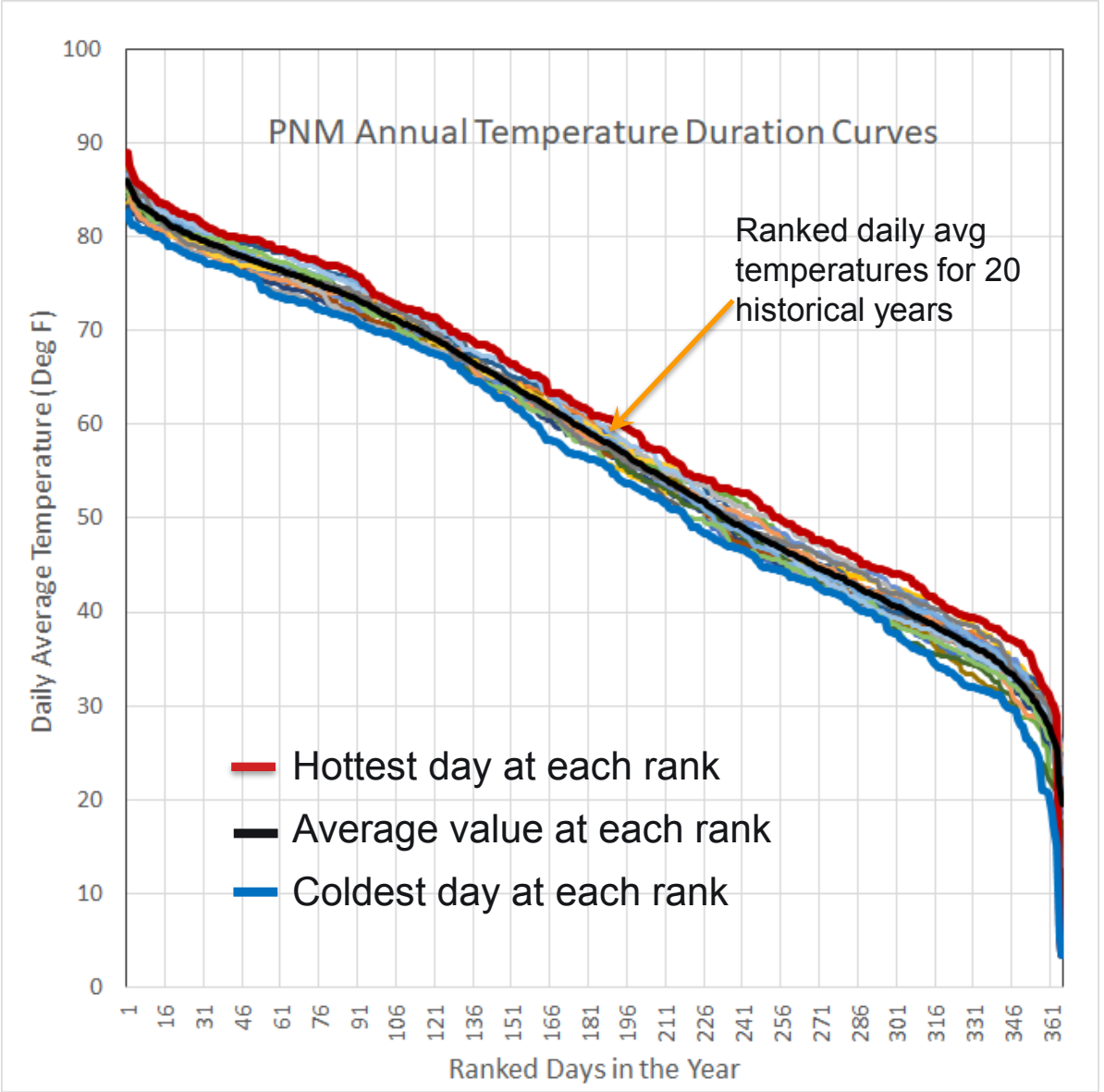
<30

<25

<10

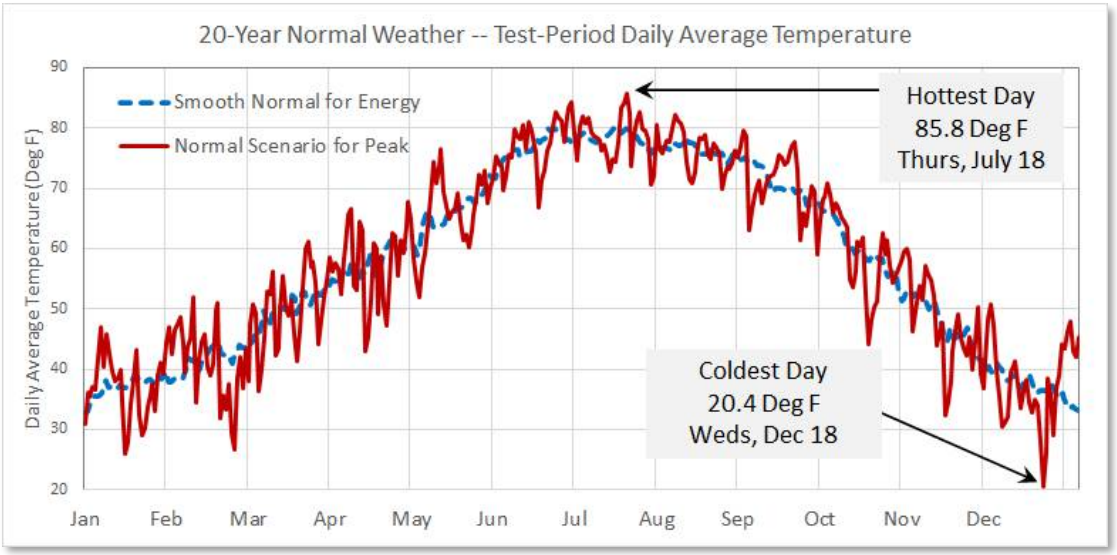
WEATHER SCENARIOS

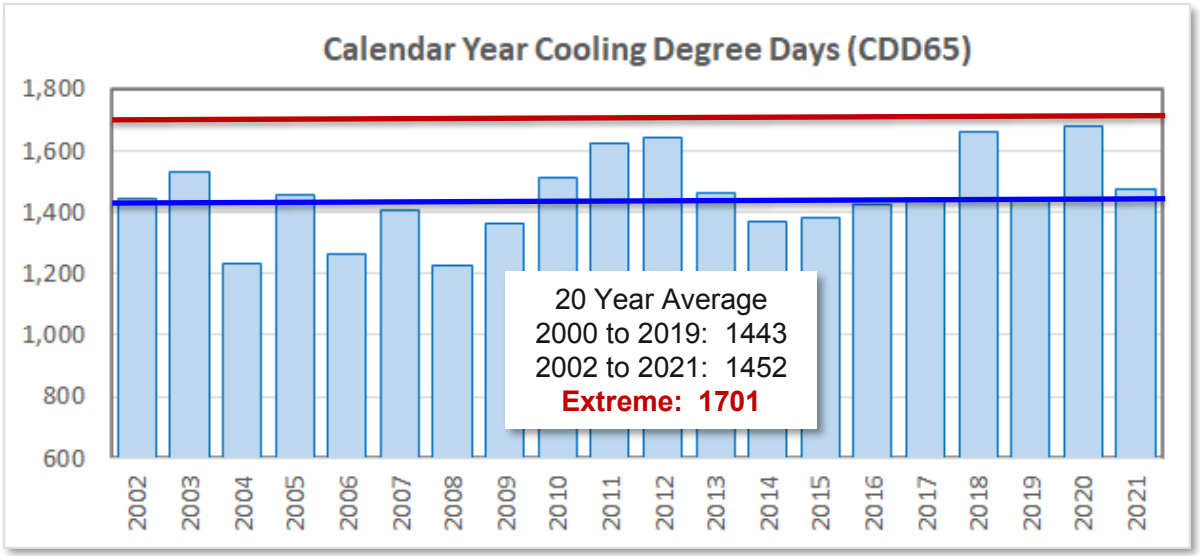
- Daily weather for hourly models
  - For each year, rank daily data by season
    - -- Hottest day to coldest day
  - Base/Normal = Average for each rank
    - -- Thick black line in the chart
    - -- Typical Hottest day: 85.8
    - -- Typical Coldest day: 20.4
  - Extreme = 1 in 10 weather
    - -- Thick red line is Extreme hot weather
    - -- Thick blue line is Extreme cold weather
    - -- Computed as average of 2 in 20
    - -- Hottest day: 88.4
    - -- Coldest day: 8.2
  - Assign base and extreme daily weather to a consistent daily pattern to use in hourly forecast models

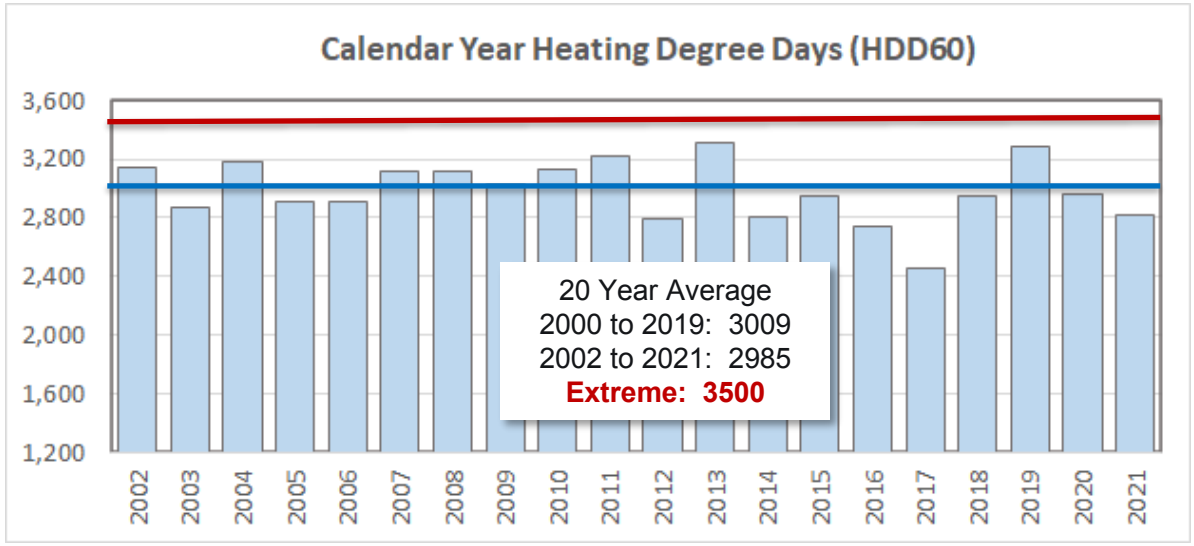


Normal Monthly Weather

- Normal Weather: 20-year normal
  - Compute daily average temperature
  - Compute daily CD (base 55, 60, 65, 70, 75)
  - Compute daily HD (base 60, 55, 50, 45)
  - Average by date for energy forecast
    -- Avg Jan 1 values, Jan 2 values, …
  - Results in a “smooth normal pattern”
  - Monthly HDD, CDD computed from daily







WEATHER RESPONSE MODELING

Weather Response Analysis

- Load Research data provide hourly and daily use estimates for a statistical sample
- Daily use shows a strong response to daily weather
- Response of load to weather is non linear
- Load research data are used to calculate HD and CD weights
  - Daily regression models
  - Y is daily sales per customer
  - X variables are daily CD and HD values
  - Calculate weights for low, medium, and high-powered degrees

Residential Weights

Spline	Wgt
HD60	0.285
HD55	0.422
HD45	0.293
CD60	0.188
CD65	0.286
CD70	0.526

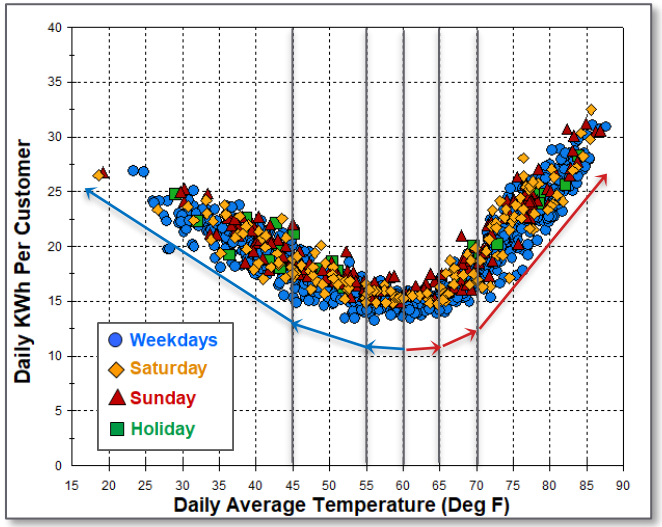
Small Power Weights

Spline	Wgt
HD55	0.572
HD45	0.428
CD55	0.237
CD65	0.629
CD75	0.134

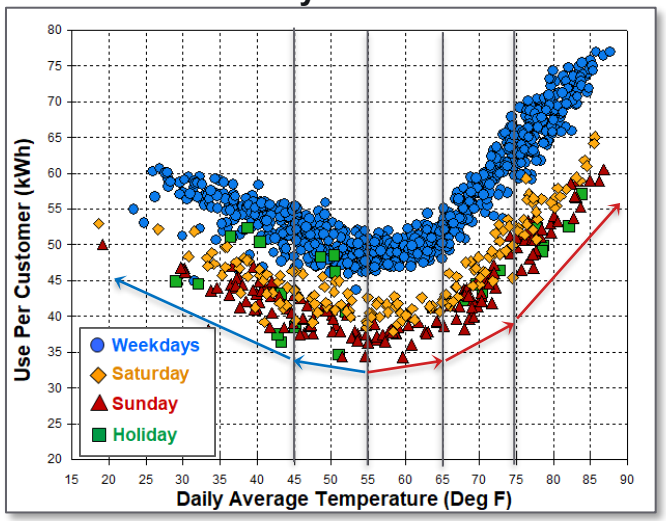
General Power Weights

Spline	Wgt
HD55	0.307
HD45	0.693
CD55	0.448
CD65	0.552

Residential Daily Sales Per Customer



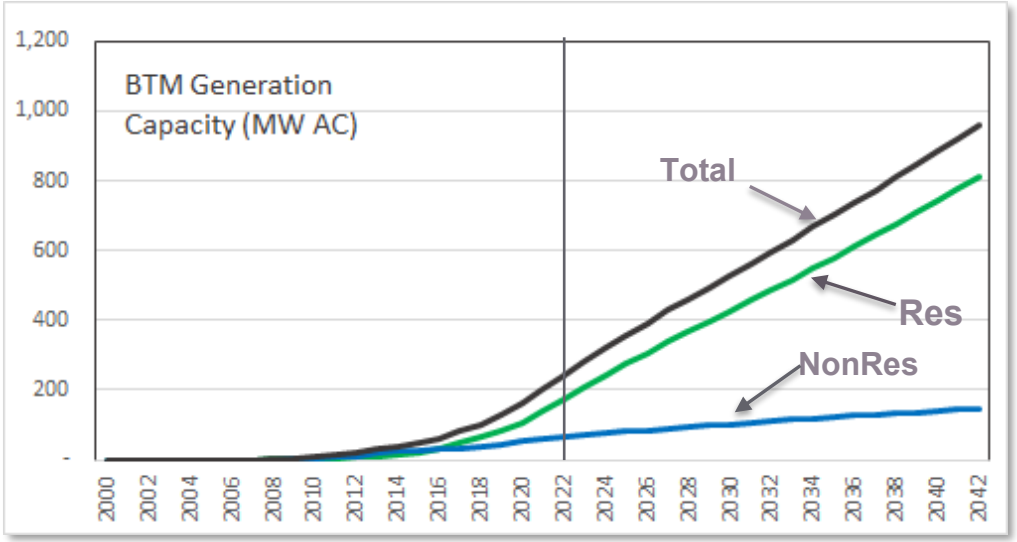
Small Power Daily Sales Per Customer

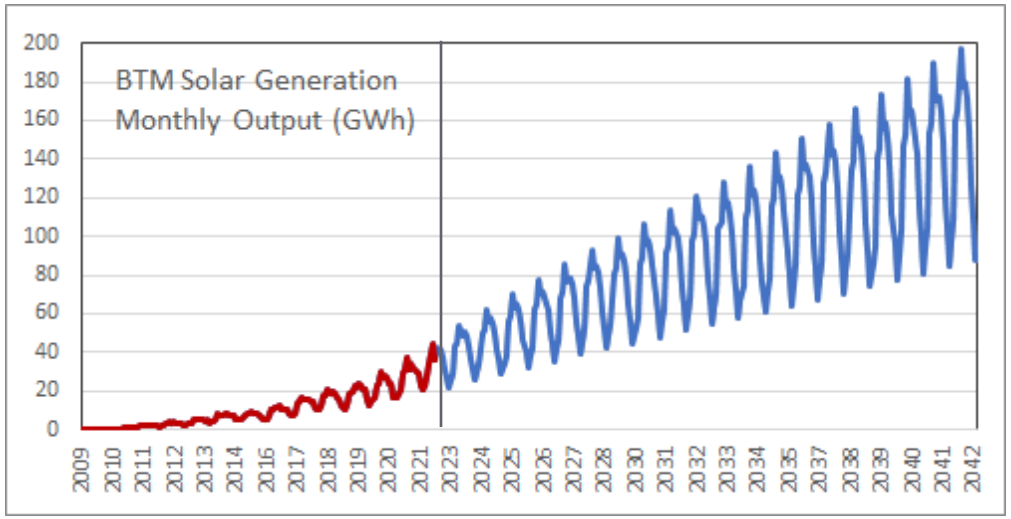


Behind the Meter (BTM) Solar Data and Forecasts

Behind the Meter (BTM) Solar Capacity and Generation

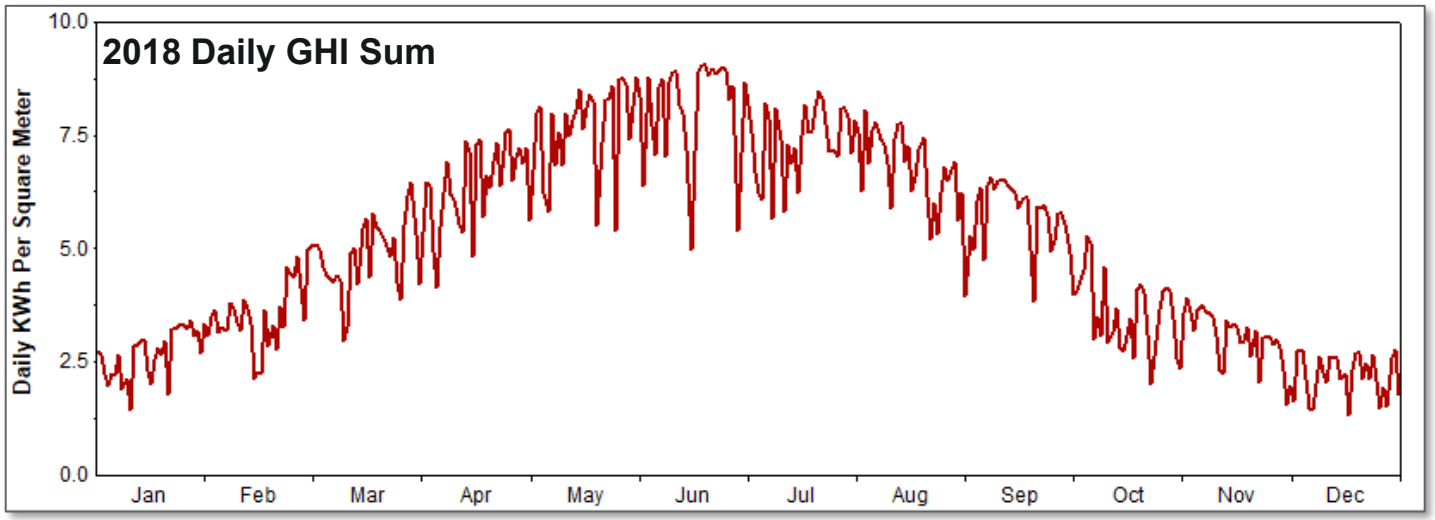
- Solar Generation Capacity (KW)
  - Output capacity (AC) for new systems in KW
  - Aggregated by month (Res & NonRes)
  - Forecasted through 2042
- Solar Generation Data (KWh)
  - All solar customers have generation output meters
  - Data are gathered monthly on a billing-cycle basis
  - Totals are calculated by billing month and rate class
- Solar Generation Model (Daily and Hourly)
  - Y = Daily average KWh output per KW capacity
  - X = Daily average GHI Sum
  - Daily forecast allocated to hours based on hourly GHI
  - Forecasts of PV generation output
    - GWh = Capacity (KW) * KWhPerKW / 1,000,000

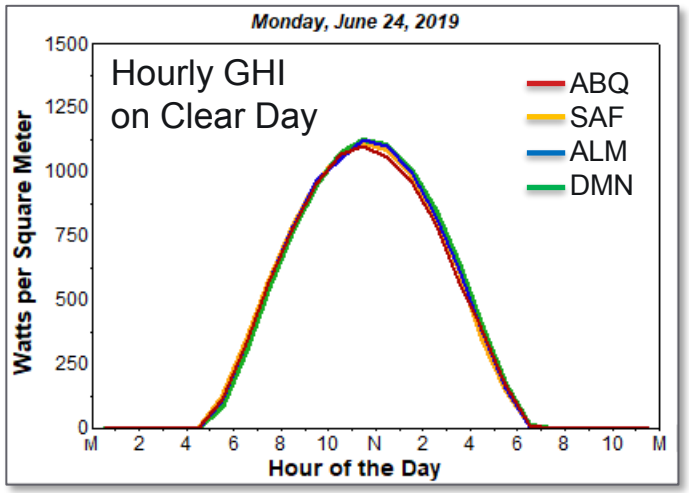


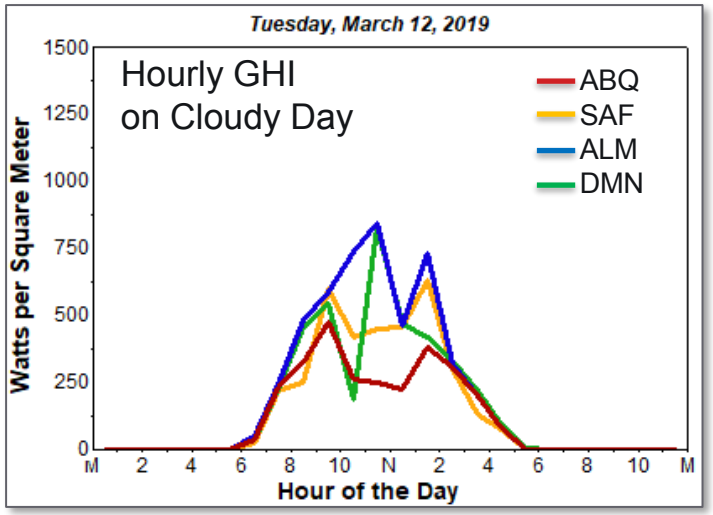


Global Horizontal Irradiation (GHI) Data

- Global Horizontal Irradiation (GHI) from AccuWeather
  - Hourly GHI data for four weather stations
  - Daily sums and monthly sums used in modeling
- 2018 pattern used for daily & hourly forecasting
  - 2018 Annual GHI within .3% of 20-year average
  - Rotated to forecast days based on daily temperature pattern
  - No change from prior IRP

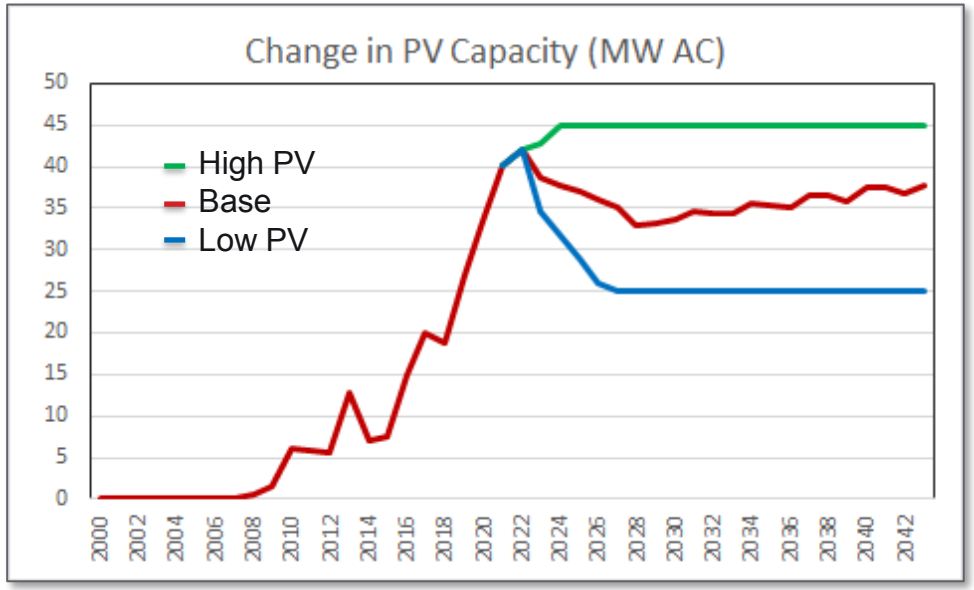


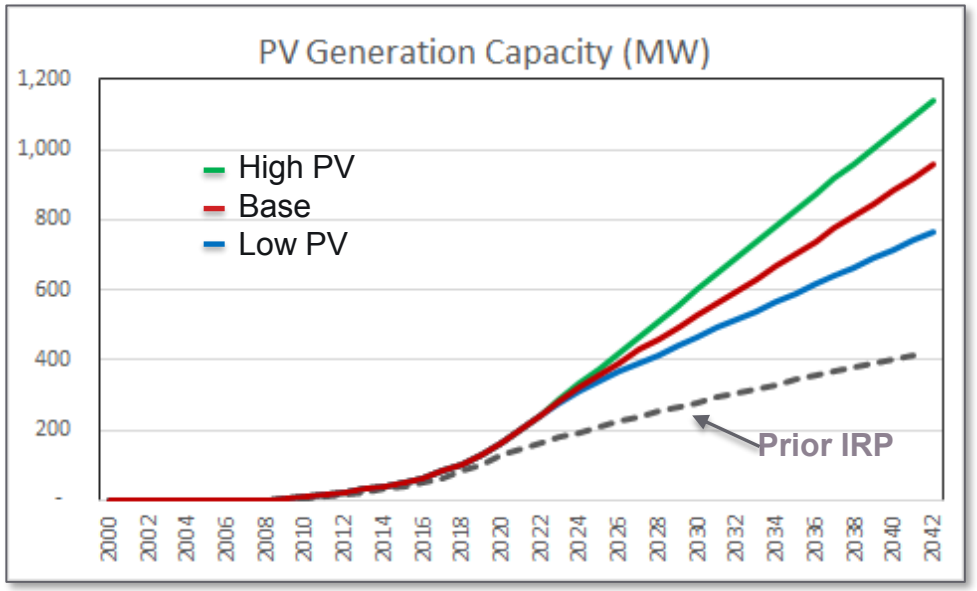




PV Scenarios

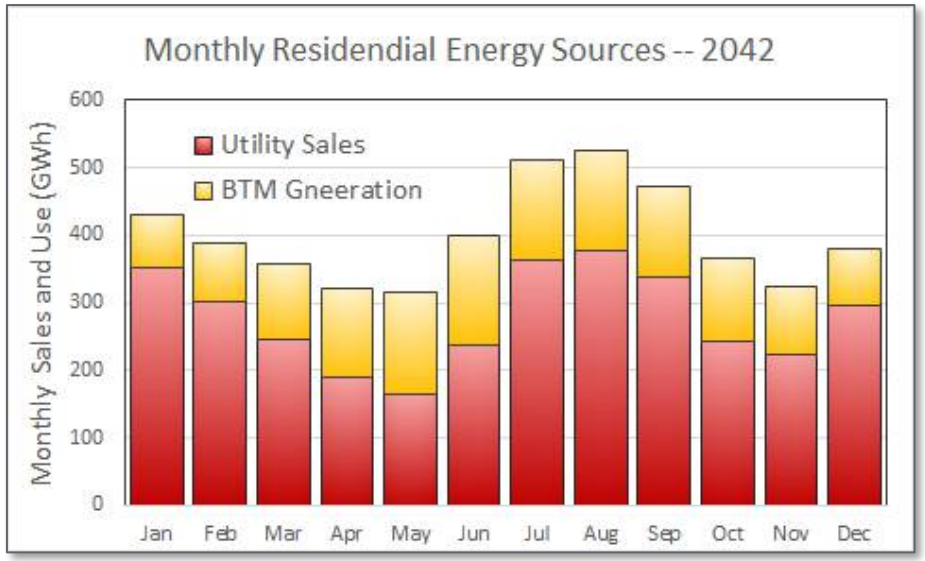
- Base Forecast is consistent with recent Annual Energy Outlook forecasts for the region assuming continuation of investment tax credits.
- 2022 Generation Capacity: 243 MW AC
- Annual PV Capacity Additions 2022 to 2040
  - High PV: 45 MW/year
  - Base PV: ~35 MW/year
  - Low PV: 25 MW/year
- 2042 Generation Capacity (MW)
  - High PV: 1,141 MW
  - Base PV: 958 MW
  - Low PV: 765 MW

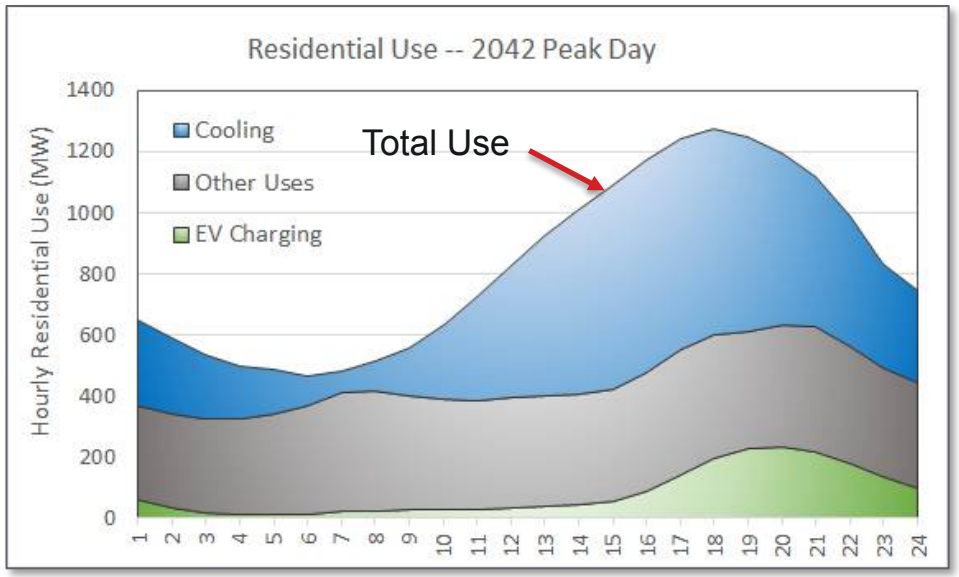


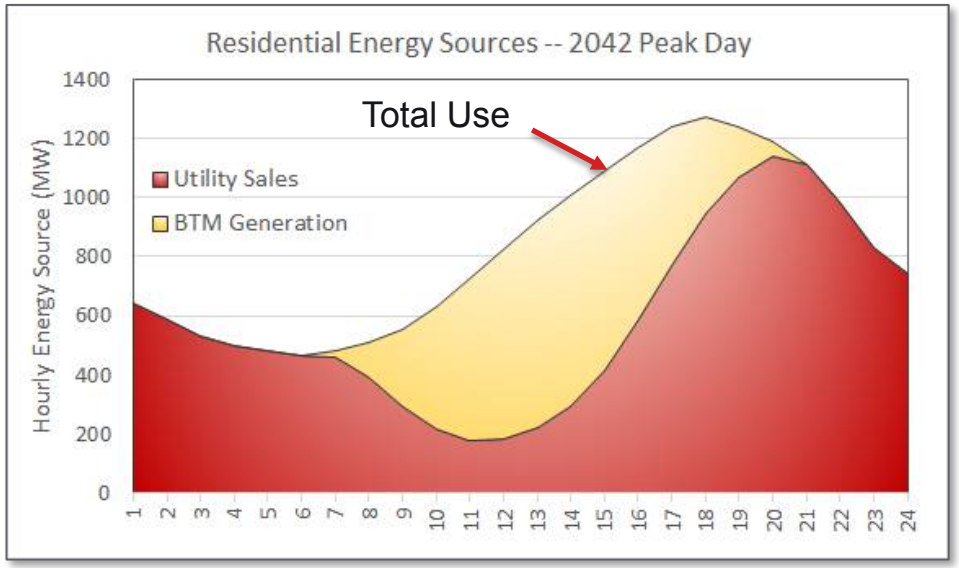


Use vs. Sales

- The presence of BTM Solar masks customer loads (end-use consumption).
- This impact is biggest for the residential class.
- Measured sales is the part of use that is supplied by utility generation.
- Models forecast customer use. Subtract generation to forecast utility sales.



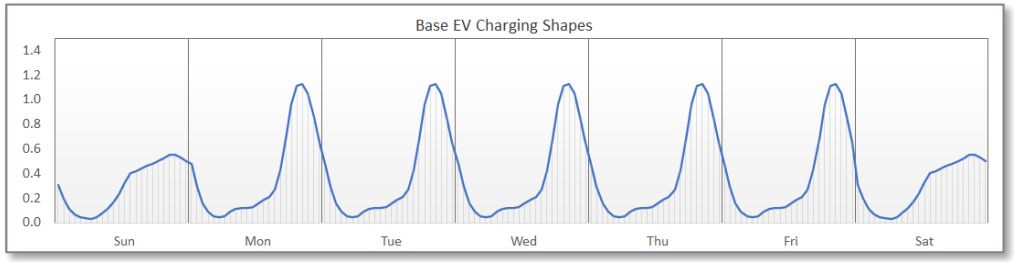


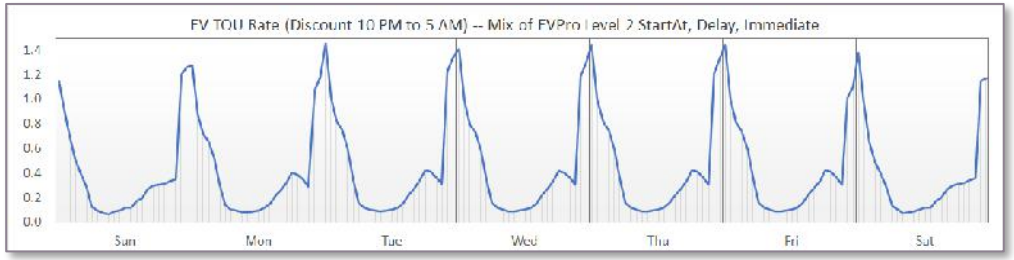


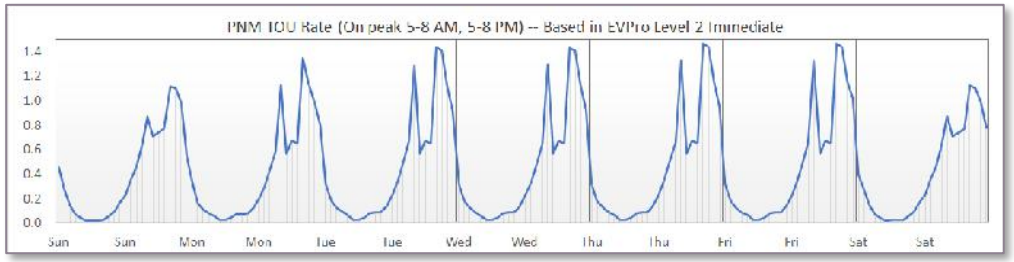
Electric Vehicle Forecast

ELECTRIC VEHICLE FORECAST

- Forecasts are based on fractions of new car sales
  - Total New Mexico annual car sales are about 87,000
  - US EV adoption forecast is the main driver
    - Rapidly increasing share of new cars (5% now, 60% by 2042)
  - NM adoption is about 41% of US adoption
  - 75% of NM adoptions are in PNM territory
  - EV annual energy use is about 4 MWh per vehicle
  - About 80% of charging is residential
- Charging profiles based on National Labs data
  - Base shape – Idaho National labs
  - TOU shapes based on NREL EV-Pro strategies
    - Scheduled Start (Start at specified time)
    - Delayed Start (Charge by specified time)
    - Immediate (Unscheduled, like base shape)

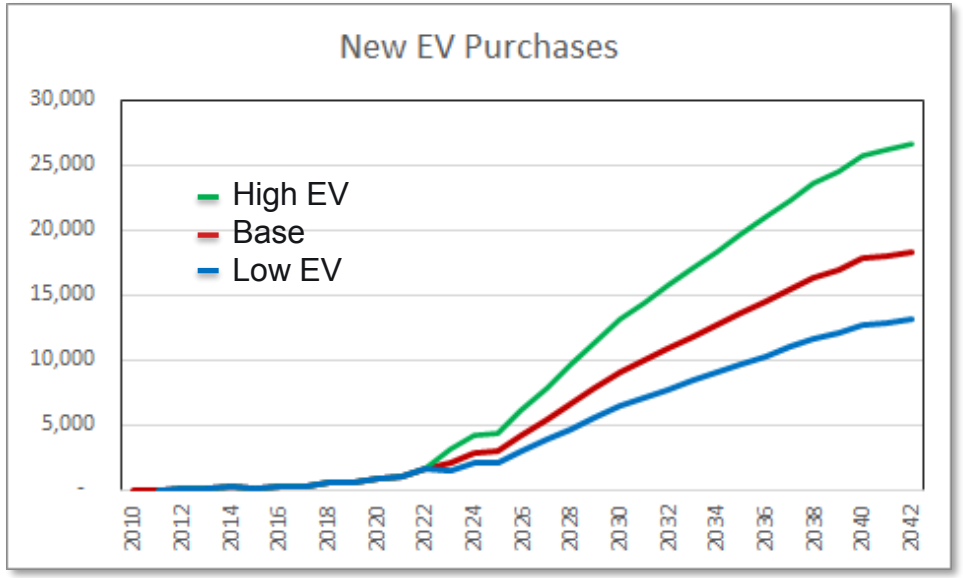


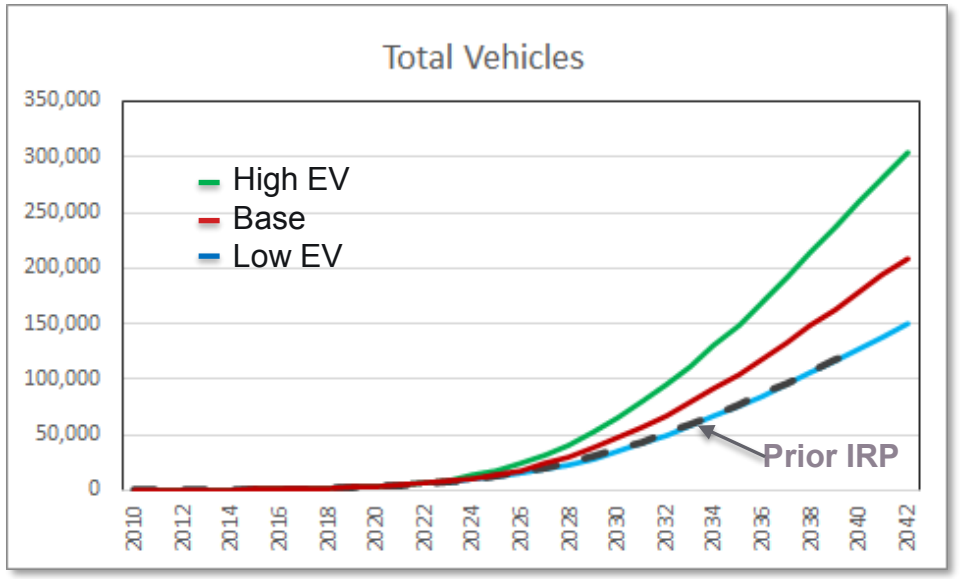




EV SCENARIOS

- Annual EV Additions 2023 to 2042
  - High EV: Grows to 27,000 by 2042
  - Base EV: Grows to 18,000 by 2042
  - Low EV: Grows to 13,000 by 2042
- 2042 Electric Vehicle Count
  - High EV: 304,000
  - Base EV: 209,000
  - Low EV: 138,000
- Higher than prior IRP forecast
  - 40% higher in 2040
  - Driven by faster US adoption forecast
  - Prior IRP similar to current Low case

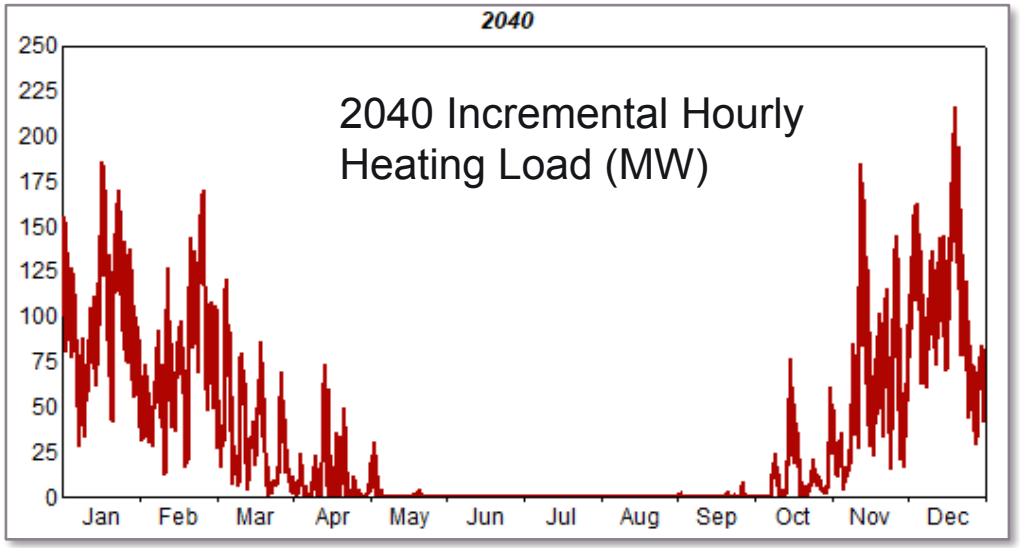


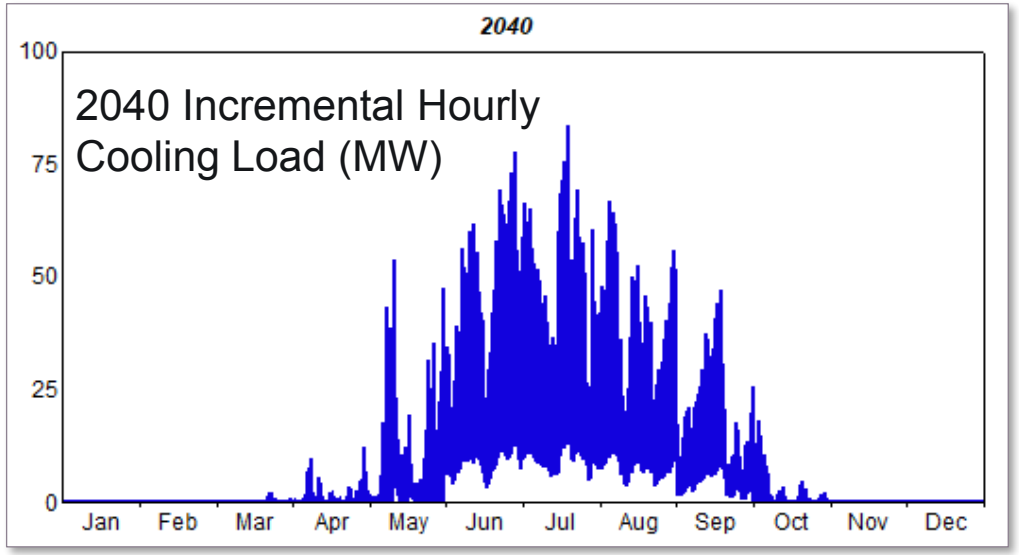


Other Scenario Inputs

Building Electrification

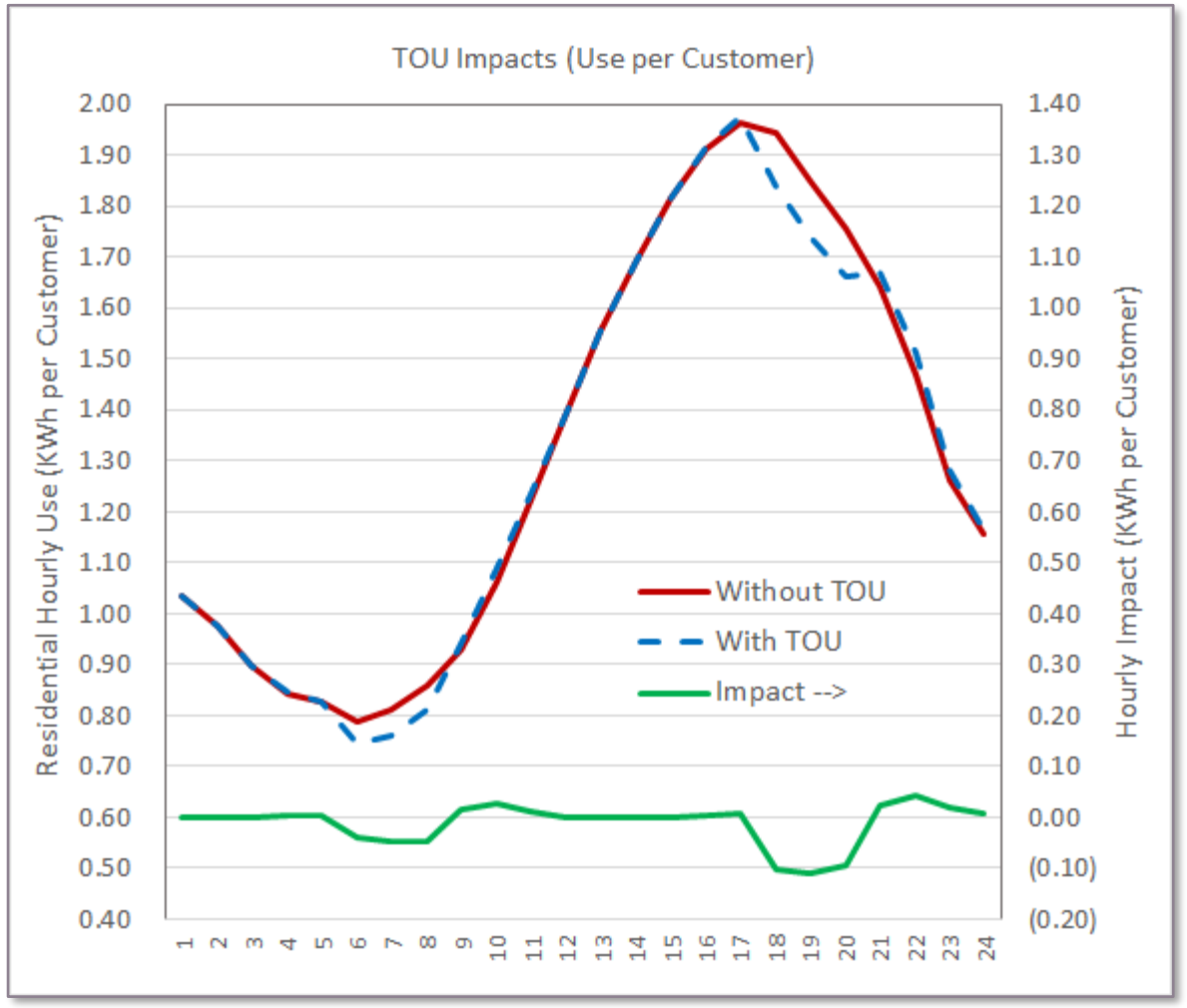
- New homes starting in 2025
  - Natural Gas and Propane not allowed
  - Electric heat share goes from 15% to 90%
  - Mostly heat pumps, 80% of the increase
  - Less evaporative cooling, more central air
- Existing homes converted to heat pumps
  - About 2% per year (7,000 homes)
  - Evaporative cooling displaced in 40% of the 2%
  - Incremental cooling UEC is 1700 KWh
- Heat pump heating UEC averages 2400 KWh
- Overall electric heating share increases:
  - 15.5% in 2020 to 45% in 2040
- Heating/Cooling shapes from load research





Residential Time of Use Rates

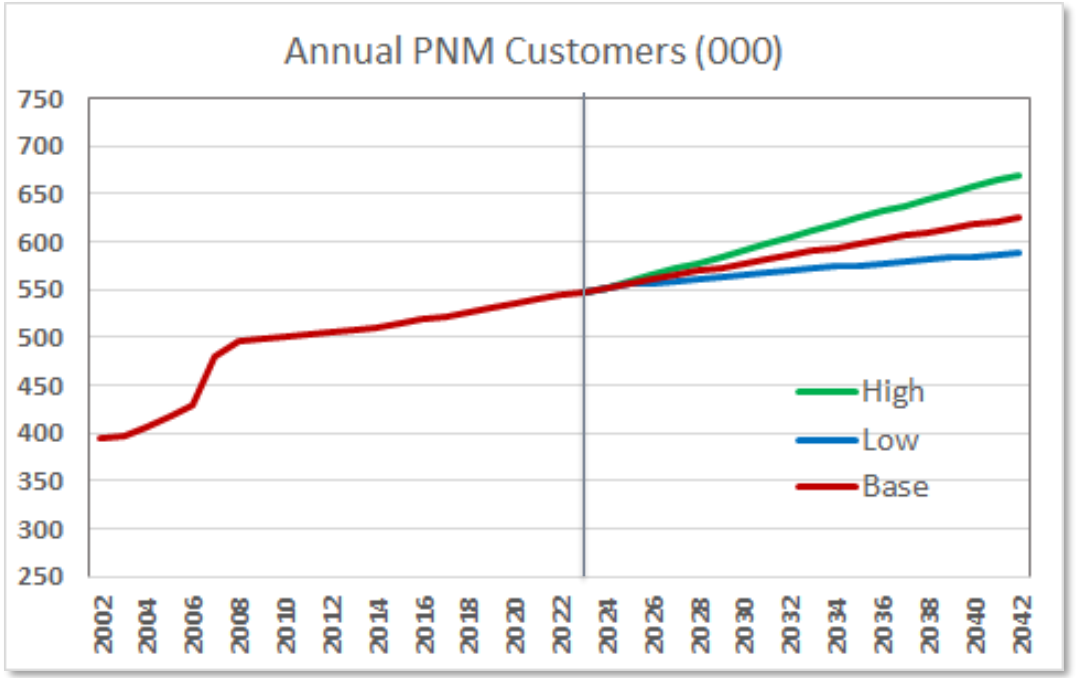
- Introduce Residential TOU in 2030
  - Pilots through 2029
  - Full Opt-out program in 2030
  - On-peak 5-8 AM, 5-8 PM.
  - Assume 20% opt out, 80% do not
  - Applies also to EV not on WHEV rate
- EV impacts modeled separately
- Energy impact levels from summary report by ACEEE of 50 pricing pilots (on/off price ratio ~ 2)
  - On-Peak reduction: 6%
  - Average energy reduction: 1%



Energy Modeling and Forecasts

PNM Customer Forecast

- Residential trend model through 2024
  - Population elasticity model after 2024
- Small Power trend model through 2024
  - Pop/Emp elasticity model after 2024
- Regression model for General Power (GP)
  - Population and Non-Manufacturing Employment
- Elasticity model for Large Power (LP4)
  - Non-Manufacturing Employment
- Manual Adjustment for Industrial Loads
  - LP4 addition in 2023
  - LS30 expansion in 2022 to 2024
- Scenarios reflect High/Low Economics
- Very little change from prior IRP

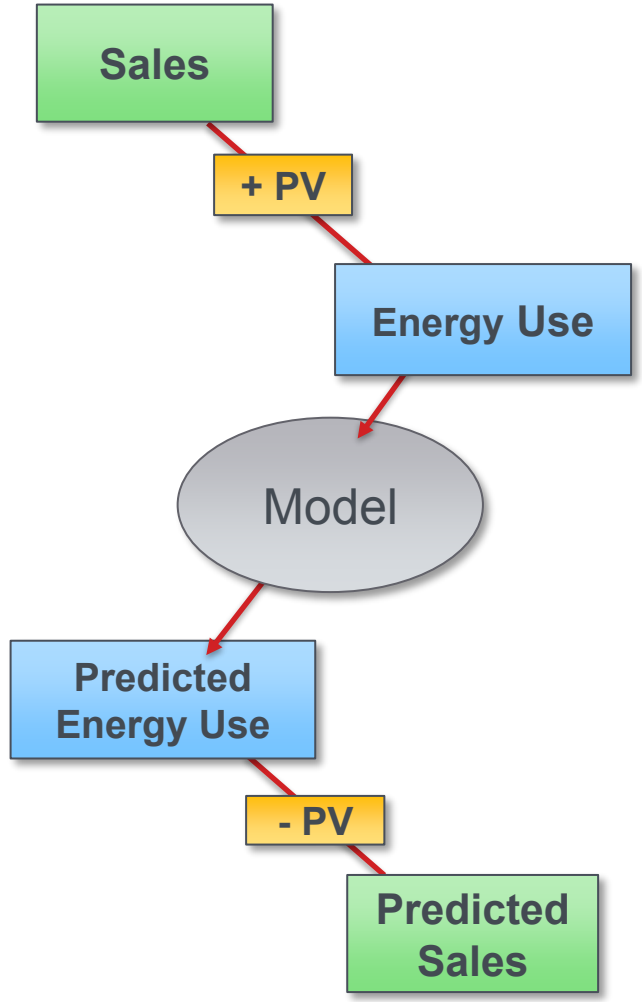


Range	Average Annual Customer Gain				
	Res	SP	GP	LP	Total
2012-2022	3,449.4	382.6	-12.8	-6.6	3,810.2
2022-2032	3,814.5	411.4	10.7	0.2	4,236.6
2032-2042	3,580.4	385.7	9.5	0.3	3,975.9
Range	Average Annual Growth Rate				
	Res	SP	GP	LP	Total
2012-2022	0.74%	0.73%	-0.30%	-3.23%	0.73%
2022-2032	0.76%	0.73%	0.26%	0.10%	0.75%
2032-2042	0.67%	0.64%	0.22%	0.17%	0.66%

*Total excludes lighting classes

Energy Use and Energy Sales

- Same approach as in prior IRP
- Monthly sales and monthly energy use:
  - Sales = net delivery of energy through the customer meter
  - Energy use = consumption of appliances and equipment
  - Energy use is bigger than sales because of PV generation
  - Models explain energy use
- Monthly Use Models
  - Regression models
  - Y is energy use per customer (UPC)
  - X variables are end-use drivers and weighted CD and HD variables
- PNM Sales and Load
  - Sales computed as Energy Use – PV Generation

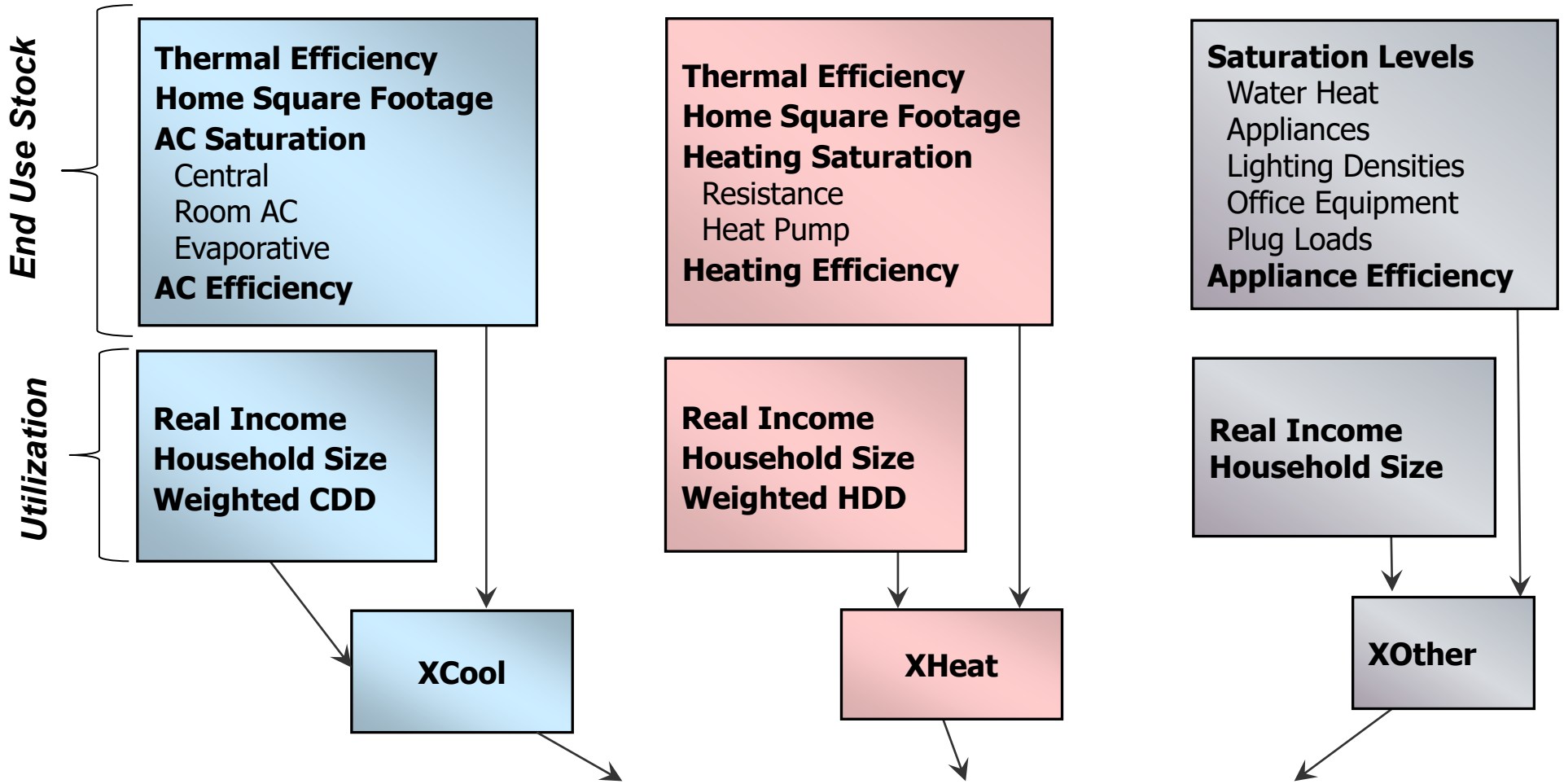


Statistically Adjusted End-Use Framework

- Residential and commercial models use Statistically Adjusted End-Use (SAE) Model
- SAE models account for:
  - Appliance saturation and equipment density
  - Appliance and equipment efficiency
  - Thermal efficiency of buildings
- Efficiency and saturation data initialized using 2021 EIA data for Mountain region
- Saturation and intensity values are modified to agree with PNM data
  - Base-year intensities and saturations from PNM Efficiency Potential Study
- Residential framework is shown on the next slide
- Commercial framework is similar (applied to SP, GP, LP4)

Residential SAE Modeling Framework

SAE = Statistically Adjusted End-Use

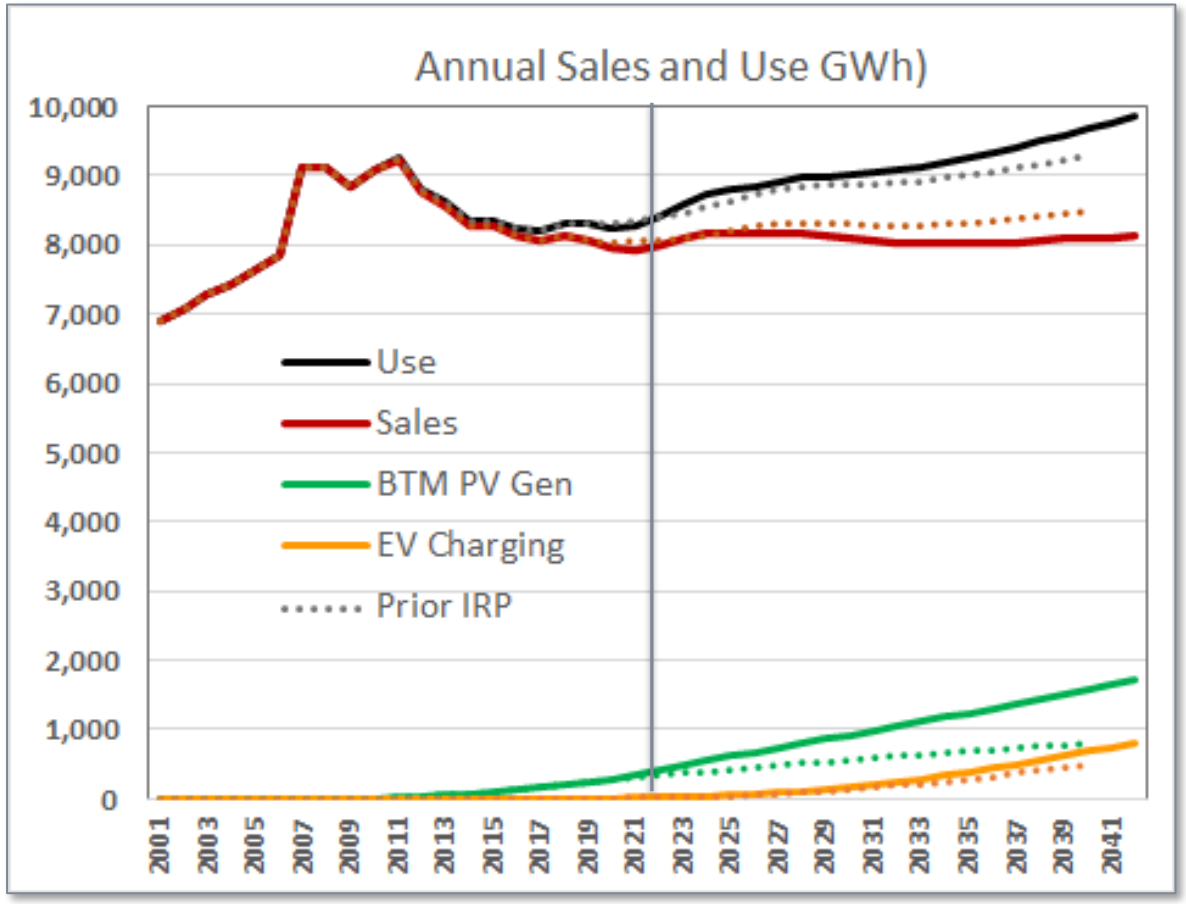


$$\text{Sales}_m + \text{PVGen}_m = a + b_c \times \text{XCool}_m + b_h \times \text{XHeat}_m + b_o \times \text{XOther}_m + e_m$$

Energy Forecast Summary

Year	Customers	Sales (GWh)	EV Sales (GWh)	PV Output (GWh)
2012	505,407	8,560.3	0.4	37.5
2017	521,850	8,129.0	4.9	158.8
2022	543,509	8,105.1	21.5	410.5
2027	564,851	8,160.3	85.3	744.6
2032	585,874	8,018.0	250.6	1,055.1
2037	606,132	8,060.7	503.6	1,372.8
2042	625,633	8,152.7	809.1	1,707.8

Year Range	Customers AGR	Sales AGR	Year	EV % of Sales	PV % of Sales
			2010	0.00%	0.44%
2012 to 2017	0.64%	-1.03%	2015	0.06%	1.95%
2017 to 2022	0.82%	-0.06%	2020	0.26%	5.06%
2022 to 2027	0.77%	0.14%	2025	1.04%	9.12%
2027 to 2032	0.73%	-0.35%	2030	3.13%	13.16%
2032 to 2037	0.68%	0.11%	2035	6.25%	17.03%
2037 to 2042	0.64%	0.23%	2040	9.92%	20.95%

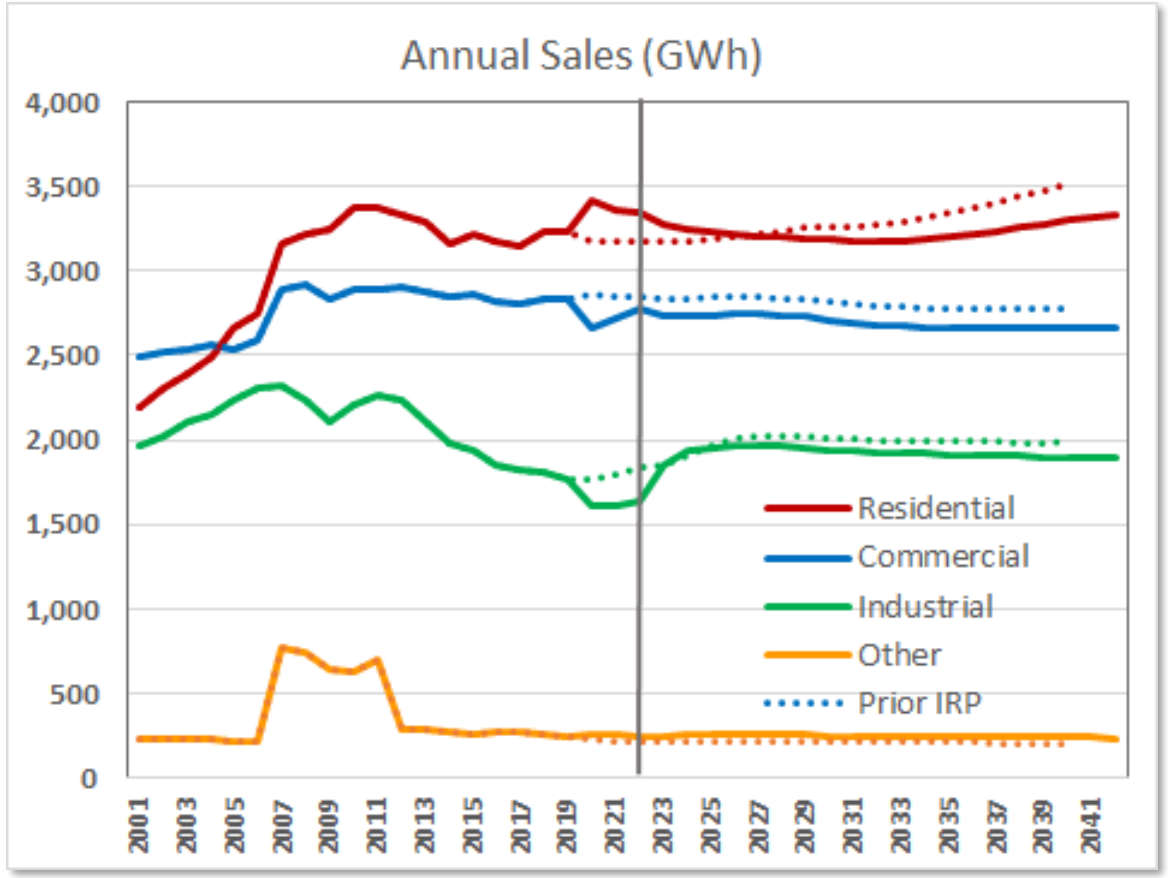


Excludes LS36B and incremental economic development loads

Energy Sales Forecast by Customer Class

Energy Sales in GWh					
Year	Residential	Commercial	Industrial	Other	Total
2012	3,295	2,880	2,103	282.5	8,560
2017	3,233	2,830	1,805	261.5	8,129
2022	3,271	2,737	1,849	248.9	8,105
2027	3,206	2,740	1,960	254.0	8,160
2032	3,177	2,672	1,922	247.3	8,018
2037	3,257	2,660	1,903	241.7	8,061
2042	3,348	2,674	1,894	236.6	8,153

Annual Growth Rate for Energy Sales					
Year Range	Residential	Commercia	Industrial	Other	Total
2012 to 2017	-0.37%	-0.35%	-3.02%	-1.54%	-1.03%
2017 to 2022	0.23%	-0.66%	0.48%	-0.98%	-0.06%
2022 to 2027	-0.40%	0.02%	1.18%	0.40%	0.14%
2027 to 2032	-0.18%	-0.50%	-0.40%	-0.53%	-0.35%
2032 to 2037	0.50%	-0.09%	-0.20%	-0.46%	0.11%
2037 to 2042	0.55%	0.11%	-0.09%	-0.42%	0.23%

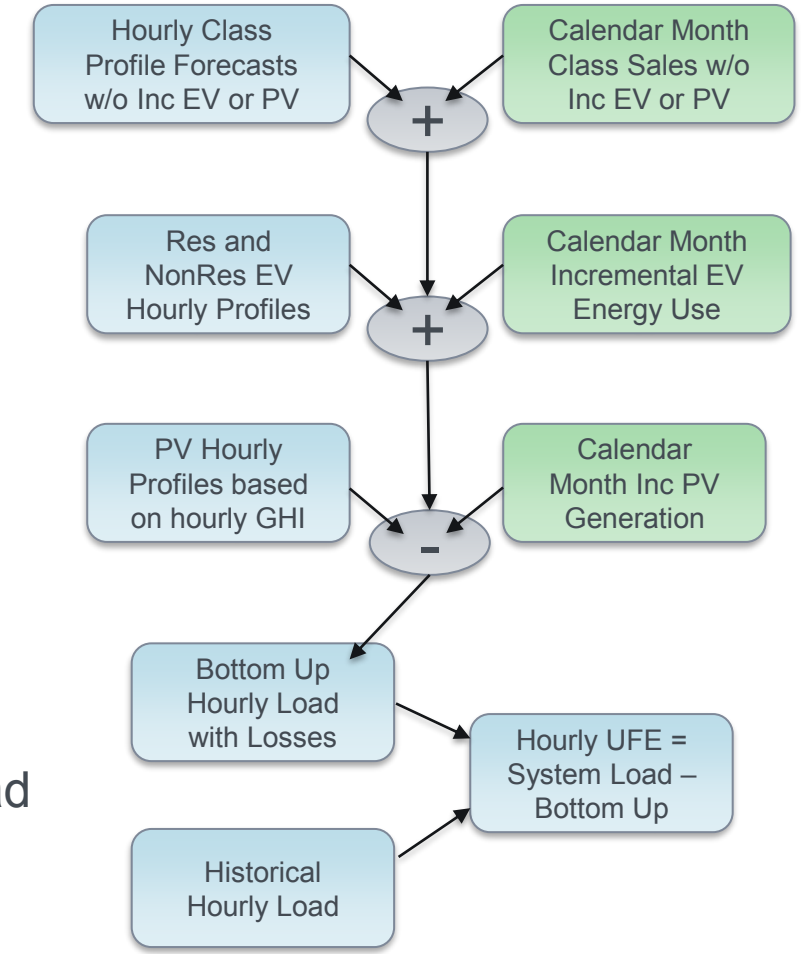


Commercial is Small Power + General Power
Industrial is Large Power + Large Service
Other is Irrigation, Water, and Lighting
Industrial excludes LS30B and incremental economic development loads

Hourly Load and Peak Demand Forecast

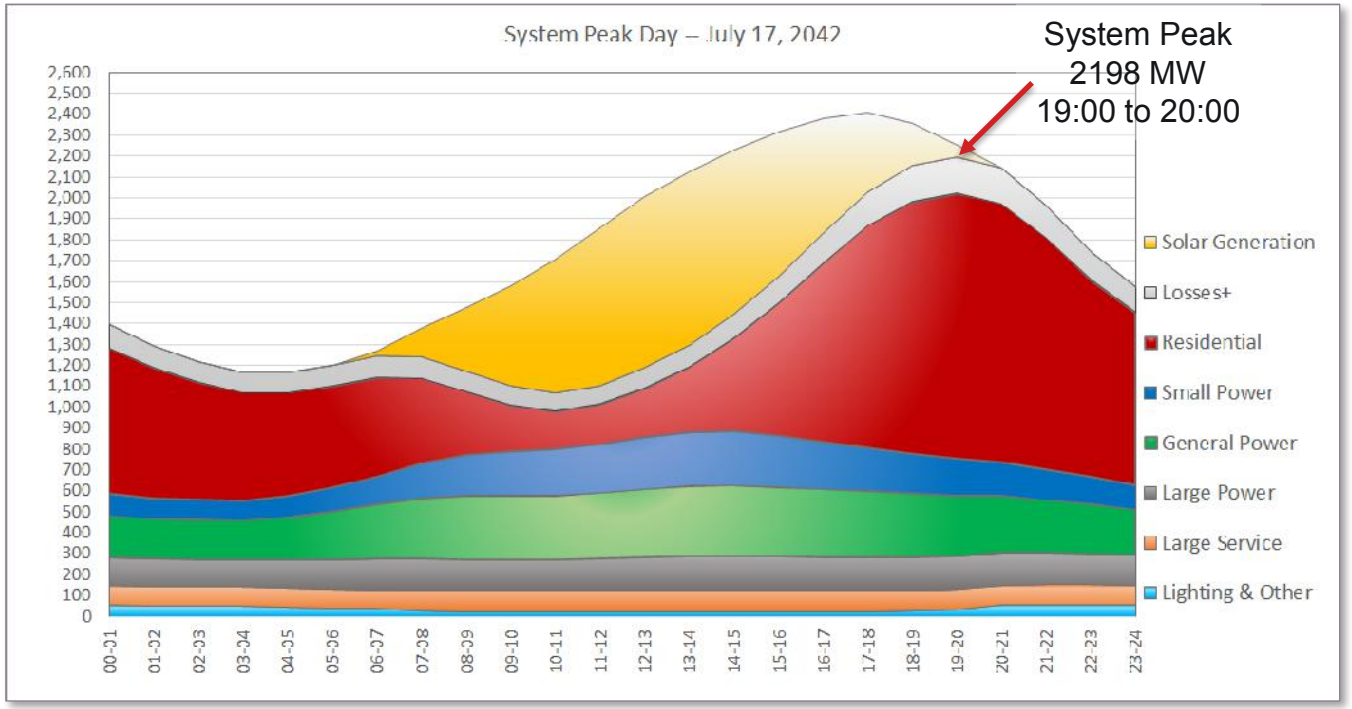
Hourly Load and Peak Load Forecasts

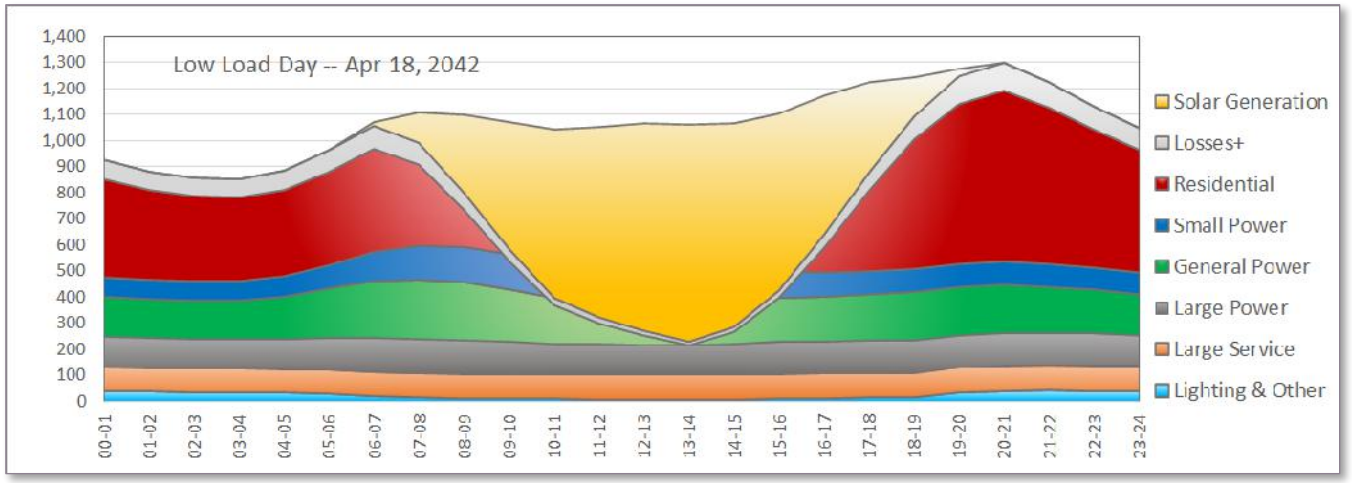
- Hourly load models for each class
  - Estimated with hourly load research data for 2015 to 6/2022
  - Forecasted using normal daily weather pattern
- Hourly shapes for EV and PV
  - EV shapes: Idaho National Labs, NREL EV Pro
  - PV shapes based on hourly GHI data
- Bottom-up logic
  - Calendar month sales forecast without incremental EV or PV
  - Calibrate class hourly profile to calendar month energy value
  - Scale EV profile to incremental EV energy, add to class load
  - Scale PV profile to incremental PV energy, subtract from class load
  - Multiply by annual loss factor based on voltage level
  - Add across classes
- Compute and apply UFE adjustment factors by month and hour



Hourly Loads

- Bottom-up process depiction
  - Class loads are at the meter
  - Excludes rate class LS36 and post 2024 economic development loads
  - Loss estimate based on loss factors by delivery voltage
  - Includes allocation of UFE
- Solar is total BTM generation at the customer meter



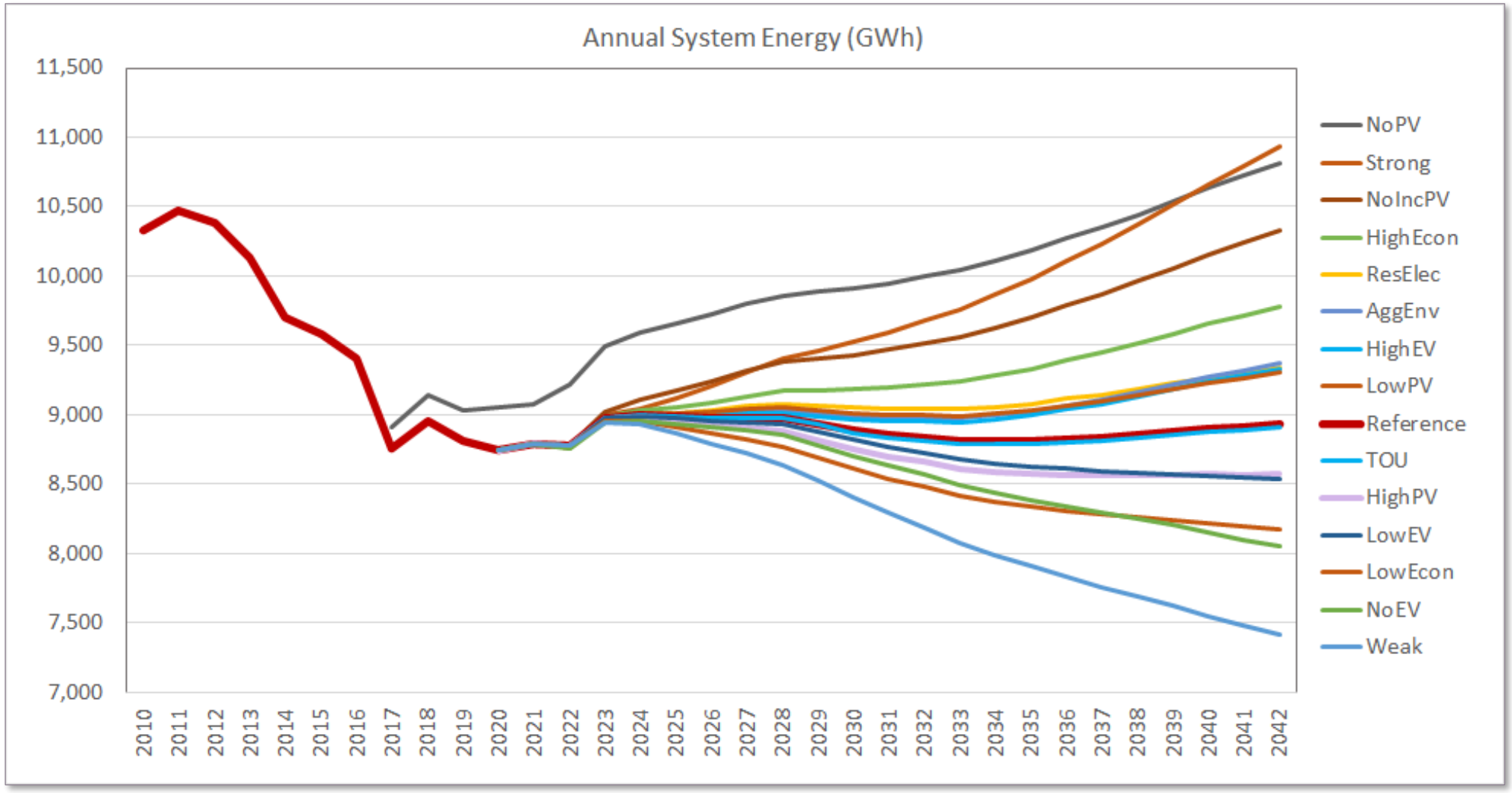


Forecast Scenarios

Scenario Definitions

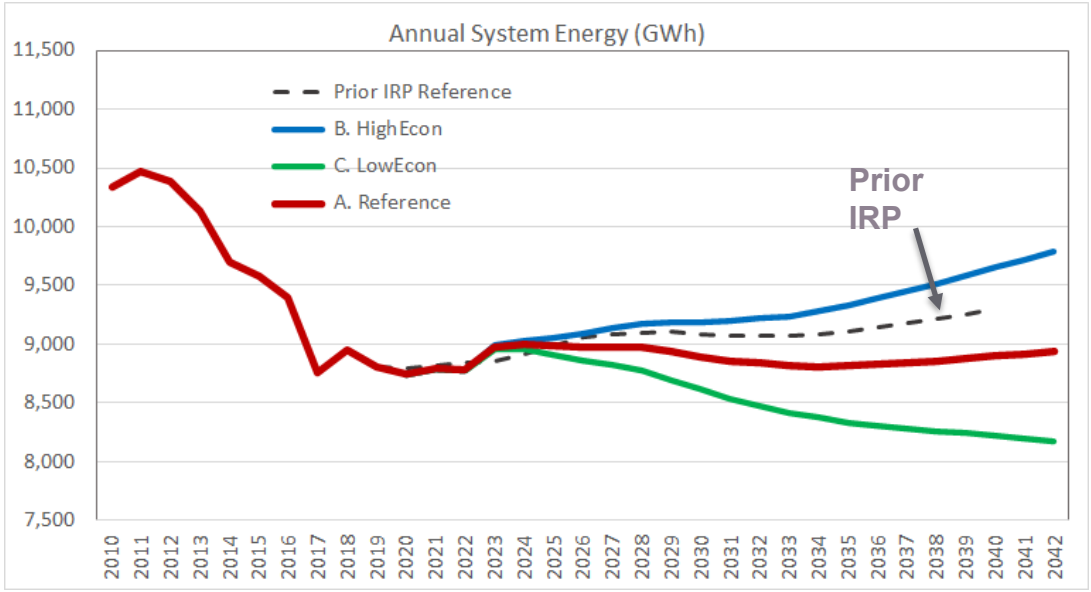
	Scenario	Economic Forecast	BTM PV	EV Adoption	Building Electrification	TOU	Weather	Description
A	Reference Forecast	Mid	Mid	Mid	Mid	No	Normal	**Base Forecast**
B	High Economics	**High**	Mid	Mid	Mid	No	Normal	Strong Econ, Misc. End Use
C	Low Economics	**Low**	Mid	Mid	Mid	No	Normal	Weak Econ, Misc End Use
D	Strong Energy Growth	**High**	LowPV	**High**	**High**	No	Normal	Strong Econ, Misc End Use,` Weak PV, Strong EV, Add Res Electrification
E	Weak Energy Growth	**Low**	HighPV	**Low**	Mid	No	Normal	Weak Econ, Misc End Use Strong PV, Weak EV
F	High BTM PV	Mid	**HighPV**	Mid	Mid	No	Normal	Strong PV
G	Low BTM PV	Mid	**LowPV**	Mid	Mid	Mid	Normal	Weak PV
H	Zero Incremental PV	Mid	**Zero Inc PV**	Mid	Mid	Mid	Normal	Zero Incremental PV
I	Zero PV	Mid	**Zero PV**	Mid	Mid	No	Normal	No PV Ever
J	High EV Adoption	Mid	Mid	**High**	Mid	No	Normal	Strong EV
K	Low EV Adoption	Mid	Mid	**Low**	Mid	No	Normal	Weak EV
L	Aggressive Environmental Regulation	Mid	**HighPV**	**High**	**High**	No	Normal	Strong PV, Strong EV, **Add Res Electrification**
M	High Building Electrification	Mid	Mid	Mid	**High**	No	Normal	**Add Res Electrification**
N	TOU Pricing	Mid	Mid	Mid	Mid	**Yes**	Normal	**Add TOU Impacts**
O	Extreme Weather Scenario	Mid	Mid	Mid	Mid	No	Extreme	Repeat Base case with Extreme weather. Hot summer, Cold winter, Incorpoate weather trend

Annual System Energy Scenarios

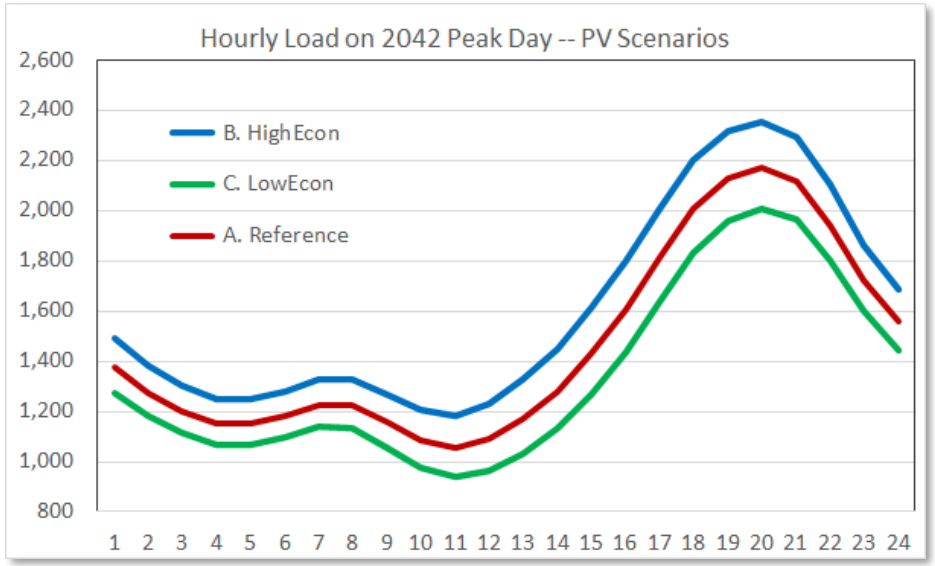


Growth Scenarios

- Reference Case
- High Economic Growth
  - High Population, Employment, Income
  - High Miscellaneous end-use growth
- Low Economic Growth
  - Low Population, Employment, Income
  - Low Miscellaneous end-use growth

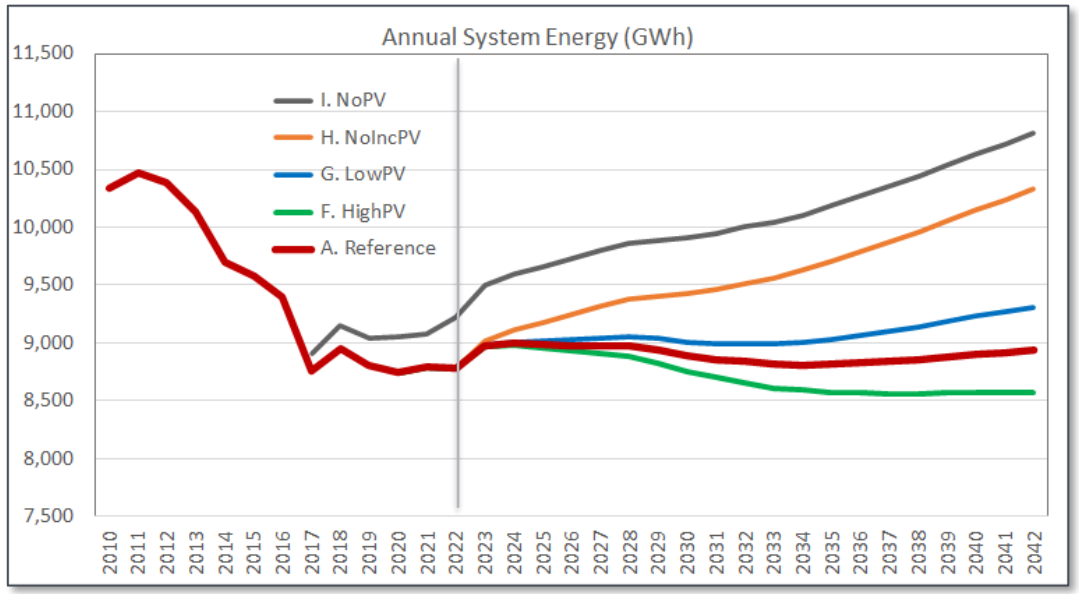


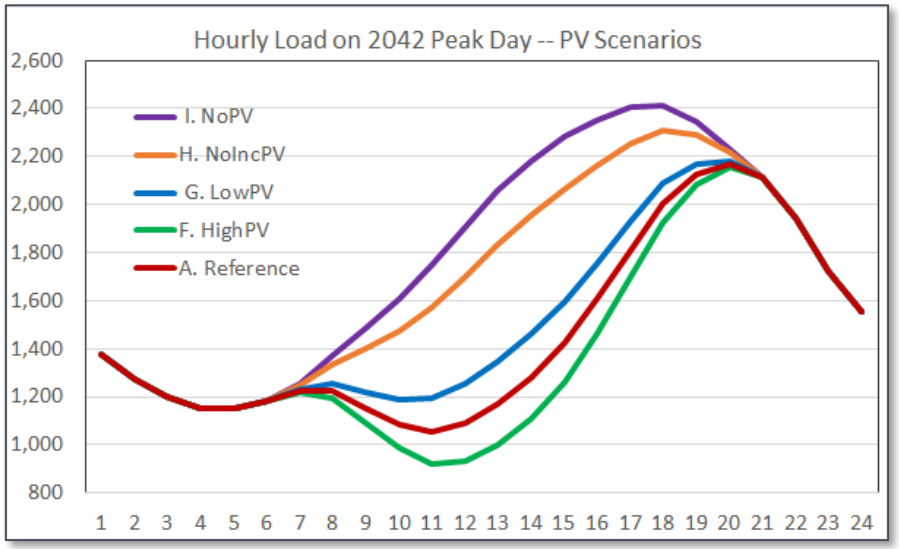
Year	Annual System Energy (GWh)			Annual Peak (MW)		
	Base	High Econ	Low Econ	Base	High Econ	Low Econ
2022	8,777	8,777	8,777	1,961	1,961	1,961
2027	8,978	9,132	8,820	1,898	1,932	1,865
2032	8,838	9,218	8,480	1,933	2,017	1,856
2037	8,839	9,449	8,281	2,033	2,164	1,915
2042	8,934	9,785	8,176	2,169	2,353	2,006



Behind the Meter PV Scenarios

- PV Capacity in 2042
  - Base – 1,141 MW
  - High – 958 MW
  - Low – 765 MW
  - No Incremental – 243 MW (same as 2022)
- Peak Hour
  - Without PV, hour ending 18 (5 pm to 6 pm)
  - With PV, hour ending 20 (7 pm to 8 pm)

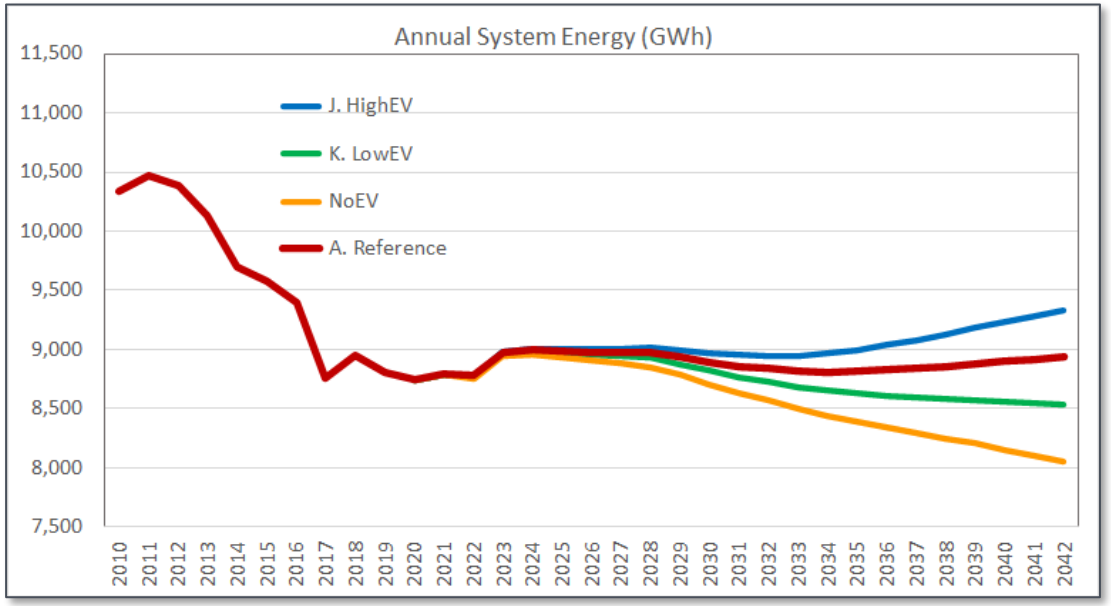




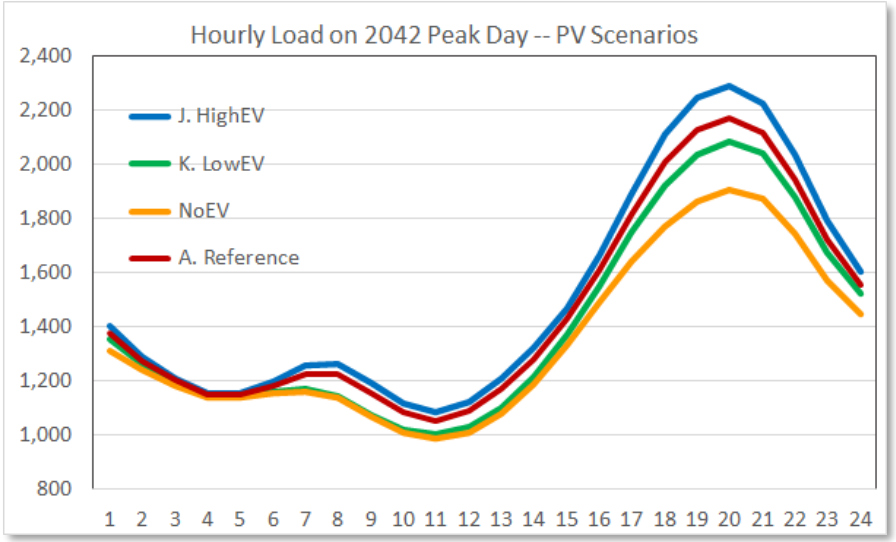
Year	Annual System Energy (GWh)					Annual Peak (MW)				
	Base	High PV	Low PV	NoIncPV	No PV	Base	High PV	Low PV	NoIncPV	No PV
2022	8,777	8,777	8,777	8,777	9,218	1,961	1,961	1,961	1,961	2,087
2027	8,978	8,910	9,044	9,315	9,796	1,898	1,883	1,913	1,975	2,127
2032	8,838	8,659	8,994	9,517	10,000	1,933	1,918	1,951	2,052	2,193
2037	8,839	8,561	9,097	9,870	10,351	2,033	2,023	2,046	2,168	2,288
2042	8,934	8,573	9,310	10,335	10,816	2,169	2,157	2,182	2,310	2,415

Electric Vehicle Scenarios

- The Reference forecast includes base levels of EV adoption. In the three scenarios, the number of vehicles in 2042 are as follows:
  - High PV: 304,000
  - Base PV: 209,000
  - Low PV: 150,000
- Annual sales and peak results are summarized below

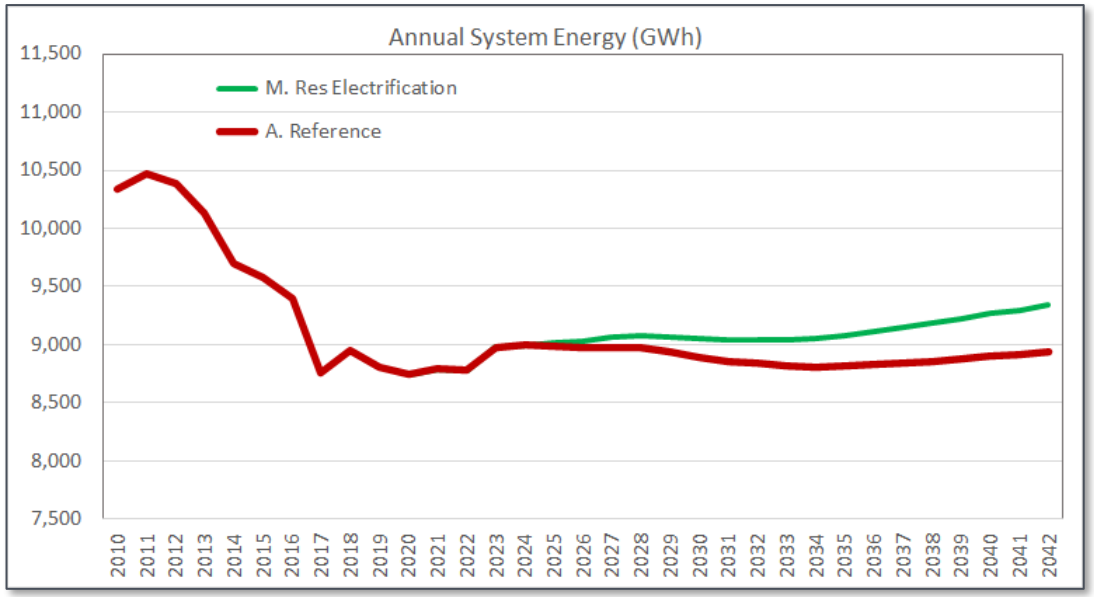


Year	Annual System Energy (GWh)				Annual Peak (MW)			
	Base	High EV	Low EV	No EV	Base	High EV	Low EV	No EV
2022	8,777	8,777	8,777	8,754	1,961	1,961	1,961	1,956
2027	8,978	9,007	8,947	8,885	1,898	1,906	1,892	1,873
2032	8,838	8,950	8,725	8,566	1,933	1,967	1,907	1,850
2037	8,839	9,079	8,595	8,292	2,033	2,105	1,980	1,869
2042	8,934	9,329	8,532	8,055	2,169	2,287	2,082	1,906

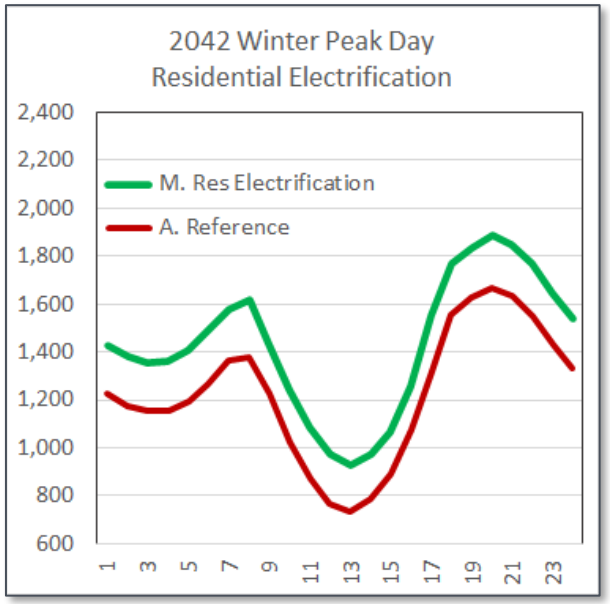


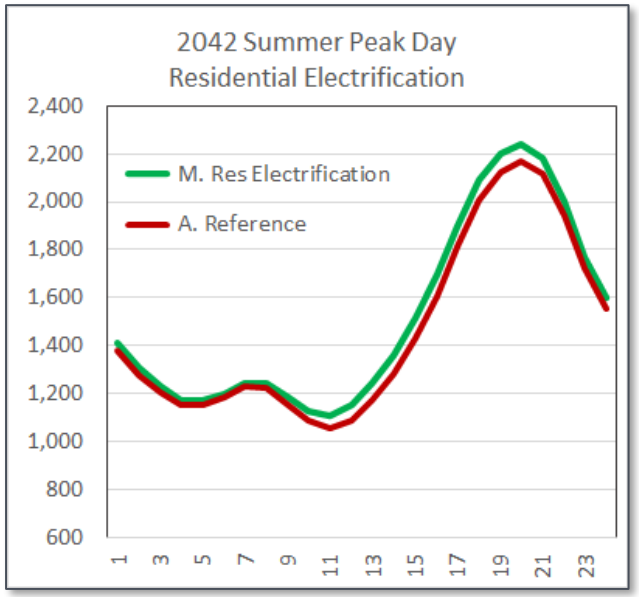
Residential Electrification

- Residential Electrification Scenario
  - Gas/Propane not allowed in new homes
  - Conversion incentives for existing homes
  - Electric heat share rises from 15% to 45%
  - Increased cooling loads as heat pumps replace evaporative cooling



Year	Annual System Energy (GWh)		Annual Peak (MW)	
	Base	Building Electrification	Base	Building Electrification
2022	8,777	8,777	1,961	1,961
2027	8,978	9,060	1,898	1,914
2032	8,838	9,043	1,933	1,972
2037	8,839	9,147	2,033	2,087
2042	8,934	9,339	2,169	2,240

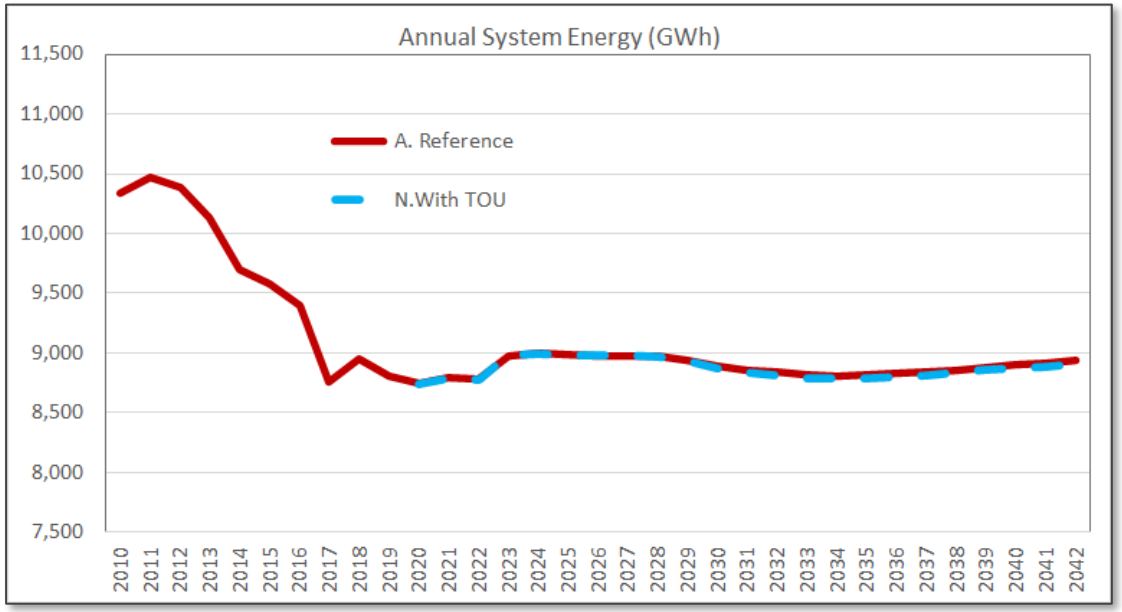


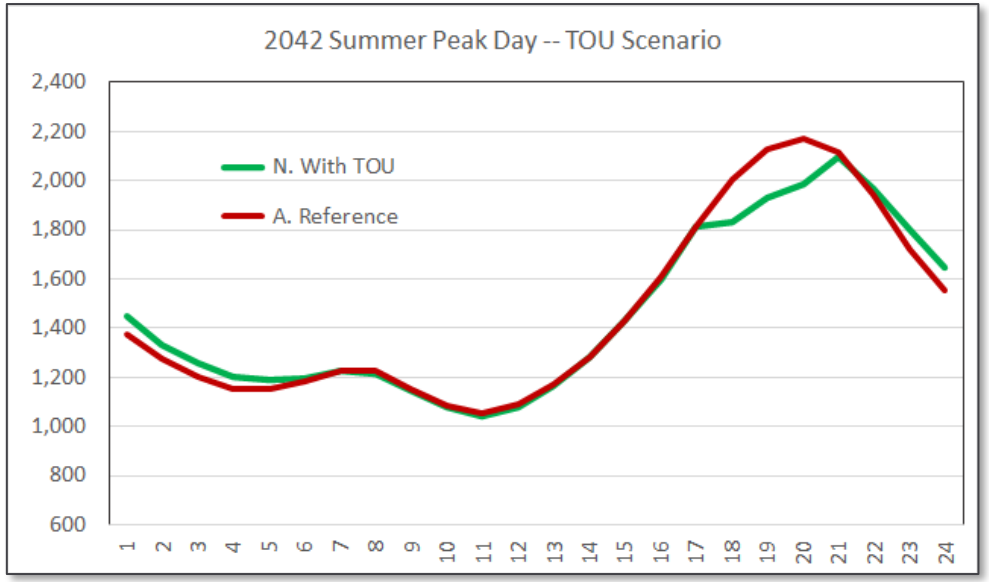


TOU Scenario

- The TOU scenario introduces residential TOU rate pilots in 2025, and full programs in 2030
  - Whole house EV Rate (10 pm to 5 am)
  - Opt-out TOU Rate (5-8 am, 5-8 pm)
- EV impacts based on EVPro profiles and PNM rate parameters.
- Non EV impacts based on TOU rate impact studies.

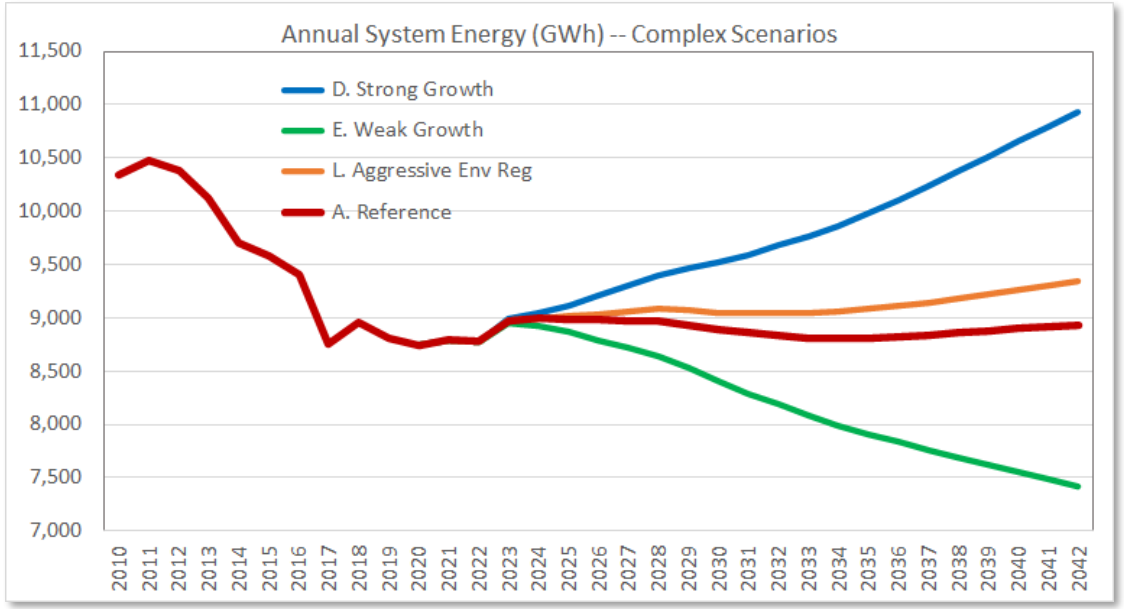
Year	Annual System Energy (GWh)		Annual Peak (MW)	
	Base	With TOU	Base	With TOU
2022	8,777	8,777	1,961	1,961
2027	8,978	8,977	1,898	1,890
2032	8,838	8,816	1,933	1,865
2037	8,839	8,814	2,033	1,968
2042	8,934	8,907	2,169	2,095



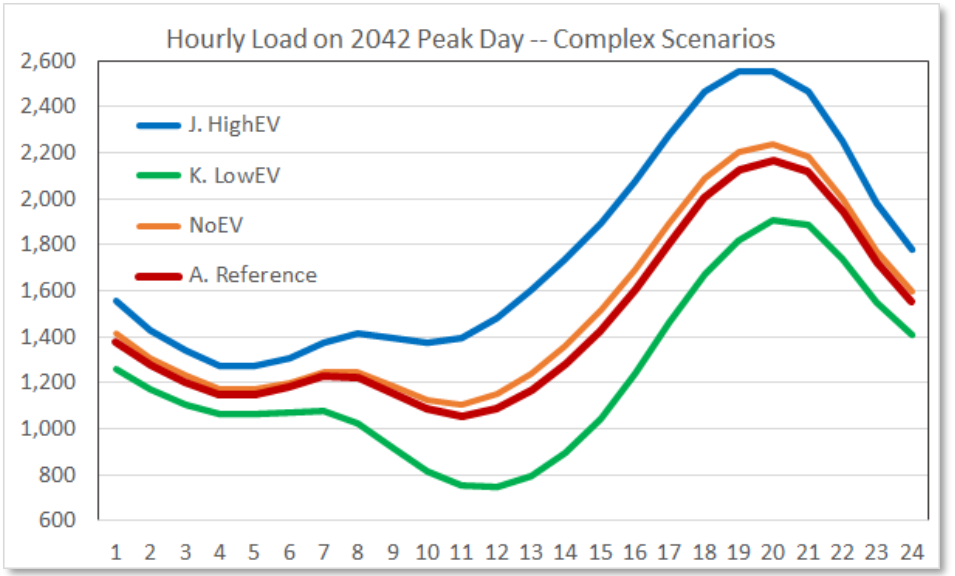


Complex Scenarios

- Strong Growth Scenario
  - High Econ Growth, Weak PV, Strong EV, Residential Electrification
- Weak Growth
  - Low Econ Growth, Strong PV, Weak EV
- Aggressive Environmental Regulation
  - Strong PV, Strong EV, Residential Electrification

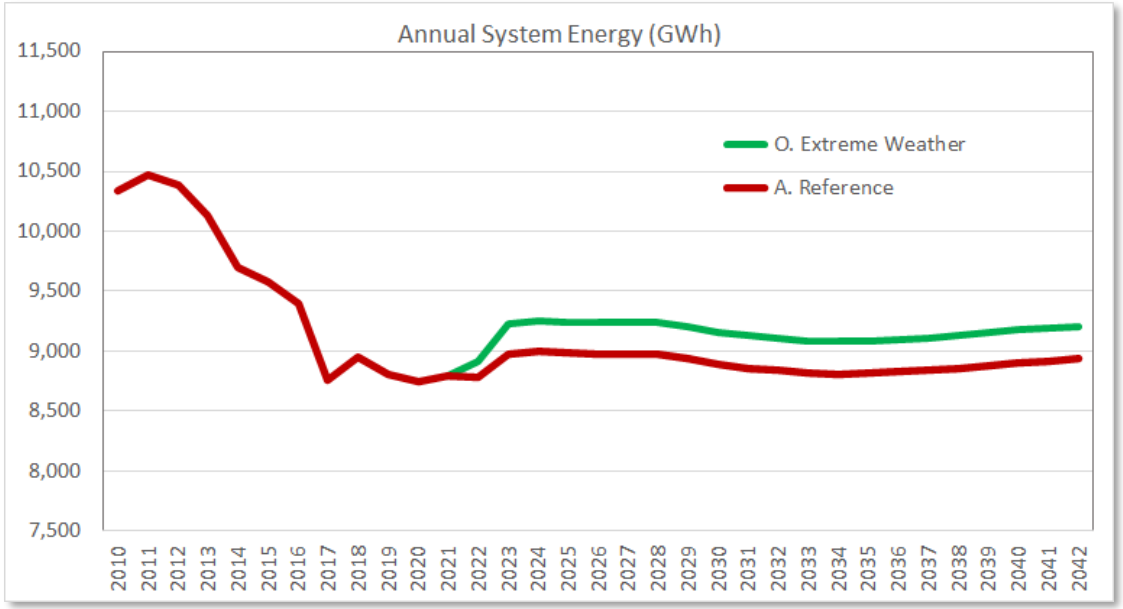


Year	Annual System Energy (GWh)				Annual Peak (MW)			
	Base	Strong Growth	Weak Growth	Aggressive Env Reg	Base	Strong Growth	Weak Growth	Aggressive Env Reg
2022	8,777	8,777	8,777	8,777	1,961	1,961	1,961	1,961
2027	8,978	9,307	8,723	9,060	1,898	1,970	1,843	1,914
2032	8,838	9,678	8,186	9,043	1,933	2,106	1,818	1,972
2037	8,839	10,236	7,759	9,147	2,033	2,313	1,852	2,087
2042	8,934	10,933	7,413	9,339	2,169	2,556	1,907	2,240

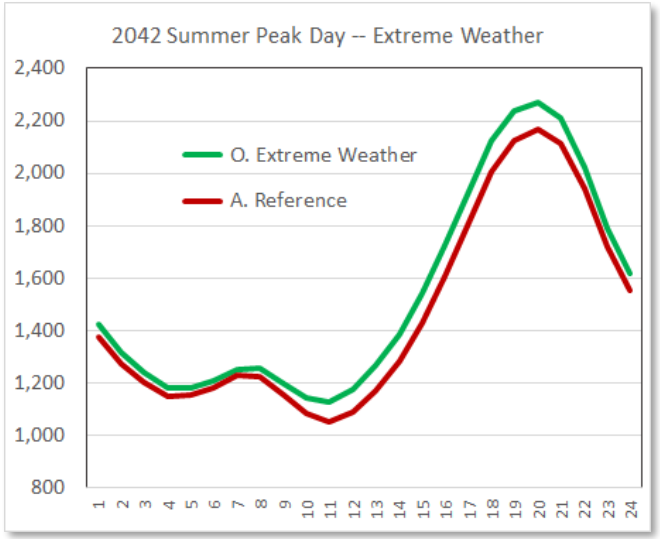


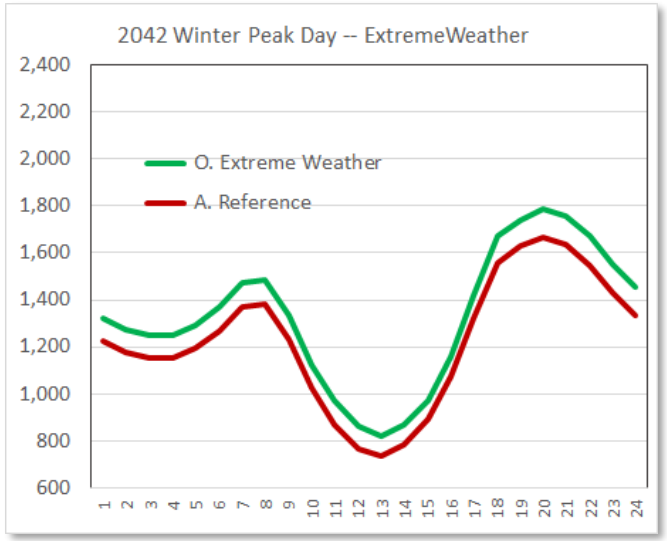
EXTREME WEATHER

- Reference uses rank and average
- Extreme uses rank and average of top 2
  - Summer peak day is 2.6 degrees warmer
  - Winter peak day is 12.2 degrees colder
  - Monthly HDD60 is 17% higher than normal
  - Monthly CDD65 is 17% higher than normal



Year	Annual System GWh		Summer Peak (MW)		Winter Peak (MW)	
	Base	Extreme Weather	Base	Extreme Weather	Base	Extreme Weather
2023	8,975	9,225	1,883	1,983	1,371	1,491
2027	8,978	9,242	1,898	2,003	1,435	1,559
2032	8,838	9,108	1,933	2,037	1,487	1,610
2037	8,839	9,111	2,033	2,130	1,583	1,705
2042	8,934	9,208	2,169	2,270	1,668	1,788





Putting EE on the Supply Side

- The forecast scenarios all include strong impacts from continued energy efficiency gains.

- To put EE on an equal footing with supply-side options, the scenario forecasts are adjusted upward to remove the impacts of incremental program activity, including:
  - The Program bundle for 2023 to 2027
  - Bundles A to E for 2028 and beyond

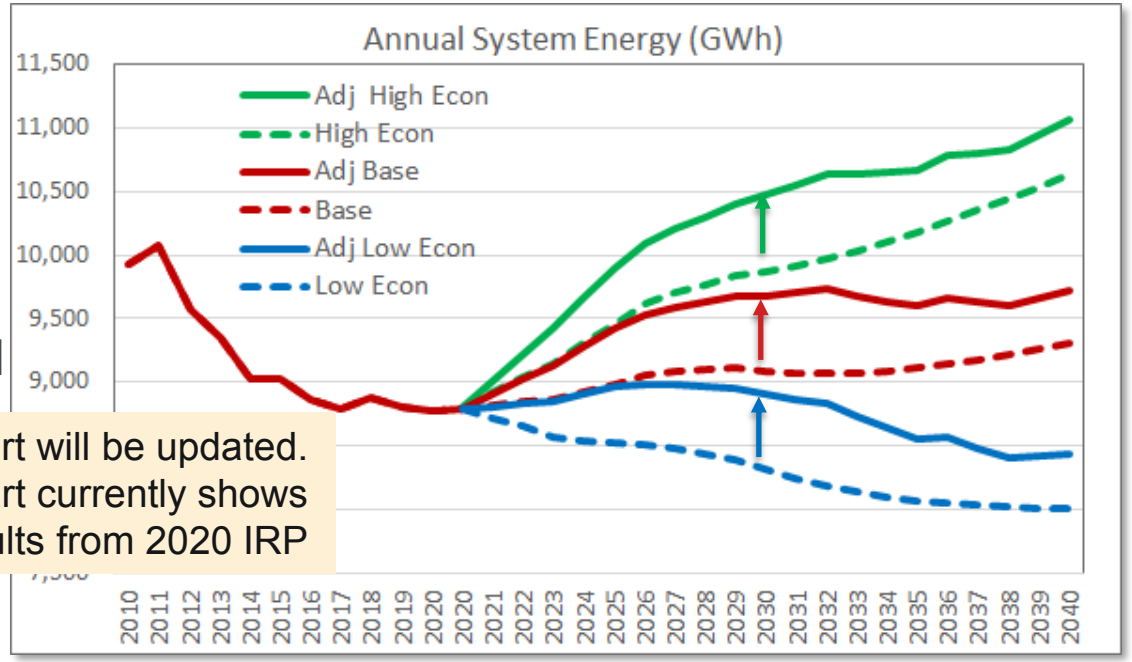


Chart will be updated. Chart currently shows results from 2020 IRP

- To compute the adjustments, load shape impacts by EE bundle are accumulated across years based on average measure life of each bundle. The cumulative impacts are then added to the hourly scenario forecast. The resulting adjusted hourly load shapes are the basis for the IRP process treating EE programs as a supply-side resource. The chart depicts the impact of this adjustment process for annual system energy in the three economic growth scenarios.

THANK YOU

stuart.mcmenamin@itron.com
david.simons@itron.com
forecasting@itron.com

Pricing and Rate Design Issues

Heidi Pitts – Lead Pricing Analyst

IRP STAKEHOLDERS

DECEMBER 15, 2022



DISCUSSION TOPICS

Time-of-Day pilot rate details

- How does the pricing incentive differ for residential customers?
- Proposed on-peak/off-peak hours
- Bill guarantee
- Rates and ratios

Pricing Advisory Committee (“PRAC”)

- What has been accomplished so far?
- What are future goals?
- Modern Rate Design and timeline
- Issues to consider

TIME-OF-DAY PILOT

Comparison of current TOU vs. proposed TOD

RATE CASE PROPOSALS: TIME-OF-USE AND TIME-OF-DAY

Current Time-of-Use (TOU) rates will continue

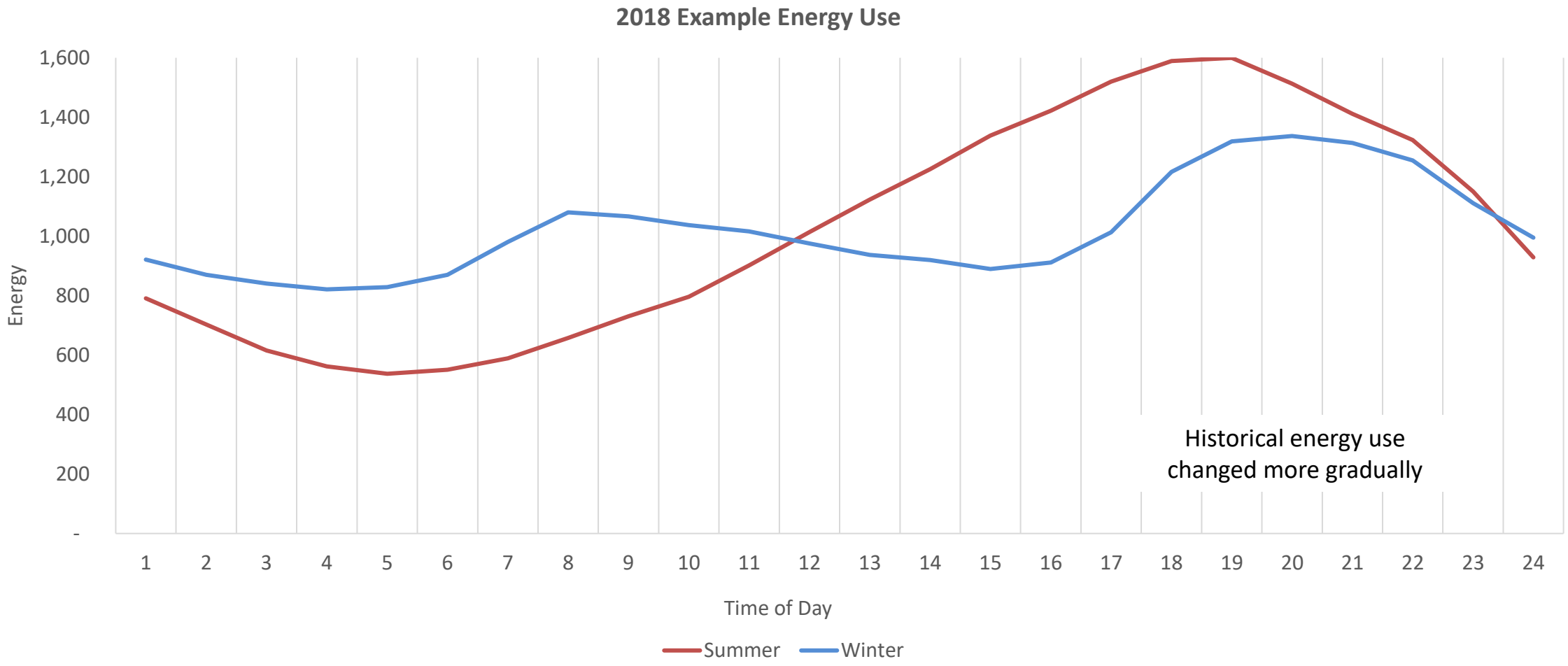
- However, Rates 1B Residential TOU and 2B Small Power TOU will be closed to new customers.
- Current TOU on-peak/off-peak hours will stay the same

Time-of-Day pilot proposed in rate case

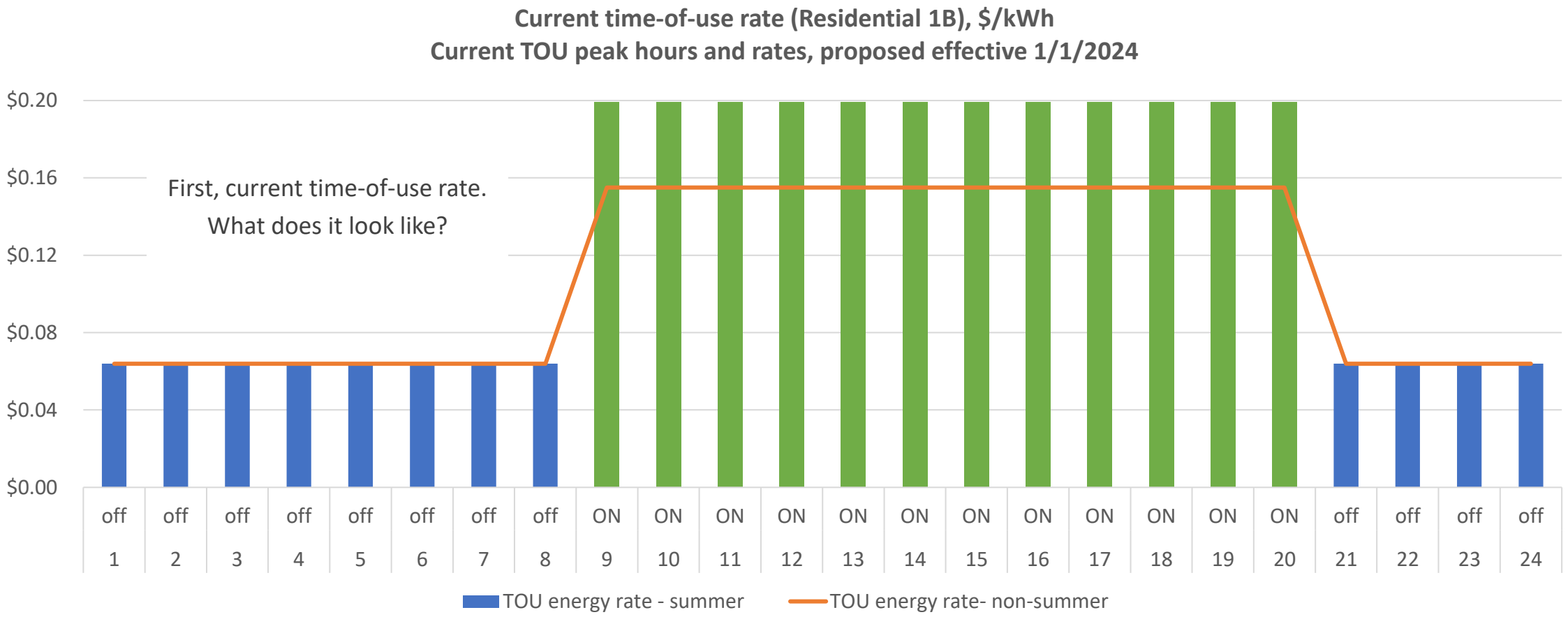
- Updated on-peak / off-peak hours and rates
- Bill guarantee for residential and small power
- Energy rates should reflect cost of energy

Starting with current TOU…..

CURRENT TIME-OF-USE REFLECTS HISTORICAL USAGE PATTERNS



CURRENT TIME-OF-USE RATES

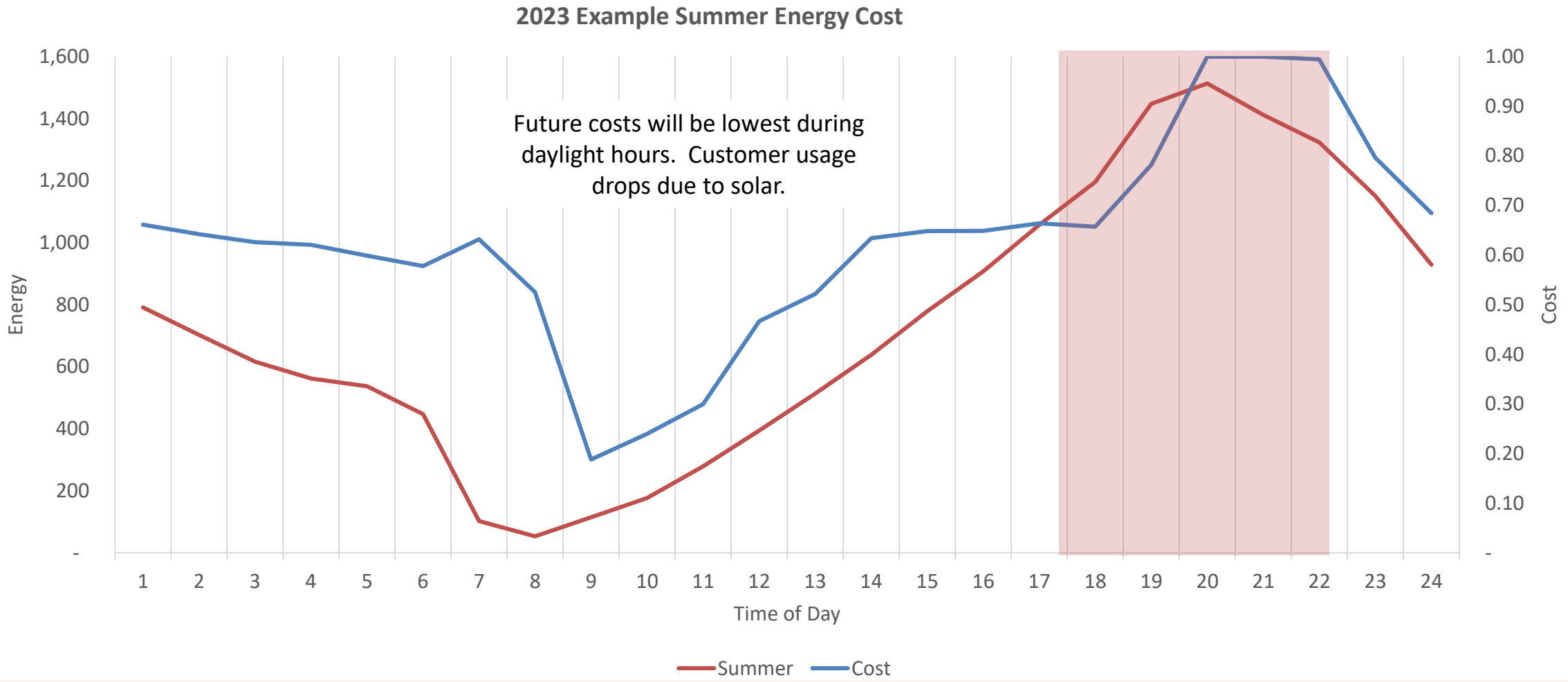


Talk to us.

TIME-OF-DAY OVERVIEW

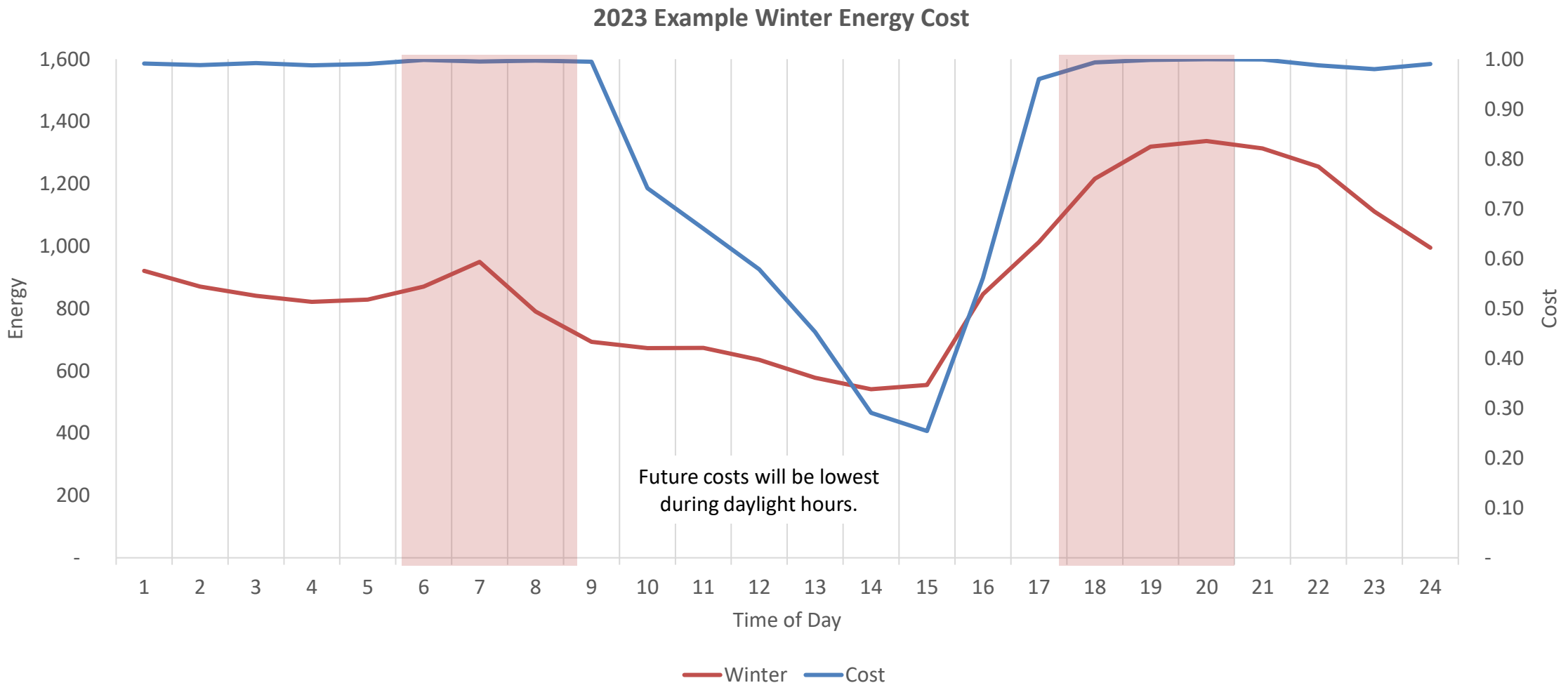
- Limited customer participation
  - 7,500 residential / 2,500 non-residential (all customer classes except 6, 20, 36B)
- Bill guarantee for residential and small power customers
- On peak M-F, June-Aug:
  - Residential: 5:00 to 8:00pm (15 hours/week)
  - Non-residential: 5:00 to 10:00pm (25 hours/week)
- On peak M-F, Sept to May:
  - Residential & non-residential: 5:00 to 8:00 am and pm (30 hrs/week)
- Super off-peak M-F, year-round:
  - Non-residential: 8:00am to 5:00pm (45 hours/week)
- Off-peak: all other hours
- Energy rates should reflect cost of energy – when customers use energy is the key to controlling their energy bills.

PILOT TIME-OF-DAY WILL REFLECT FUTURE DAYTIME ENERGY COST



PNM Talk to us. PNM.com

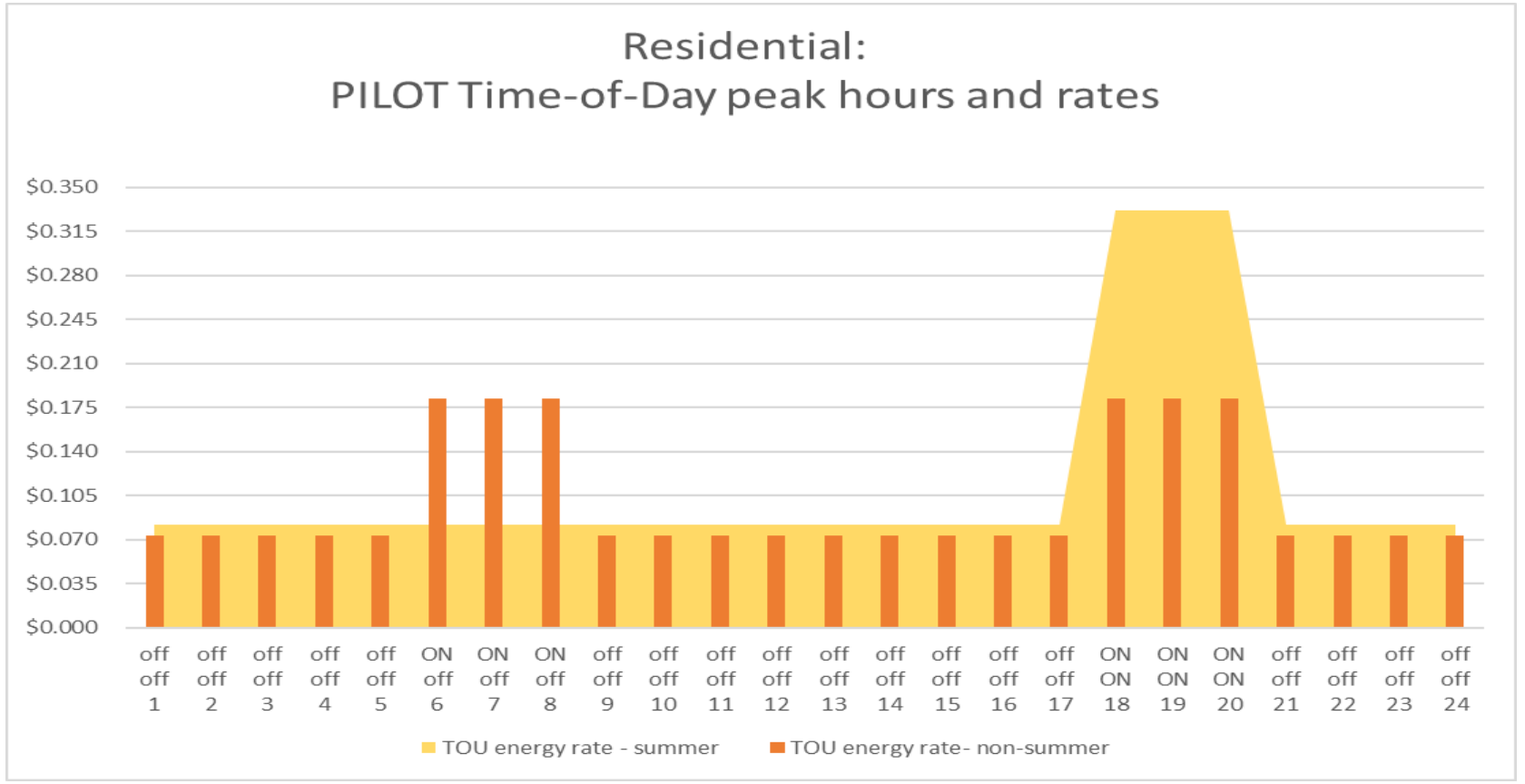
ENERGY COST DURING THE DAY – MOVING FORWARD



Talk to us.

RESULT IS A TIME-OF-DAY (TOD) RATE DESIGN

When customers use energy will inform the rate they pay, rather than how much they use.



Pricing Advisory Committee

Accomplishments and future goals

PRICING ADVISORY COMMITTEE (“PRAC”)

- Goal: a group to discuss Modern Rate Design issues

- Met in June, August, and September; plan to meet every 3-4 months going forward

- Topics of discussion to date:
    - Modern Rate Design
    - Low income customers, how to define and analyze
    - Inter-class subsidies
    - Cost allocation

PRAC – MODERN RATE DESIGN ISSUES TO CONSIDER

- Price signal should encourage consumption to help balance the grid (excess solar or at night)
- Net metering
- Customer choices
- Class subsidies
- Intermittent generation from renewable resources
- Energy Storage
- PPAs. Will more customers bring their own renewables?
- Electric vehicle adoption
- Cost allocation (fossil fuels historically → renewable energy future)
- Align cost allocation with cost causation

MODERN RATE DESIGN – RATE STRUCTURES

- Cellular interval meters
    - Pilot Whole House Electric Vehicle (WHEV) rate
    - Pilot Non-residential charging station
    - Pilot Time-of-Day rate (proposed in current rate case)
- AMI meters
    - TOD rates could be offered to all customers
    - Real time pricing
    - Critical peak pricing
- Modern billing system needed

Questions??????

NEAR-TERM SCHEDULE*

FUTURE MEETING TIME & LOCATION

When: January 17, 2023 (Tentative)

Topic: AEG EE bundles, PNM EE program & highlights, ELCC & PRM study results, Summer 2022 review

Start Time: 9:00 AM

Location: Virtual

**meeting dates and topics are subject to change based on presenter's availability*

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and address them in a future next meeting. Please have your submissions in by January 13, 2023.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: AEG EE Bundles, PNM EE Program & Highlights, Astrape ELCC Study Results, Review of Summer 2022 and Market Assistance included in Resource Adequacy Modeling

STEERING MEETING 10

JANUARY 17, 2023



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

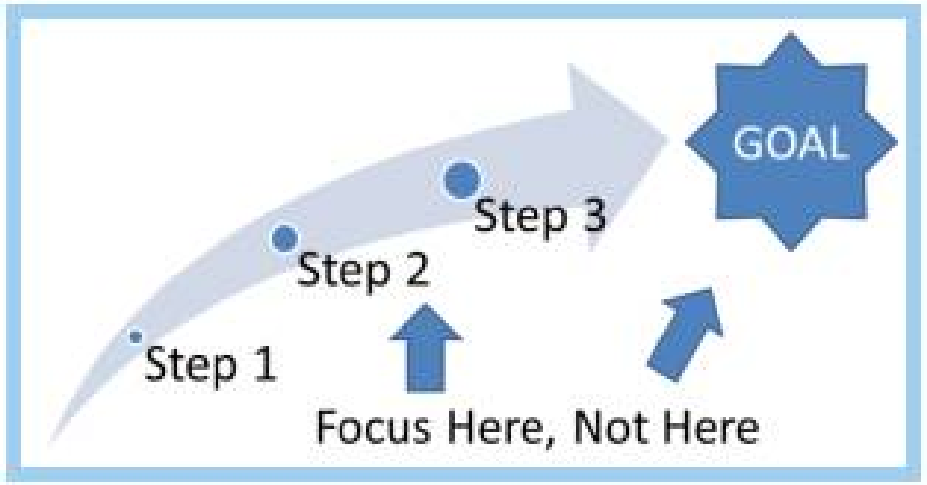
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

AEG
APPLIED ENERGY GROUP

EE Potential Study Stakeholder Meeting

January 17, 2023

Agenda

- Introductions
- Study Overview
- Energy Efficiency Potential
- IRP Inputs

Introductions



Kelly Marrin
Managing Director
Role: Project Director



Len Bergman
Manager
Role: Project Manager



Eli Morris
Managing Director
Role: IRP Input Lead



Rob Strange
Product Manager
Role: Modeling Lead



Fuong Nguyen
Lead Analyst
Role: Analysis Lead

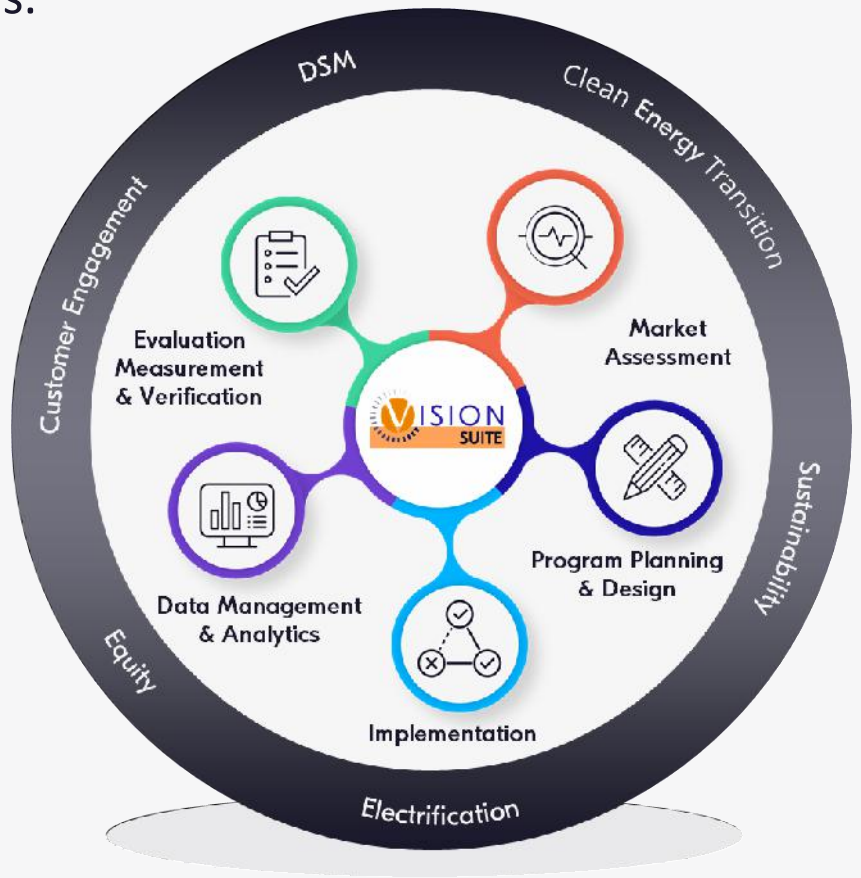
Presenter

About AEG

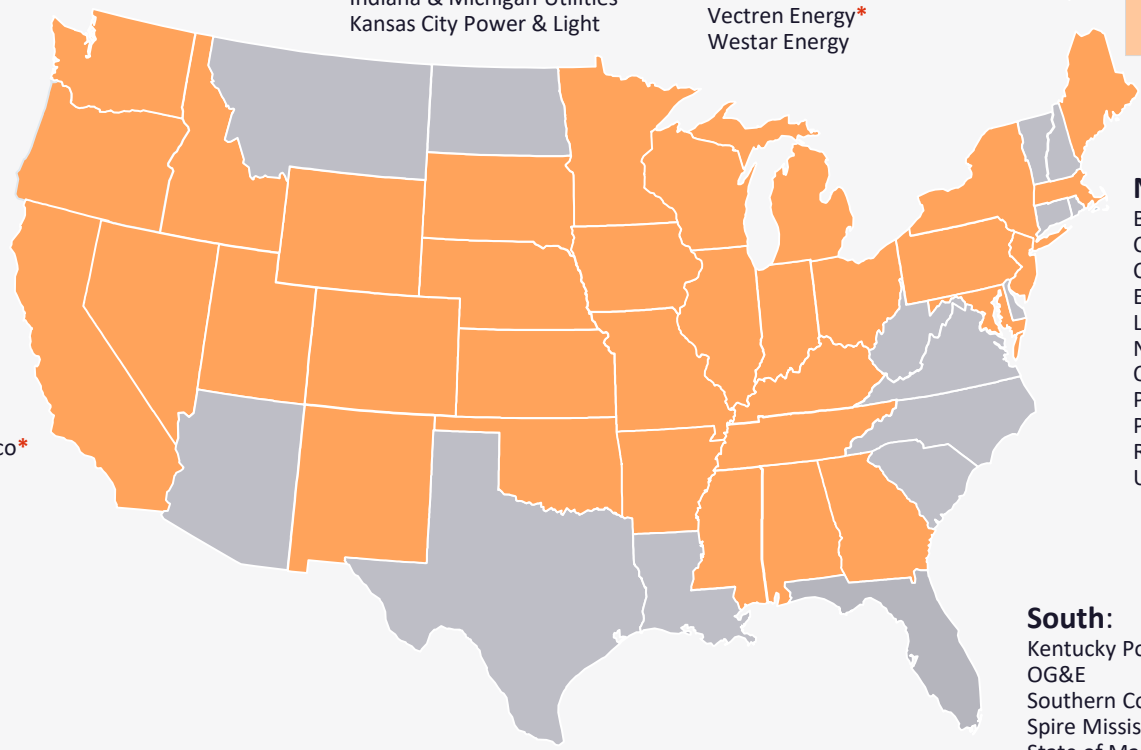
Founded in 1981 | Join Ameresco 2011

AEG provides expertise, products, and insights to utilities and other agencies to solve current and future business and sustainability needs.

115	Dedicated Professionals
49	States and provinces in which we've worked
200+	Utility and govt. clients served
1,000+	Projects completed



AEG's Market Potential Study Footprint



West:
Avista Energy*
BPA*
Cascade Natural Gas*
Chelan PUD
Cheyenne LFP *
Colorado Electric*
Cowlitz PUD*
HECO
Idaho Power*
Inland P&L*
LADWP
NV Energy
Oregon Trail EC
PacifiCorp*
PNGC
PG&E*
Portland General Electric
Public Service New Mexico*
Seattle City Light*
State of Hawaii*
State of New Mexico
Tacoma Power*
Xcel/SPS

Midwest:
Ameren Illinois*
Ameren Missouri*
Black Hills Power *
Citizens Energy
Empire District Electric *
Indianapolis P&L*
Indiana & Michigan Utilities
Kansas City Power & Light
MERC
NIPSCO*
Omaha Public Power District*
Peoples' Gas/ North Shore Gas *
Spire Missouri
State of Michigan
Sunflower Electric
Vectren Energy*
Westar Energy

Regional & National:
Midcontinent ISO*
EEI/IEE*
EPRI
FERC

Northeast:
Berkshire Gas
Central Hudson G&E *
Con Edison of NY *
Efficiency Maine *
Liberty Utilities *
New Jersey BPU
Orange & Rockland *
PECO Energy
PSEG Long Island
Rockland Electric
Unitil

South:
Kentucky Power
OG&E
Southern Company / Georgia Power
Spire Mississippi
State of Maryland – EmPOWER *
TVA

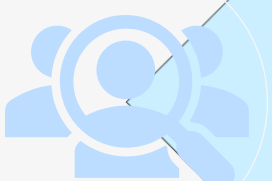
* **Two or more studies**

As of November 2022

- 60 potential studies in last 5 years
- Currently performing potential studies in New Mexico, Washington, Oregon, Idaho, Utah, Wyoming, California,, Michigan, Missouri, Maryland, and Washington DC

Study Objectives

There are 3 overarching objectives for the study



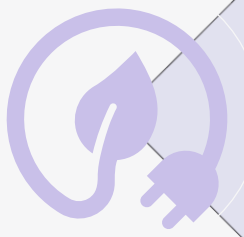
Incorporate Key Updates from the 2019 Study

- Incorporate results from the 2020 RASS that AEG completed with Itron
- Perform limited updates to the measure list



Develop New Projection of EE Potential

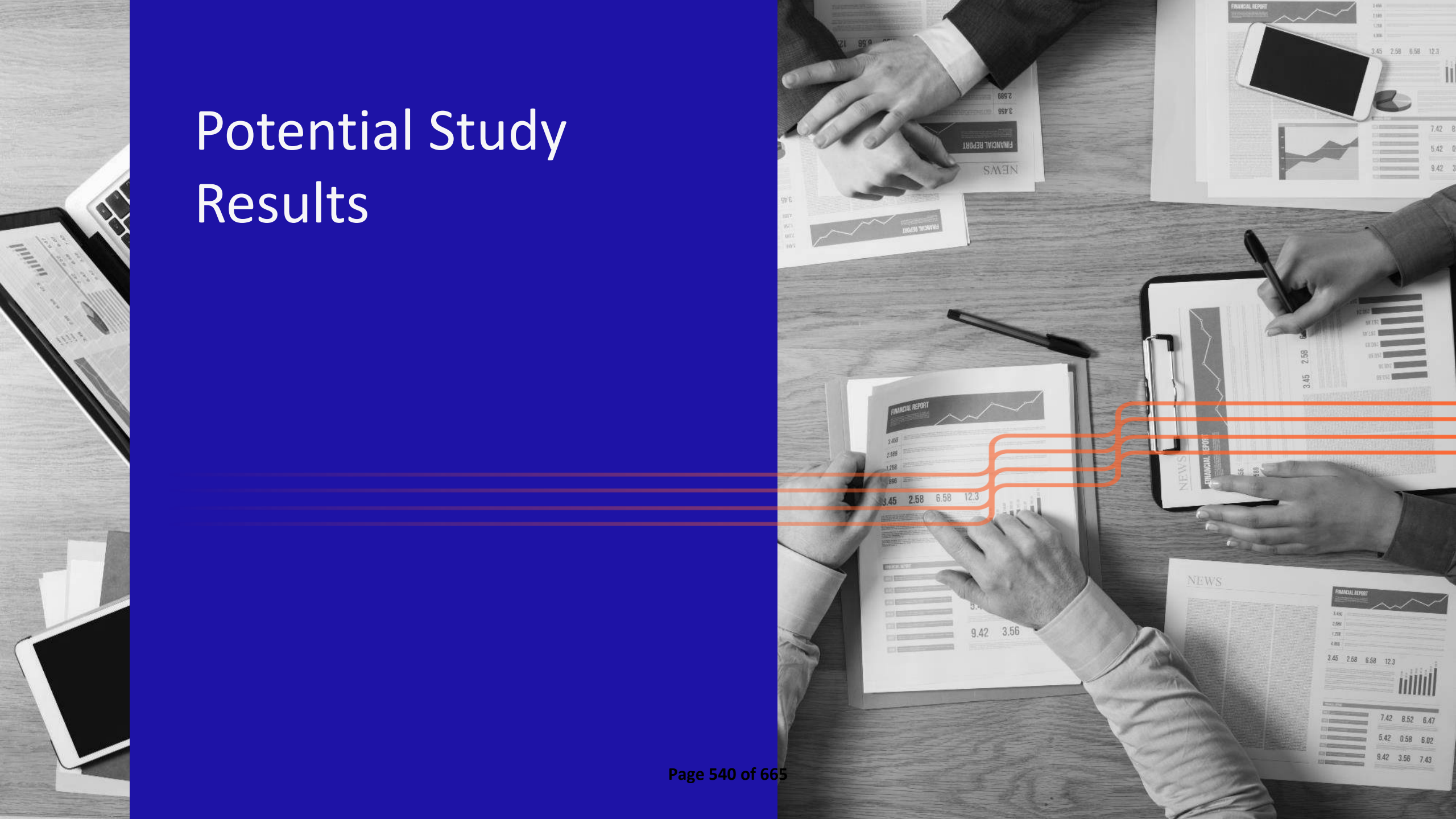
- Align with Itron's EE forecast and program scenarios
- Review long-term achievability assumptions
- Project technical, economic, and achievable EE potential through 2044



IRP Bundle Development

- Determine the "right" number of EE bundles based on the previous study
- Develop bundle cutoffs
- Supply finalized bundles in IRP format

Potential Study Results



Energy Efficiency Potential Approach

Market Characterization

- Customer segmentation
- Utility data
- Residential Surveys
- Secondary data

Identify and Characterize Measures

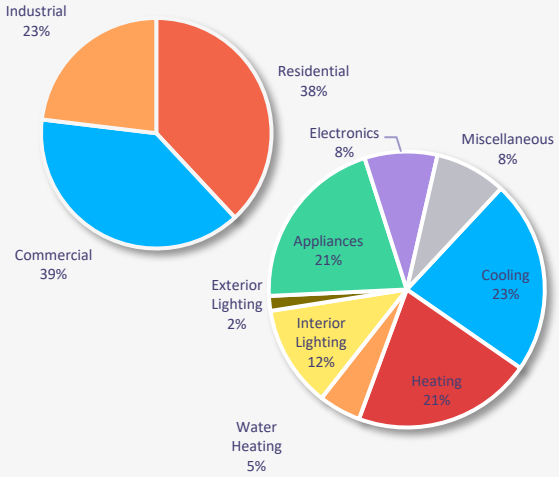
- Efficiency equipment
- Retrofit opportunities
- Emerging technologies

Baseline Projection

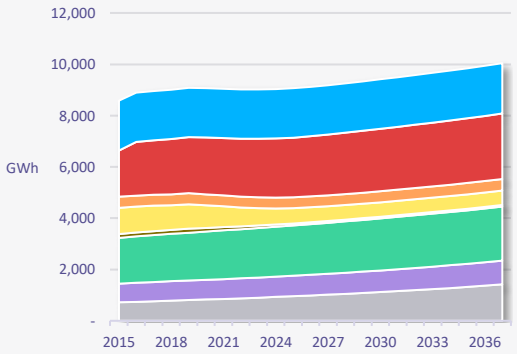
- Utility forecasts
- Stock turnover
- Codes and standards

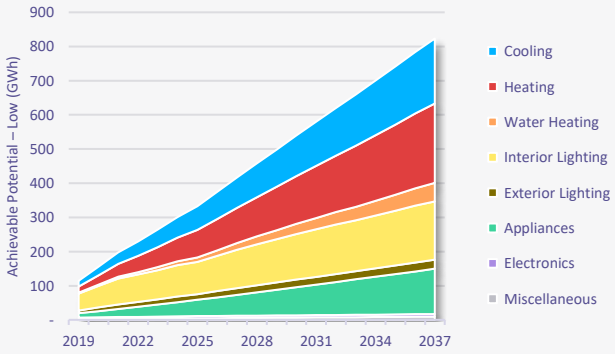
Potential Estimation

- Technical , Economic, and Achievable
- Scenario representing current statutory goals







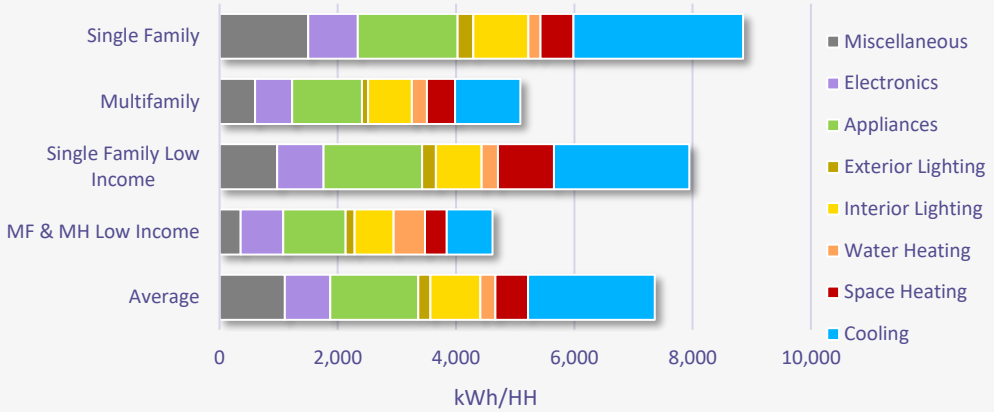


Market Characterization

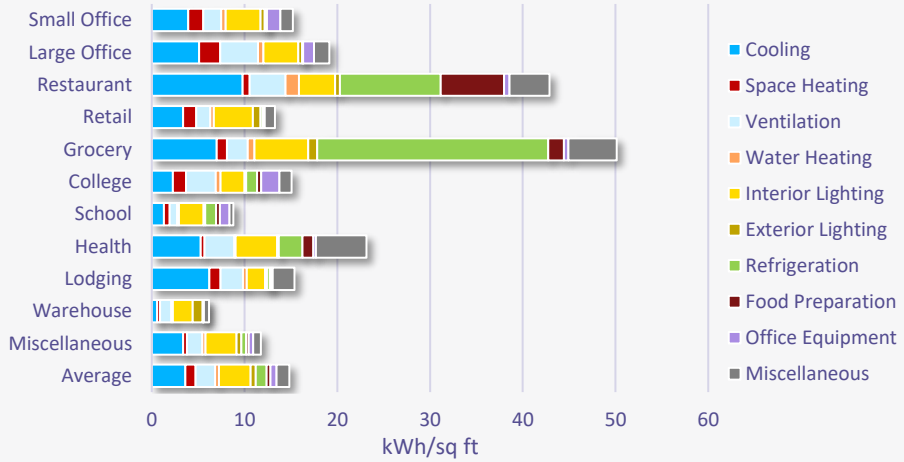
Key Elements and Drivers

- Market characterization is anchored to actual sales and customers in study base year (2021)
- Segment residential sector based on dwelling type and income
- Segment C&I sector by building type using SIC codes
- Fully characterize energy consumption by sector, segment, end-use, and technology
  - We call these “market profiles”
- **Market Profiles provide insight into baseline equipment and usage, bound technical potential, and establish eligibility to adopt EE measures**

Residential Market Characterization for 2021

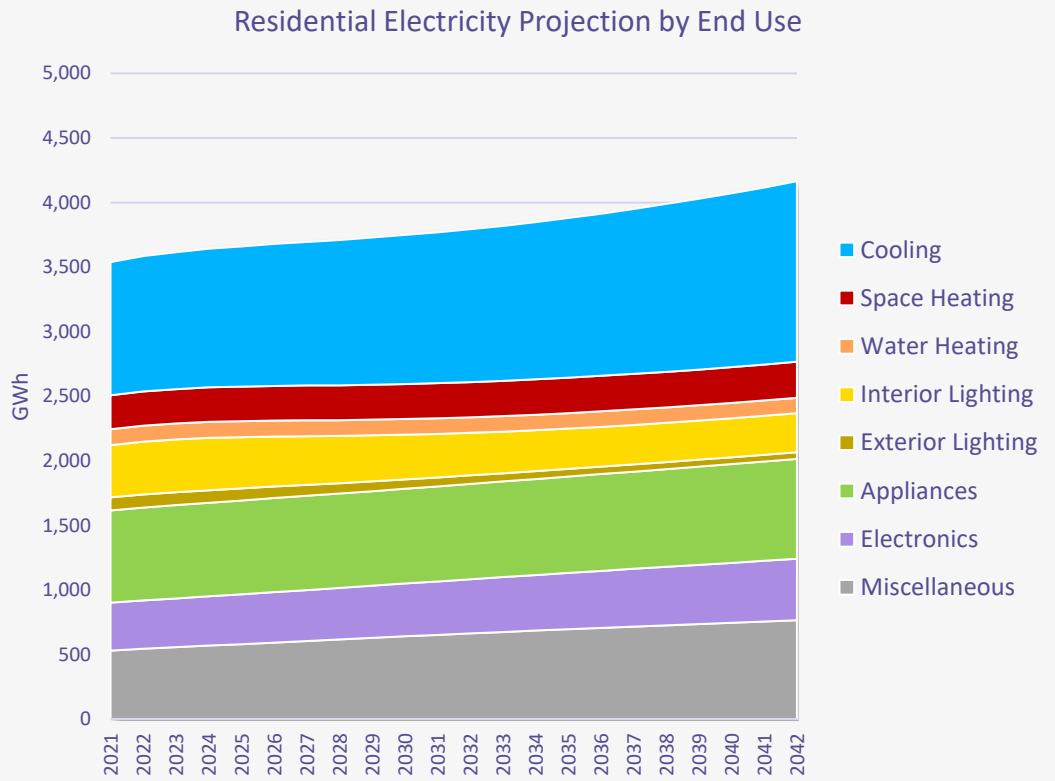


Commercial Market Characterization for 2021

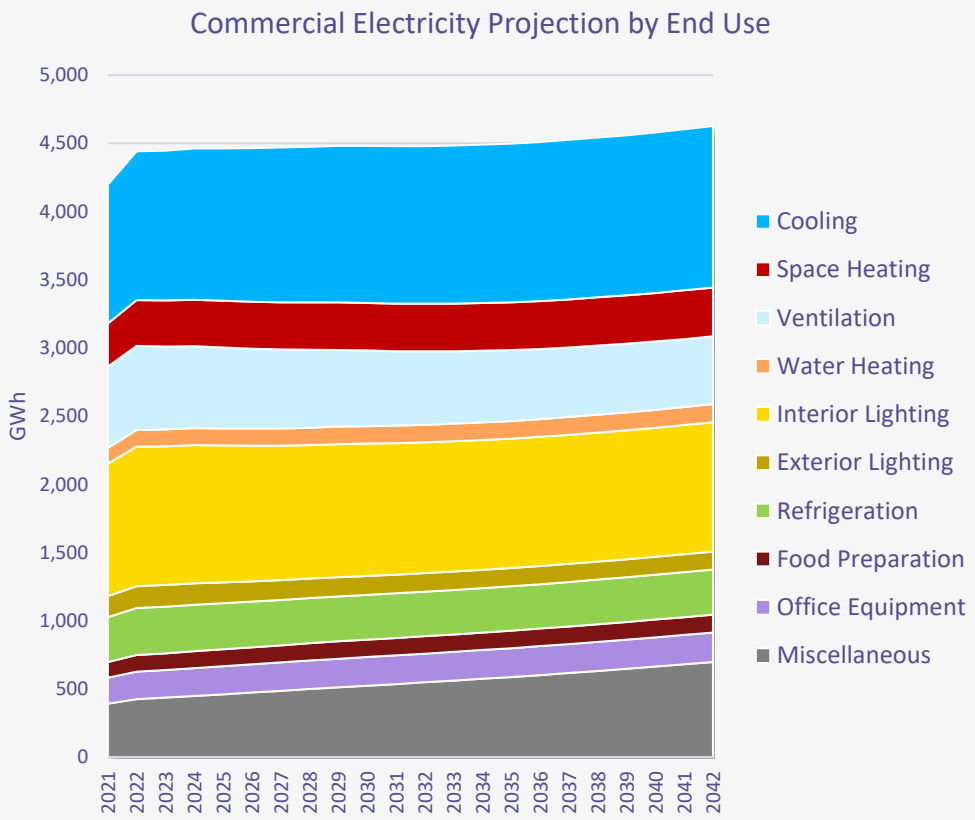


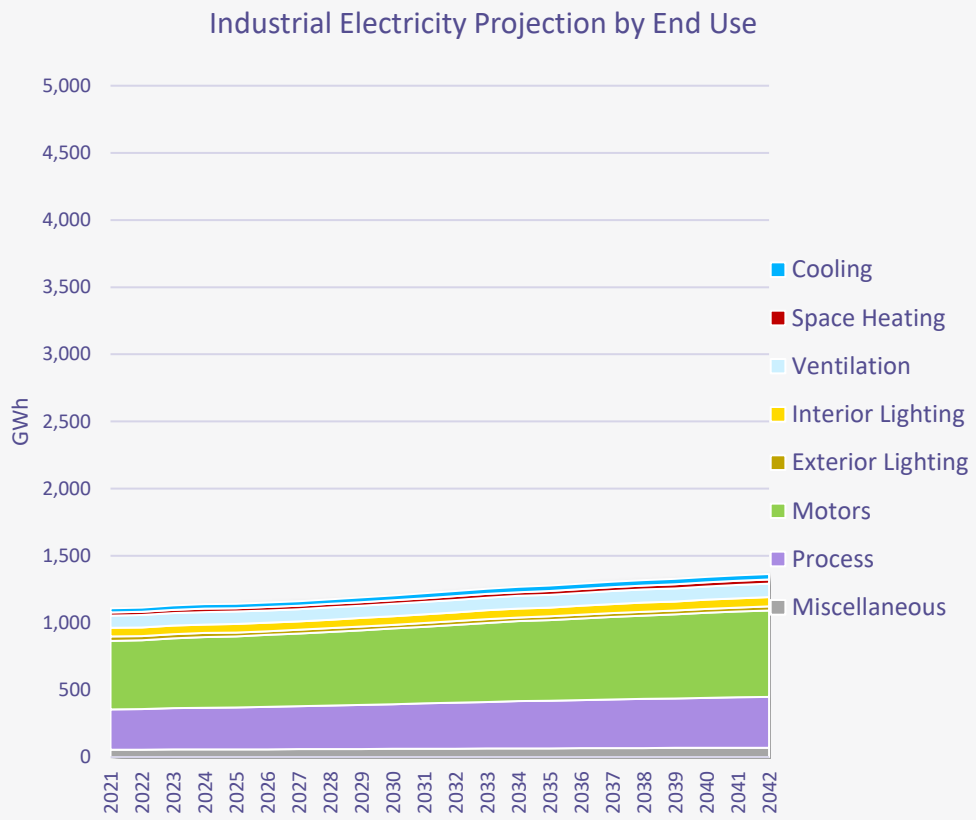
Residential Baseline Projection

- Projects end-use consumption in the absence of future program interventions
  - This is the basis from which potential is estimated
- Accounts for:
  - Differences by sector, and segment
  - Customer growth
  - Codes and standards **(including EISA lighting)**
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations

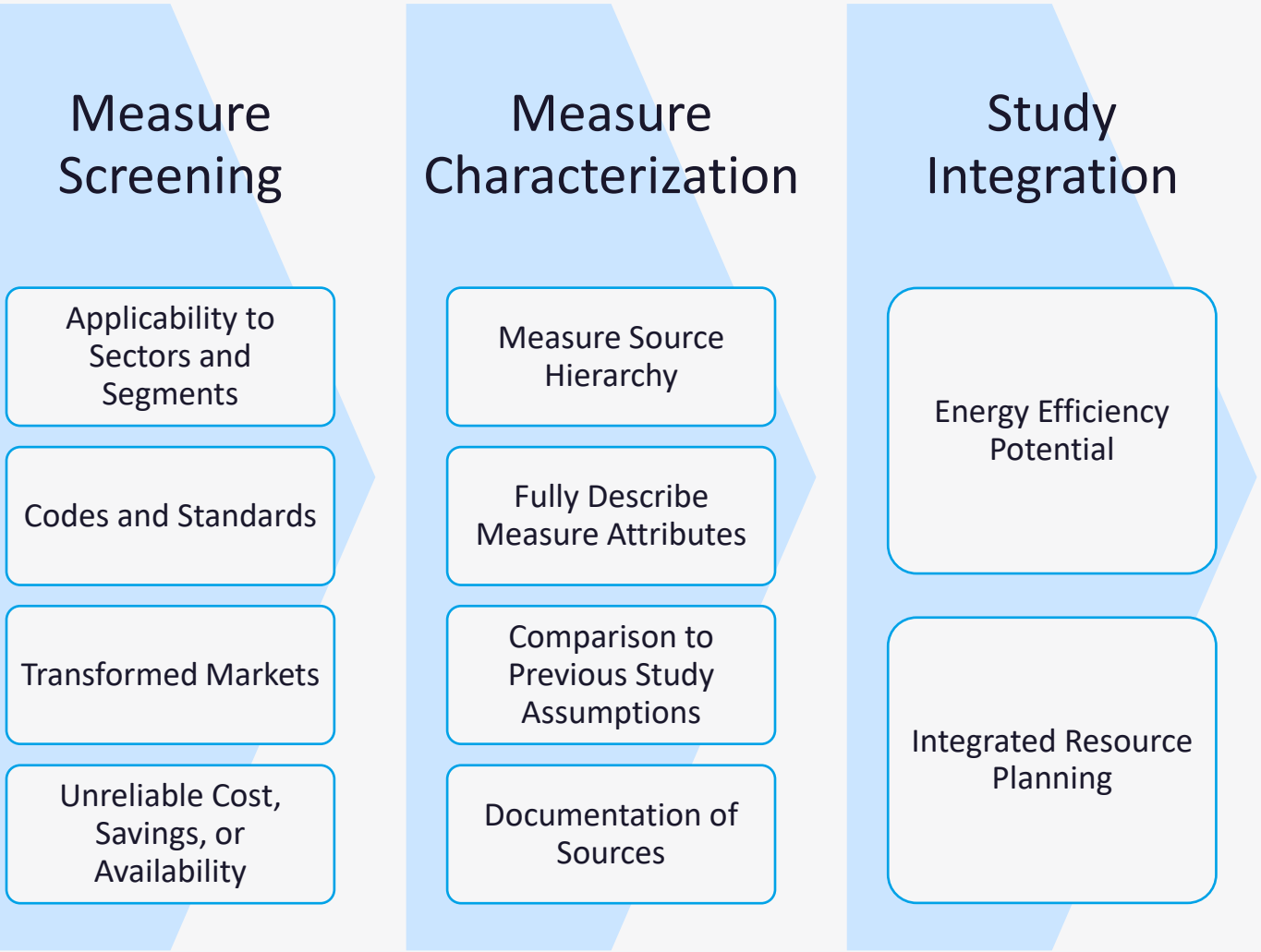


C&I Baseline Projection



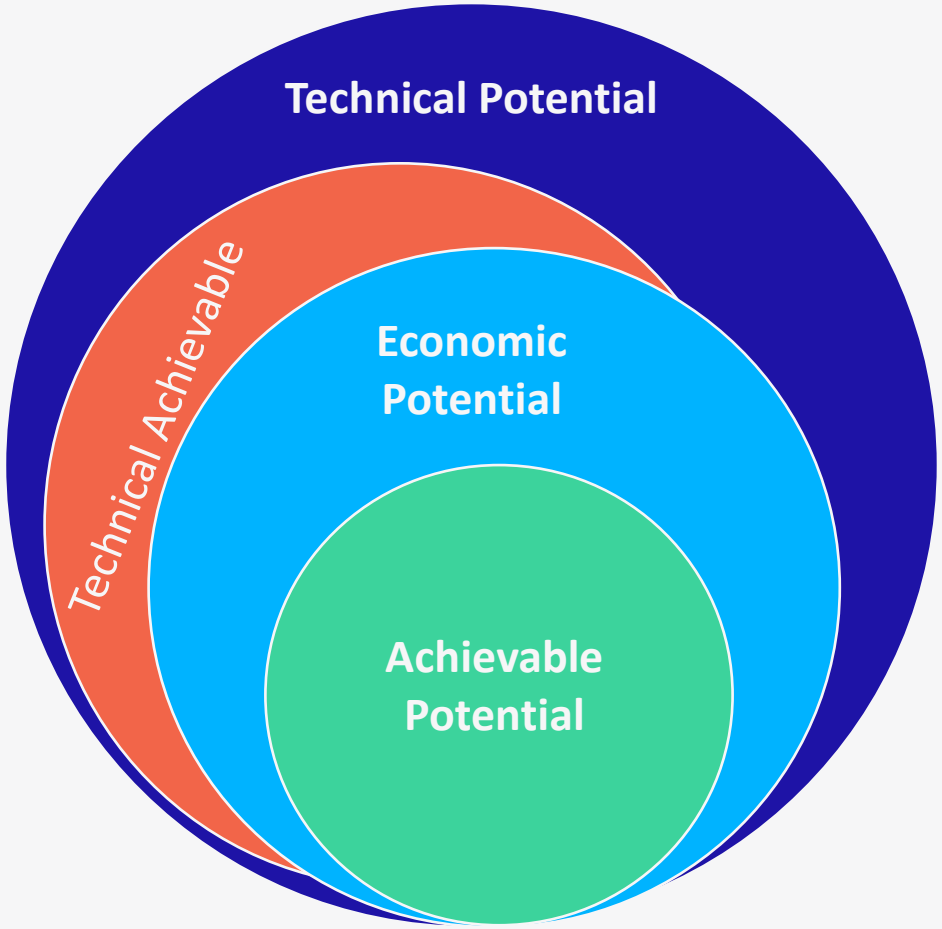


Measure Identification and Characterization



Estimating Energy Efficiency Potential

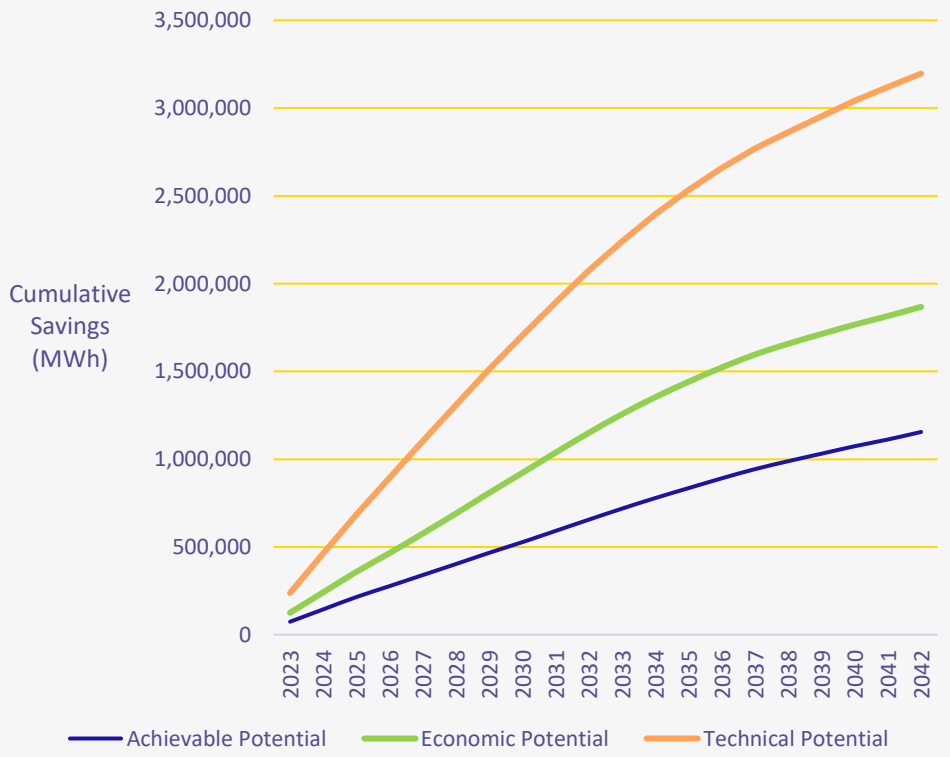
- Potential is estimated by creating an alternate sales forecast incorporating efficient measure adoption and calculating the change from the baseline
- AEG will calculate five distinct levels of potential:
  - Technical
  - Technical Achievable
  - Economic
  - Achievable
- AEG will also incorporate various scenarios that represent achievement of Statutory spending goals



Potential Summary for All Sectors

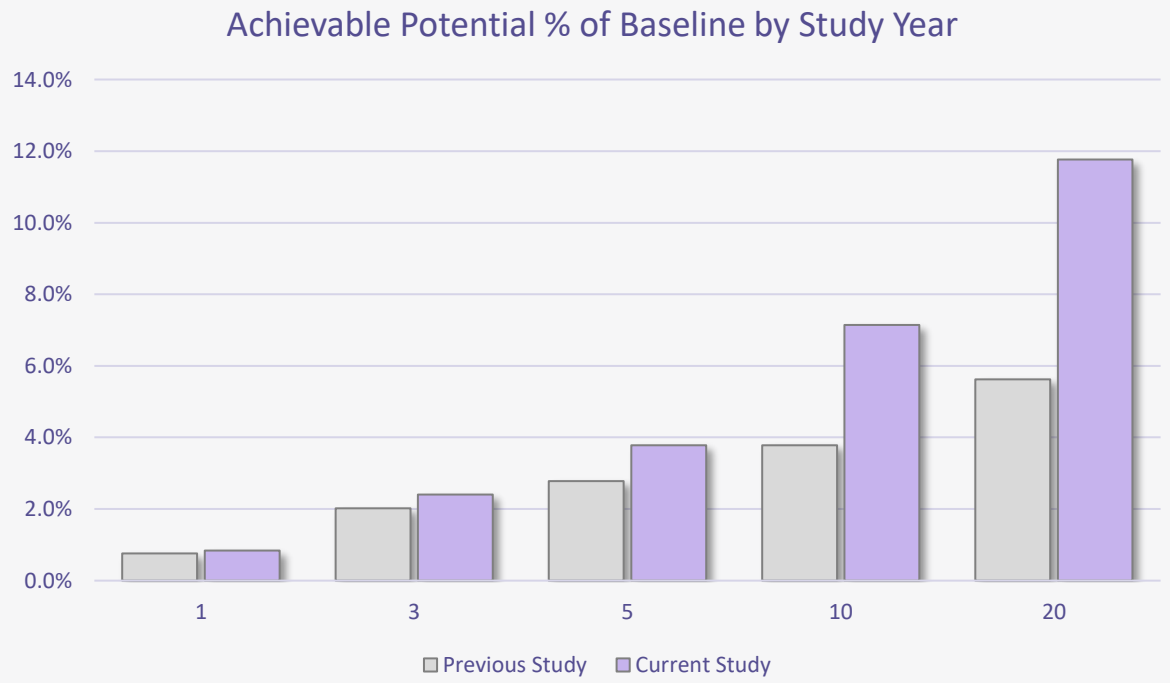
- Achievable Potential savings in the first year of 75 GWh, 0.8% of baseline usage.
- Achievable Potential savings reach 11.8% of baseline usage by 2042, an average of 0.6% annually
- 20-year Achievable Potential is 62% of Economic Potential

Summary of Energy Savings	2023	2025	2027	2032	2042
Baseline Projection (MWh)	8,917,779	8,981,490	9,026,886	9,192,373	9,819,602
Cumulative Savings (MWh)					
Achievable Potential	75,064	215,808	341,018	656,349	1,155,181
Economic Potential	126,169	359,266	577,575	1,150,697	1,867,135
Technical Potential	238,016	687,057	1,104,022	2,075,023	3,197,540
Energy Savings (% of Baseline)					
Achievable Potential	0.8%	2.4%	3.8%	7.1%	11.8%
Economic Potential	1.4%	4.0%	6.4%	12.5%	19.0%
Technical Potential	2.7%	7.6%	12.2%	22.6%	32.6%



Comparison to Previous Study

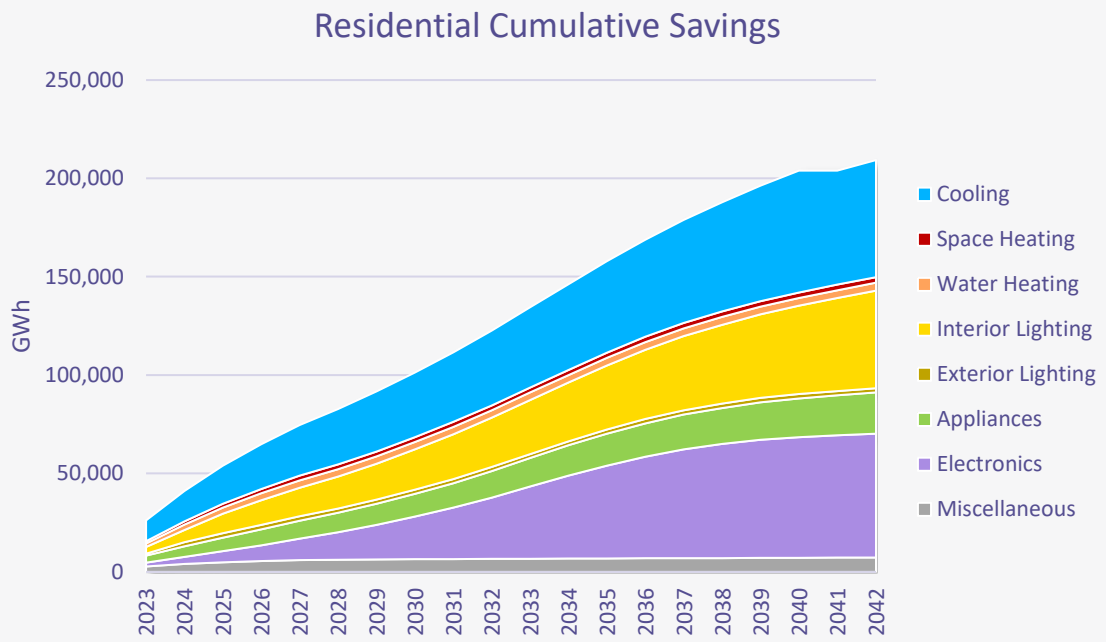
- In the short term, Achievable Potential savings are similar to the previous study
  - The previous study used a conservative growth rate for energy efficiency adoption, which was an average of 0.5% linear growth
- The current study incorporates adoption rates to diffuse savings based on an S-shaped curve
  - This reflects a measure's slow growth from early adopters, to an accelerated adoption rate once the measure reaches its technical maturity

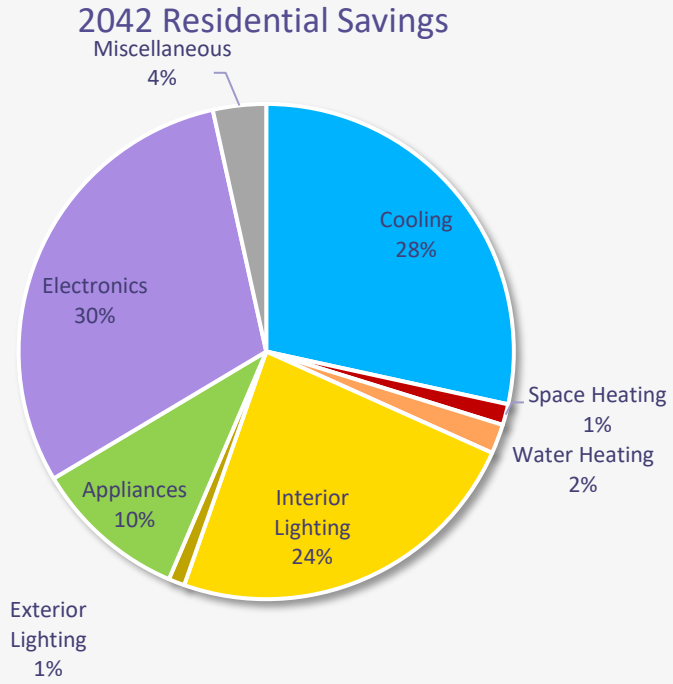


Residential Potential by End Use and Segment

Cumulative Achievable Potential in 2042

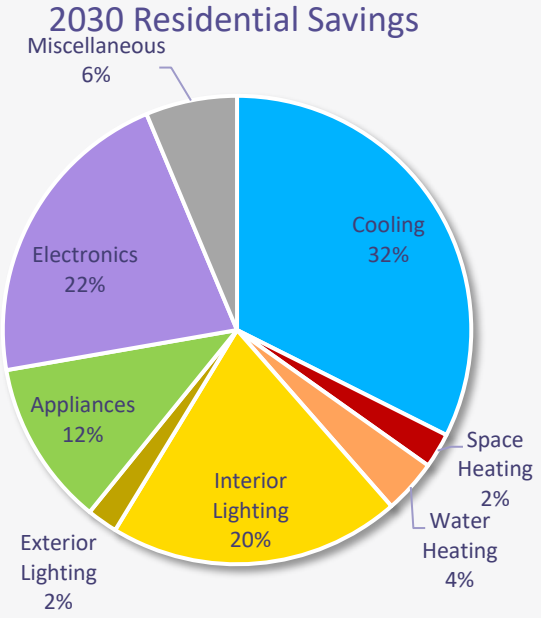
- By 2042, Electronics contribute that largest portion of savings, followed closely by Cooling and Lighting end use





Residential Top Measures – Achievable Potential

- Behavioral Programs provide the highest savings in 2030, followed by Central AC equipment replacements
- General Service Lighting potential is significantly lower than prior studies due to the implementation of the EISA backstop provision

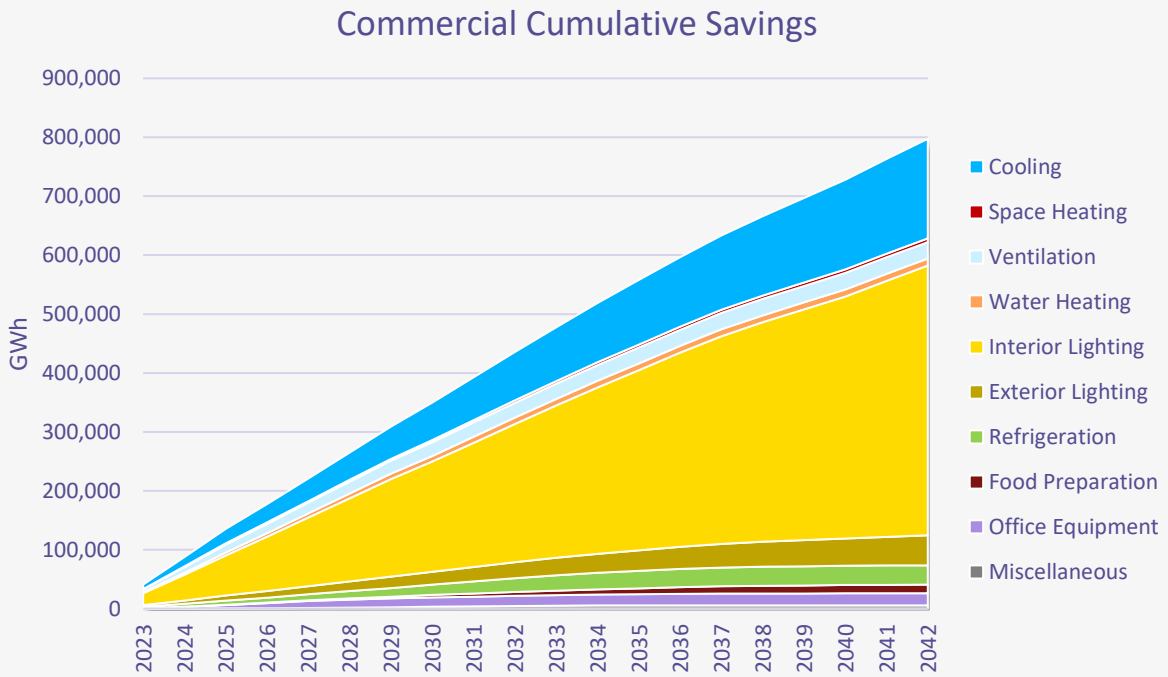


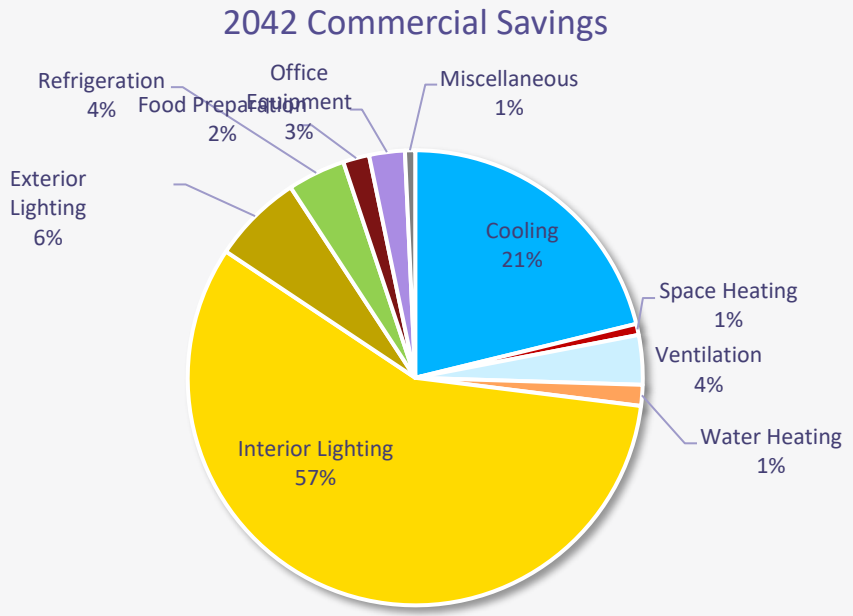
Rank	Measure	Achievable Potential in 2025	Achievable Potential in 2030	% of Total
1	Behavioral Programs	28,109	31,960	31.6%
2	Central AC	9,170	20,077	19.8%
3	Linear Lighting	2,758	12,681	12.5%
4	Set-top Boxes/DVR	836	7,571	7.5%
5	TVs	877	7,420	7.3%
6	General Service Lighting	5,547	6,367	6.3%
7	Clothes Dryer	1,170	4,520	4.5%
8	Personal Computers	718	2,625	2.6%
9	Air-Source Heat Pump	374	1,649	1.6%
10	Room AC - Recycling	1,303	1,356	1.3%
11	Water Heater - Pipe Insulation	1,069	1,276	1.3%
12	Water Heater - Tank Blanket/Insulation	1,025	1,161	1.1%
13	Laptops	183	401	0.4%
14	Pool Pump - Timer	120	384	0.4%
15	Second Refrigerator	52	331	0.3%
16	Exempted Lighting	266	309	0.3%
17	Printer/Fax/Copier	96	307	0.3%
18	Water Heater - Faucet Aerators	245	293	0.3%
19	Freezer	48	176	0.2%
20	Water Heater (> 55 Gal)	25	161	0.2%
	Total Top 20 Measures	**53,988**	**101,027**	**99.8%**
	Total Measures	**53,998**	**101,214**	**100.0%**

Commercial Potential by End Use and Segment

Cumulative Achievable Potential in 2042

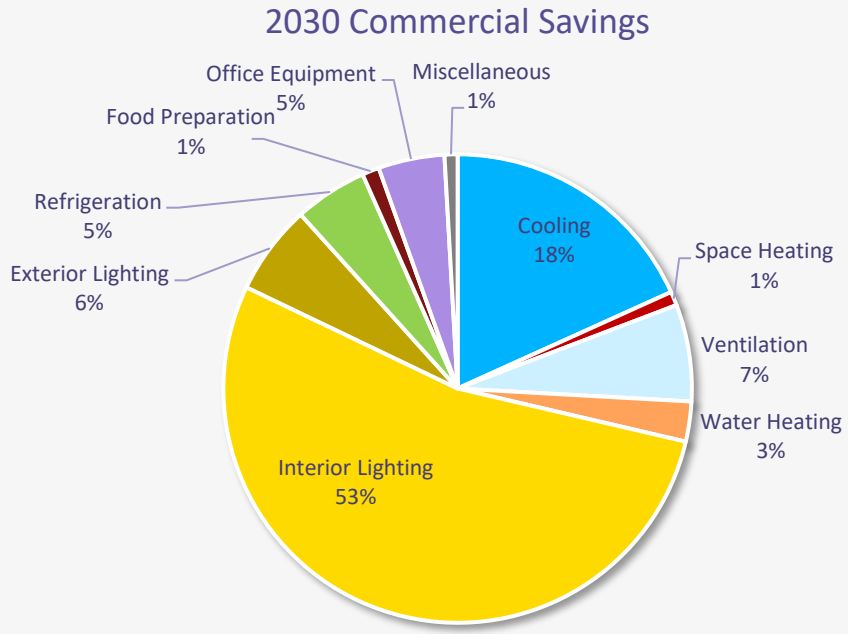
- Lighting represents the majority of savings in the Commercial sector, followed by the Cooling end use





Commercial Top Measures – Achievable Potential

- Linear and High-Bay Lighting continue to provide the most savings, including both lamps/fixtures and control technologies
- Significant additional cost-effective opportunities exist for retrocommissioning, ventilation, and efficient office equipment.

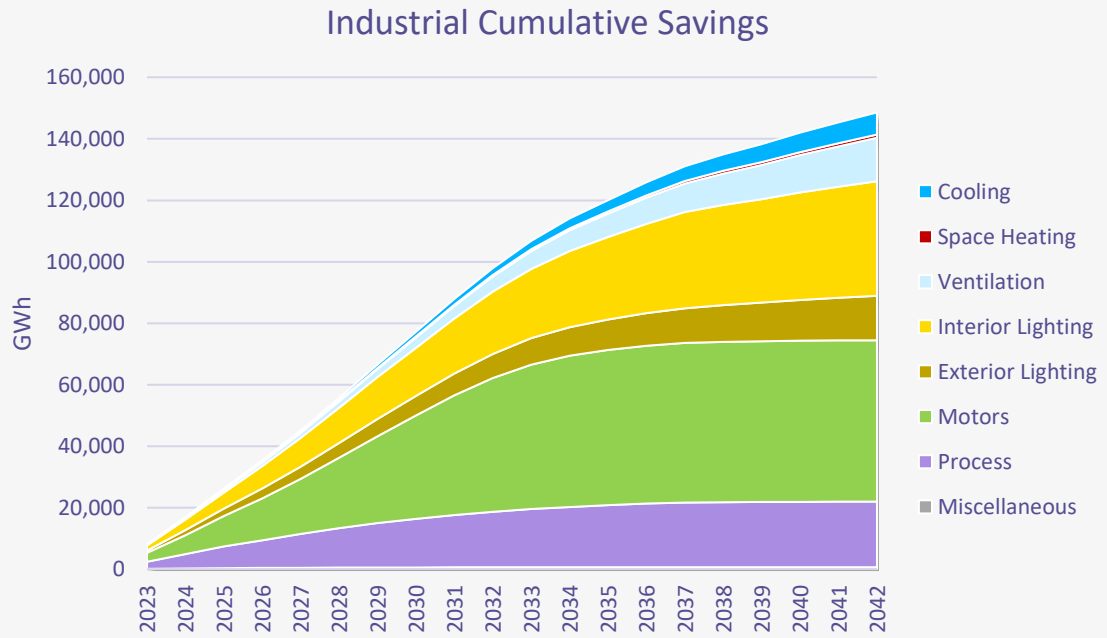


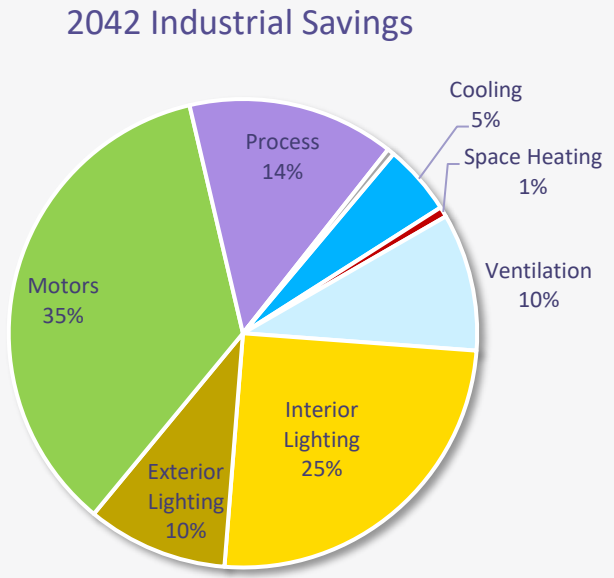
Rank	Measure	Achievable Potential in 2025	Achievable Potential in 2030	% of Total
1	Linear Lighting	53,296	159,134	45.5%
2	High-Bay Lighting	10,436	30,509	8.7%
3	Retrocommissioning	31,491	28,841	8.2%
4	Ventilation - Variable Speed Control	7,052	15,632	4.5%
5	Desktop Computer	4,621	12,785	3.7%
6	Water-Cooled Chiller - Condenser Temp Reset	3,633	9,395	2.7%
7	Water-Cooled Chiller	1,285	7,988	2.3%
8	RTU	876	7,269	2.1%
9	Ventilation - Nighttime Air Purge	1,591	6,304	1.8%
10	Water Heater - Pipe Insulation	2,059	4,977	1.4%
11	Water-Cooled Chiller - Var Flow Condenser Pump	1,823	4,643	1.3%
12	Area Lighting	1,405	4,089	1.2%
13	Refrigeration - Variable Speed Compressor	355	3,902	1.1%
14	Chiller - Variable Speed Fans	1,394	3,219	0.9%
15	Chiller - Variable Flow Chilled Water Pump	1,357	3,122	0.9%
16	Interior Lighting - Retrofit - Networked Lighting Controls	534	2,750	0.8%
17	Engine Block Heater Controls	428	2,672	0.8%
18	General Service Lighting	1,305	2,601	0.7%
19	Air-Source Heat Pump	316	2,575	0.7%
20	Ducting - Repair and Sealing	243	2,547	0.7%
	Total Top 20 Measures	**125,500**	**314,953**	**90.0%**
	Total Measures	**135,503**	**349,987**	**100.0%**

Industrial Potential by End Use and Segment

Cumulative Achievable Potential in 2042

- Savings in the motors end use are made up of pump and fan controls, as well as Compressed Air measures
- Process end use savings come from Refrigeration optimization measures such as High Efficiency Compressors and Floating Head Pressure
- Lighting savings in this sector come from conversion of High-Bay Lighting to LEDs

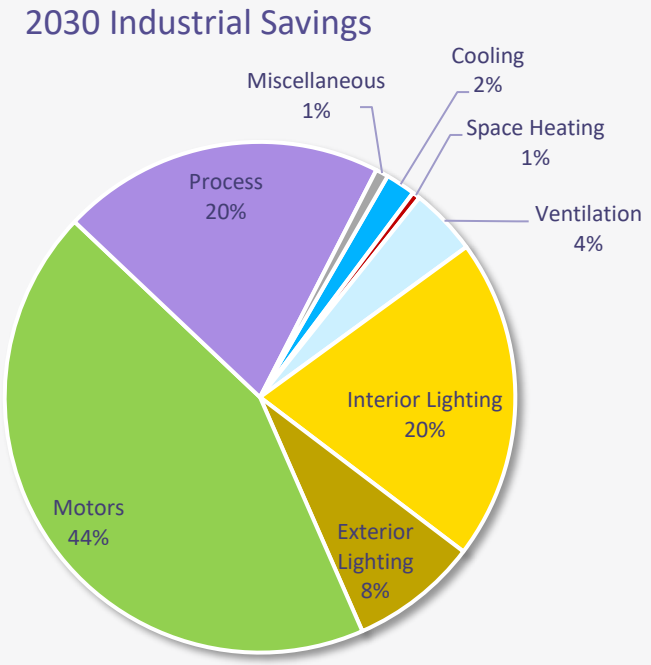




Industrial Top Measures – Achievable Potential

Industrial Sector

- Linear and High-Bay includes savings incorporate lighting control technologies



Rank	Measure	Achievable Potential in 2025	Achievable Potential in 2030	% of Total
1	Linear Lighting	3,522	11,241	14.6%
2	High-Bay Lighting	2,738	8,482	11.0%
3	Strategic Energy Management	3,302	7,725	10.0%
4	Pumping System - Controls	1,765	7,188	9.3%
5	Refrigeration - Floating Head Pressure	2,081	5,083	6.6%
6	Fan System - Controls	1,167	4,802	6.2%
7	Refrigeration - High Efficiency Compressor	1,483	3,643	4.7%
8	Retrocommissioning	3,747	3,567	4.6%
9	Switch from Belt Drive to Direct Drive	844	3,380	4.4%
10	Refrigeration - System Optimization	1,242	3,004	3.9%
11	Compressed Air - End Use Optimization	703	2,875	3.7%
12	Fan System - Equipment Upgrade	629	2,610	3.4%
13	Material Handling - Variable Speed Drive	609	2,452	3.2%
14	Ventilation	276	2,385	3.1%
15	Compressed Air - Variable Speed Drive	100	1,181	1.5%
16	Exterior Lighting - Retrofit - Enhanced Controls	507	966	1.3%
17	Pumping System - Variable Speed Drive	234	941	1.2%
18	Fan System - Variable Speed Drive	206	848	1.1%
19	Process - Tank Insulation	53	595	0.8%
20	Pumping System - Equipment Upgrade	140	561	0.7%
	Total Top 20 Measures	**25,348**	**73,527**	**95.3%**
	Total Measures	**26,306**	**77,135**	**100.0%**

IRP Inputs


FINANCIAL REPORT
NEWS
3.45 2.58 6.58 12.3
9.42 3.56
7.42 8.52 6.47
5.42 0.58 6.02
9.42 3.56 7.43

Modeling Energy Efficiency Potential within the IRP

The EE Potential Assessment identifies the EE opportunities in PNM's service territory through 2042

Energy efficiency measures can be considered on par with supply-side resources based on their availability, hourly impacts, cost, and life.

- Program potential is the best representation of energy efficiency's likely effect on loads and resource needs, however:
  - HB 291 savings targets only run through 2025 with guidance to establish targets through 2029
  - The 2023-2025 EE Program Potential is already screened for cost-effectiveness, so does not allow the IRP to consider higher-cost energy efficiency measures based on changing resource needs

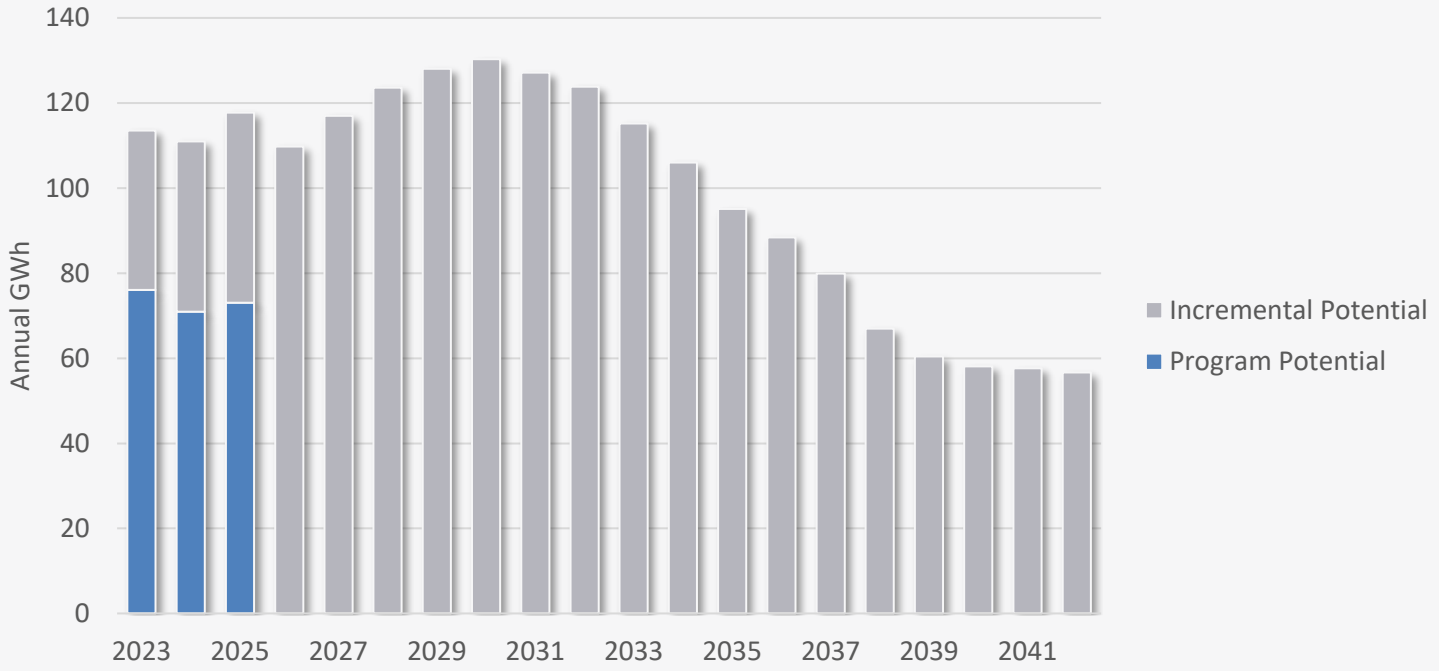
To enable modeling energy efficiency as a resource within the IRP, AEG developed hourly supply curves representing program potential and additional opportunities not deemed cost-effective within the potential study

AEG Supply Curve Bundling Methodology

Step 1: Calculate "achievable technical" potential, incorporating achievability rates, but not cost-effectiveness screening.

Step 2. Identify measure-level incremental potential beyond statutory goals

- **2023 – 2025:** Incremental Potential = Achievable Technical − Program Potenital
- **2026 – 2040:** Incremental Potential = Achievable Technical



AEG Supply Curve Bundling Methodology (Continued)

Step 3. Define bundles based on levelized cost of conserved energy. Levelized costs are in 2021$

Step 4. Match energy efficiency measures to resource bundles and calibrated load shapes.

- AEG assigned each measure in the potential study to a bundle in each year based on
  - a) whether it was included in the program potential, and
  - b) its levelized cost.
- Each measure was similarly matched to a calibrated load shape by building type and end use.

Step 5. Calculate annual incremental energy savings and weighted average cost and measure life for each bundle based on included measures.

Step 6. Develop hourly impacts for each bundle by spreading measure-level impacts over calibrated end use load shapes

Updated Bundle Breakpoints

Updated bundling scheme groups more low-cost measures together and provides additional granularity in the cost range that is likely to be more marginal within the IRP model

Previous Study

Statutory Period 2021-2025	Post-Statutory Period 2026-2040
Program Potential	n/a
Up to $50/MWh[1]	Up to $5/MWh
	$5/MWh to $15/MWh
	$15/MWh to $25/MWh
	$25/MWh to $35/MWh
	$35/MWh to $50/MWh
Over $50/MWh	Over $50/MWh

Initial Current Study

Statutory Period 2023-2025	Post-Statutory Period 2026-2042
Program Potential	Program Potential
Up to $50	Up to $50
$50 and Up	$50 to $75
	$75 to $100
	$100 to $125
	$125 to $150
	$150 and Up

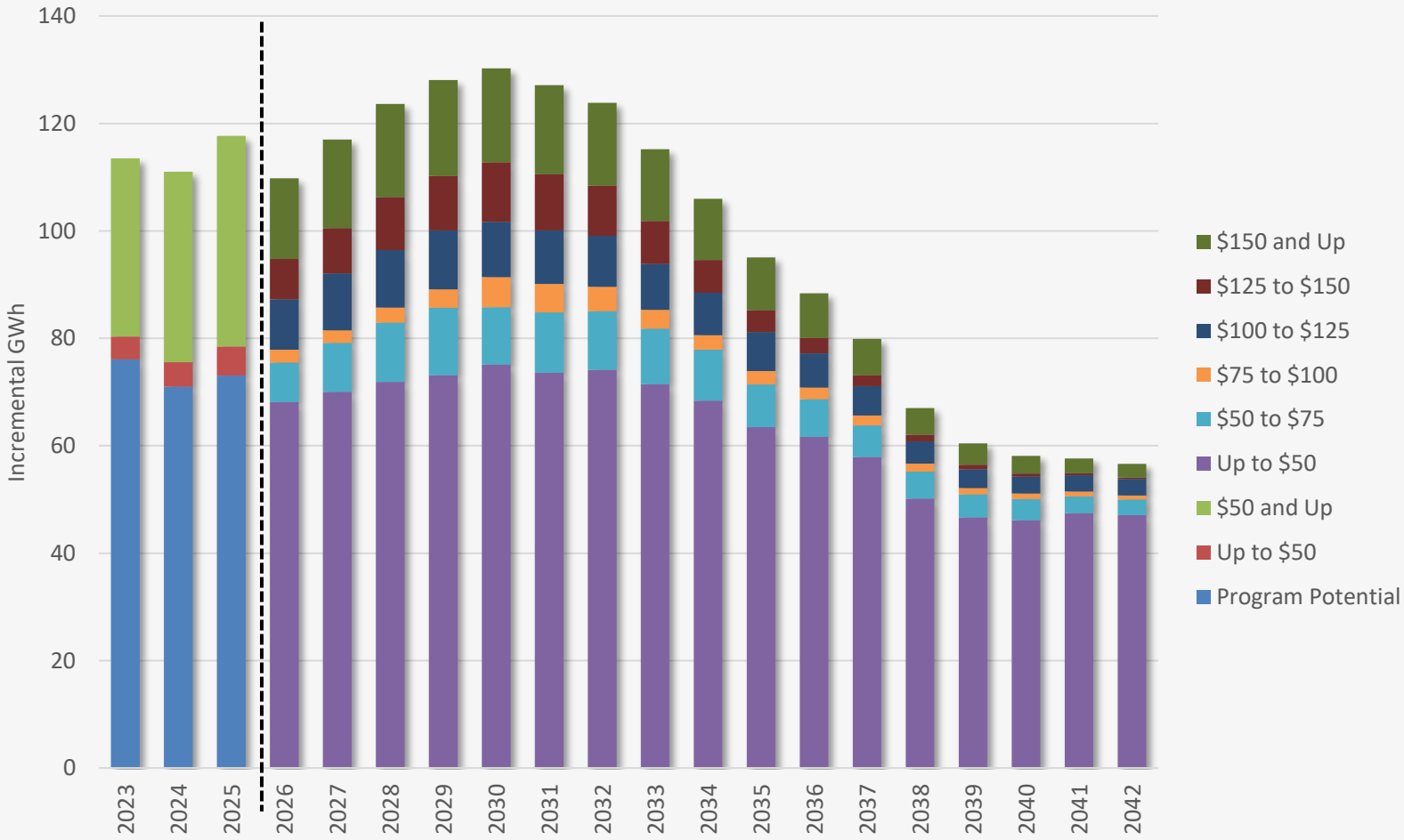
Annual Incremental Energy Savings per Bundle

2023-2025

- In 2023 – 2025 the average cost of the program bundle is $17/MWh.
- Capturing almost all the potential up to $50

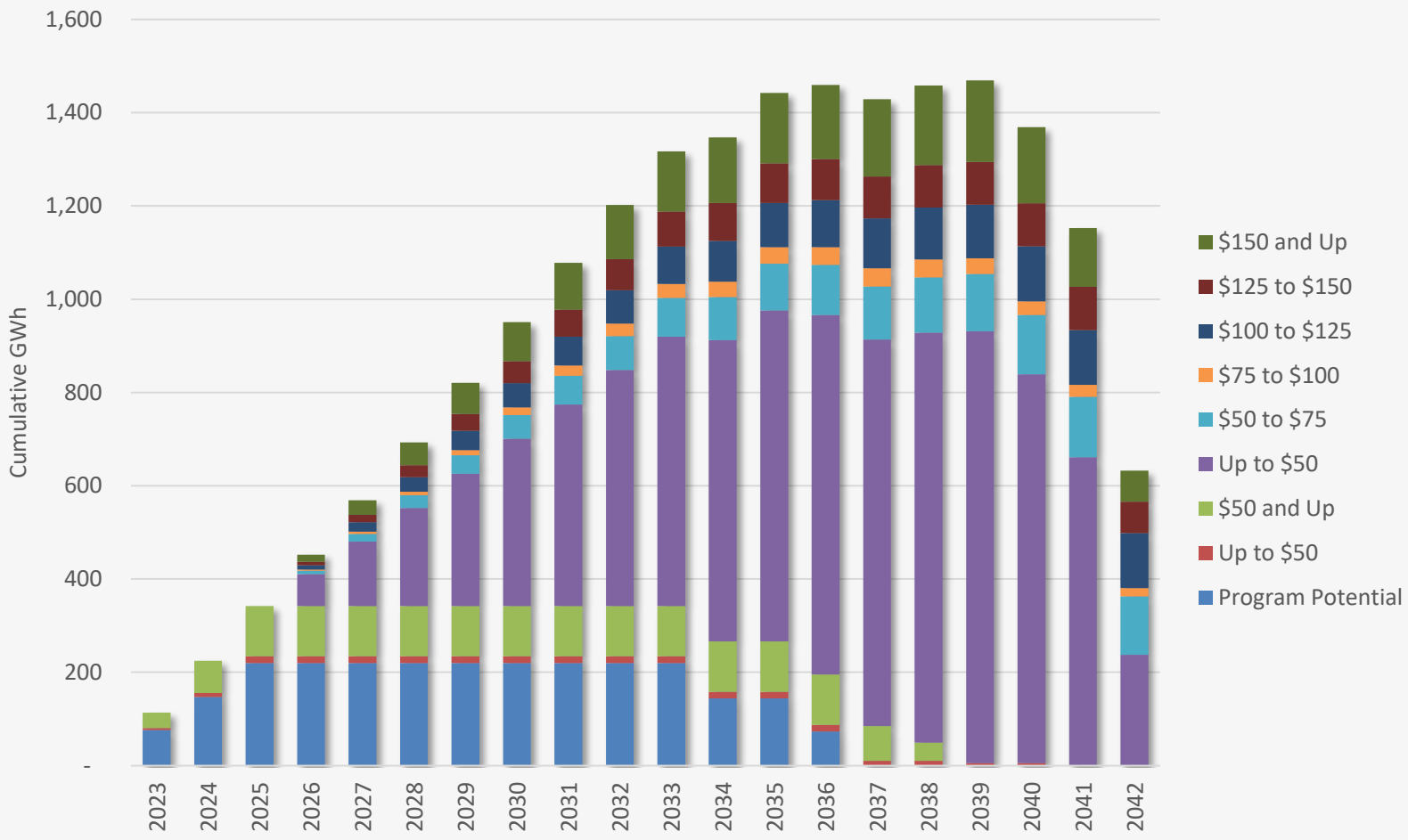
2026-2042

- Most of the potential still falls in the “up to $50” bundle, especially in the out years
- The more expensive buckets are primarily made up of HVAC & more expensive lighting measures
- After 2036, as we approach market saturation, incremental installations and savings begin to level off or decrease relative to previous years



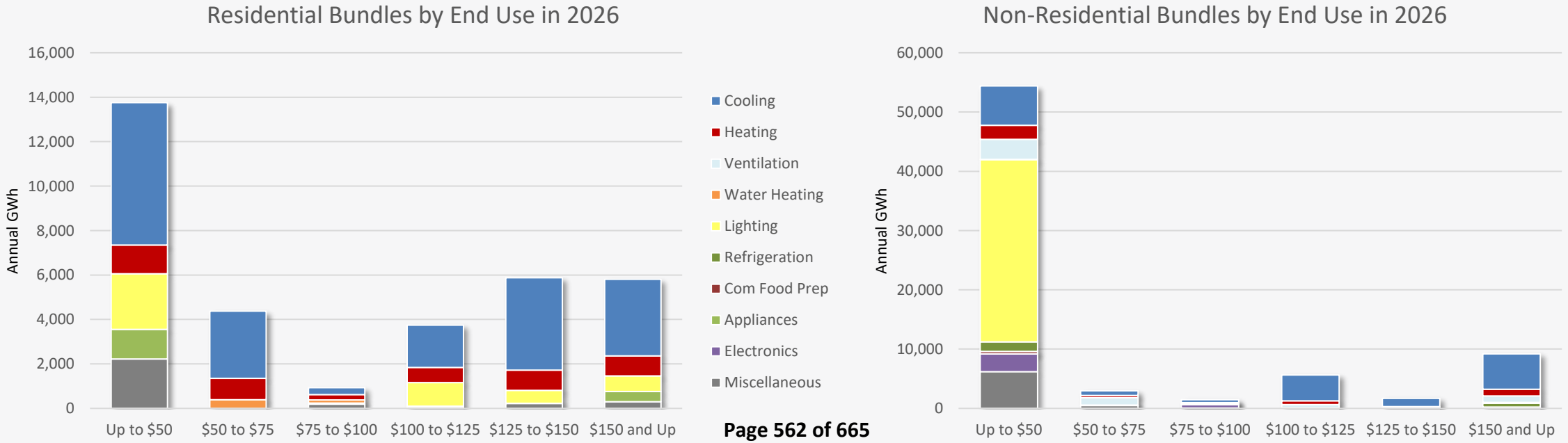
Cumulative GWh by Bundle

Cumulative Savings by average measure life in each bundle.



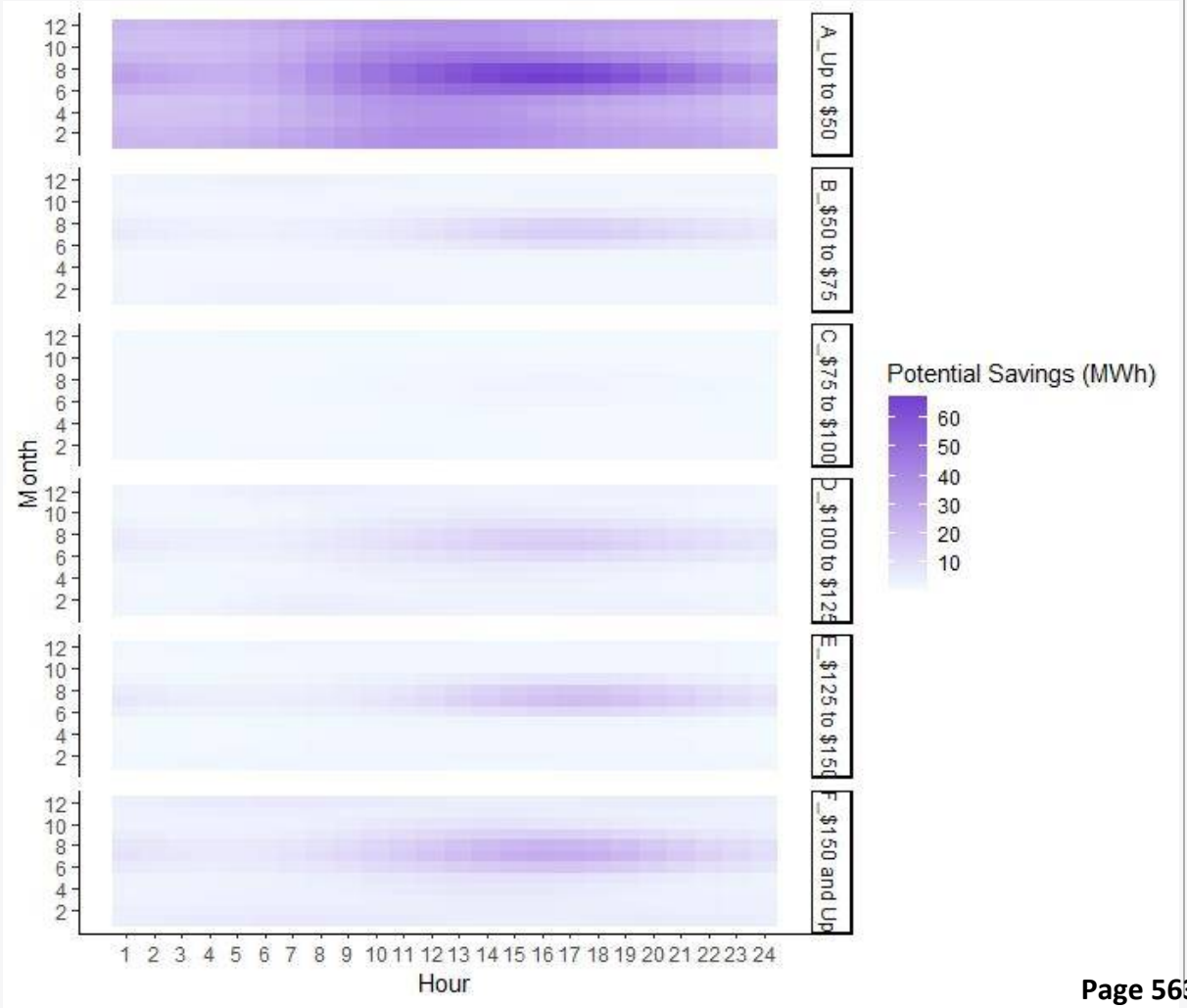
Bundles by End Use

- Majority of savings fall into the “Up to $50” bundle
  - Correlates to the Program bundle from the 2023-2025 Statutory period
- Residential lighting savings are a smaller portion of savings than in previous study due to new EISA backstop provision
  - Non-Residential lighting savings come LED replacements for Linear Lighting and High-Bay Lighting

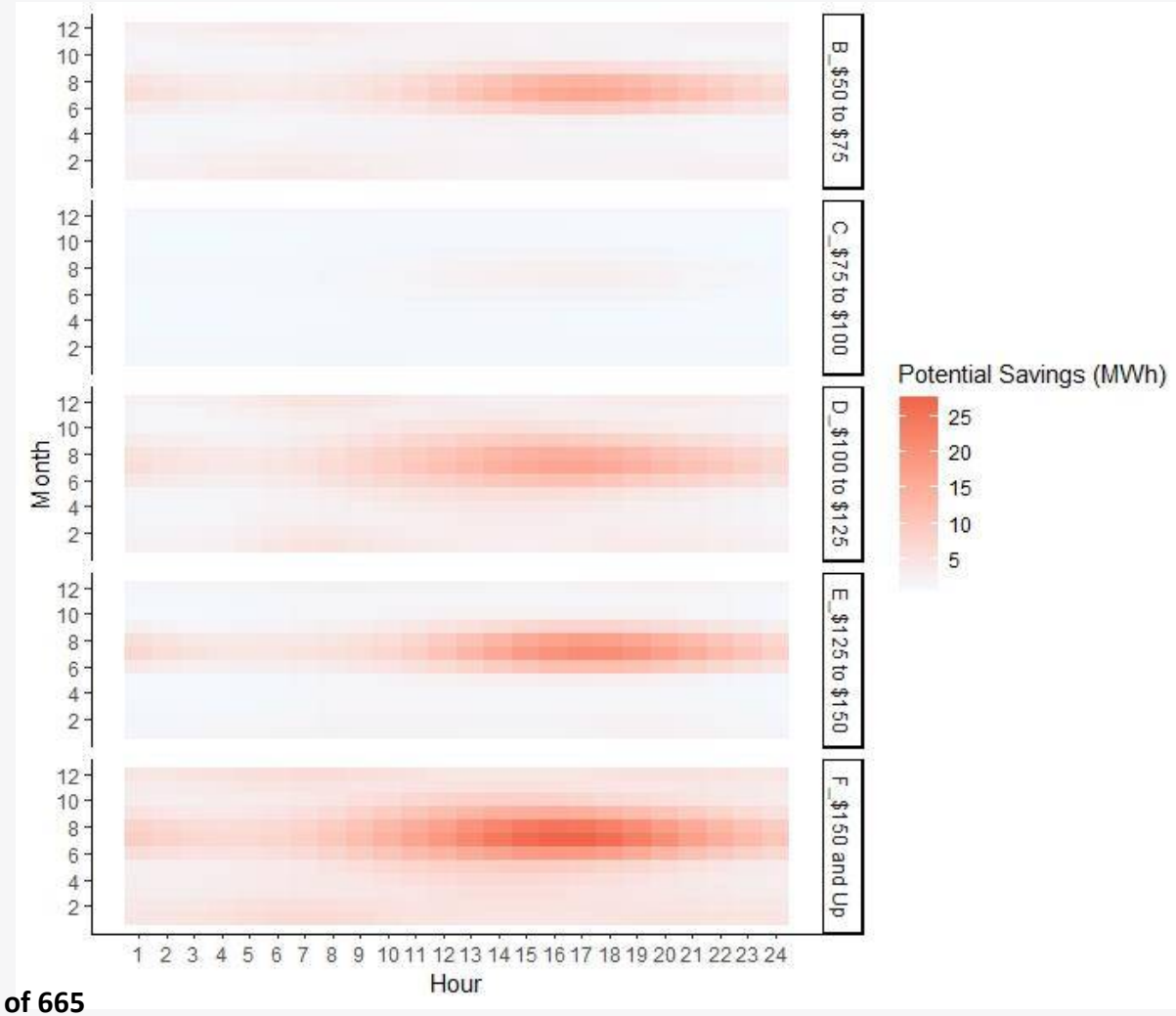


2026 Hourly Savings by Bundle

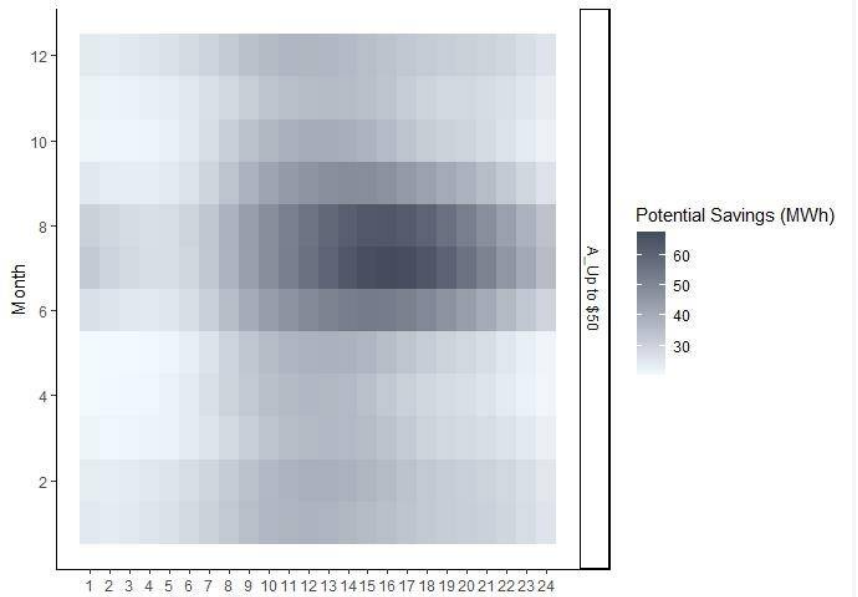
All Bundles

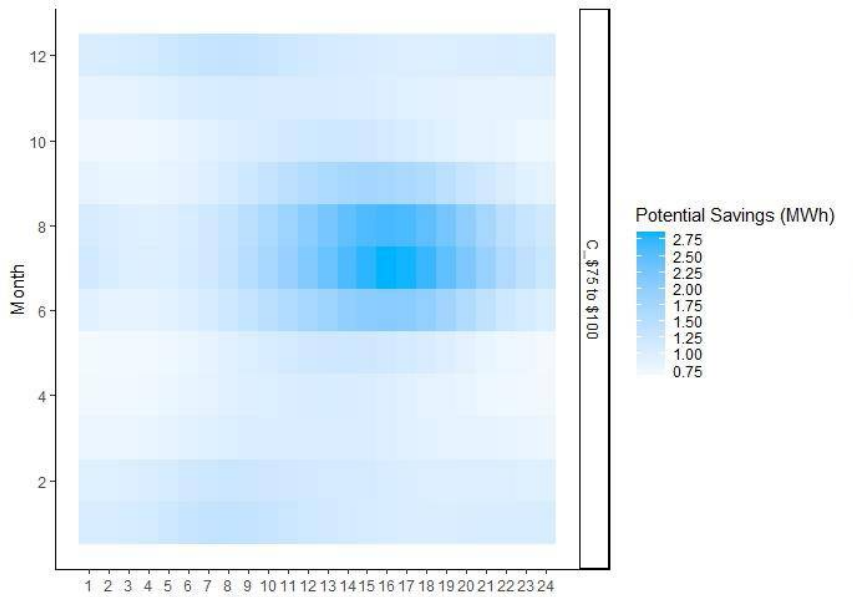


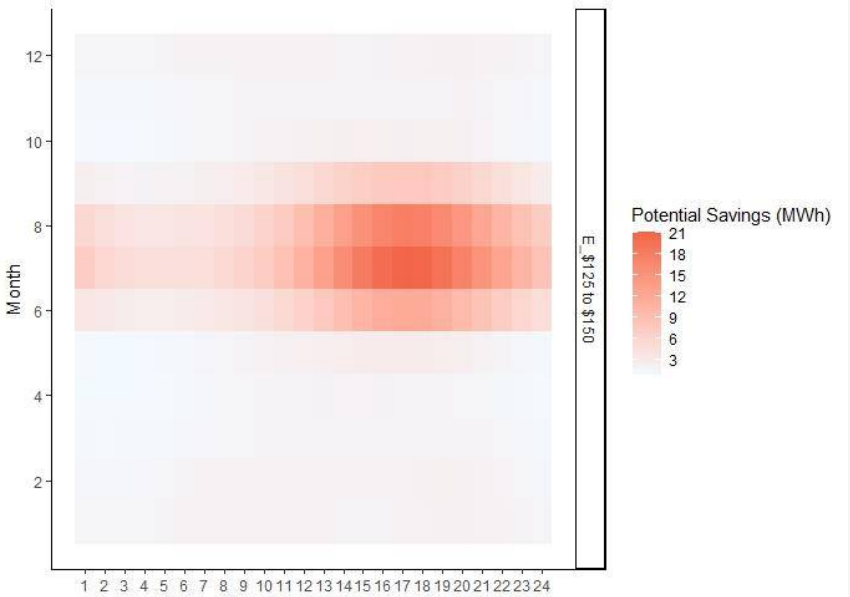
Excluding "$Up to 50" Bundle

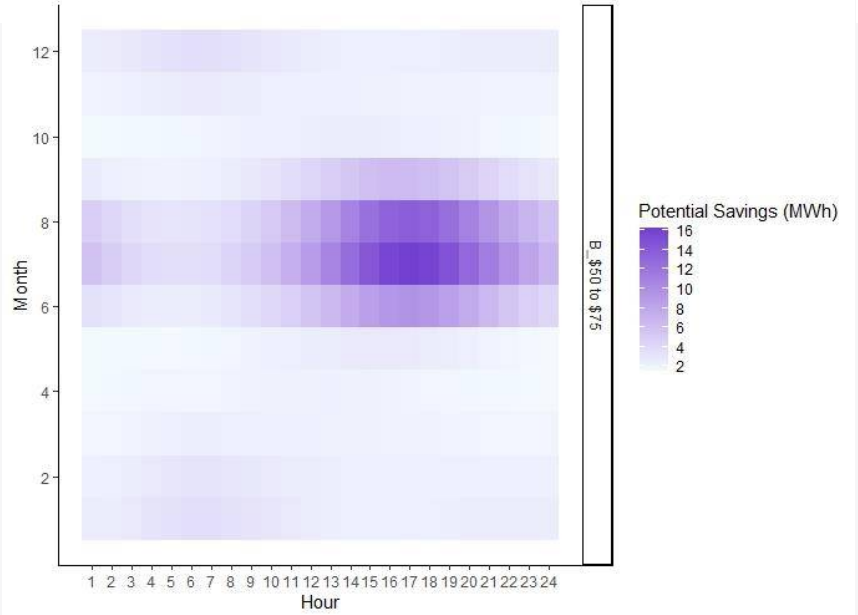


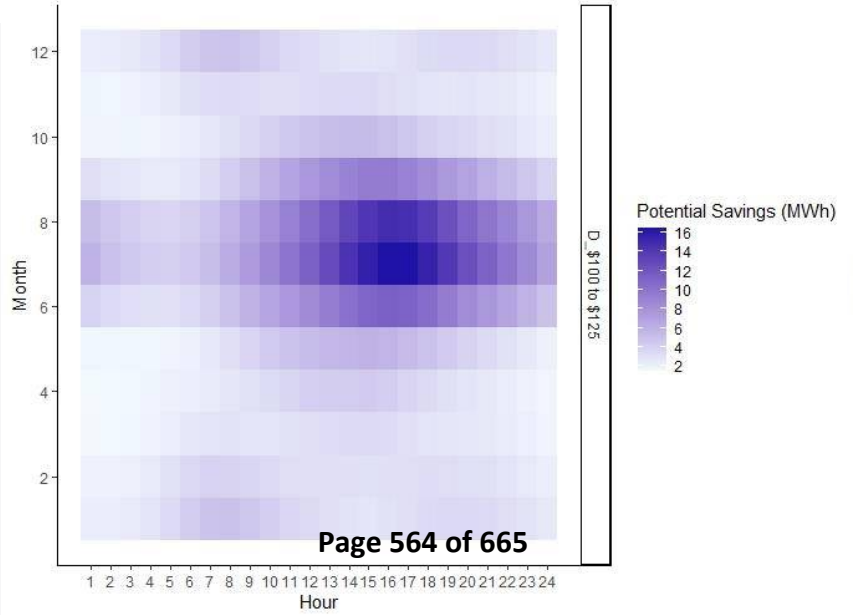
2026 Hourly Savings by Bundle

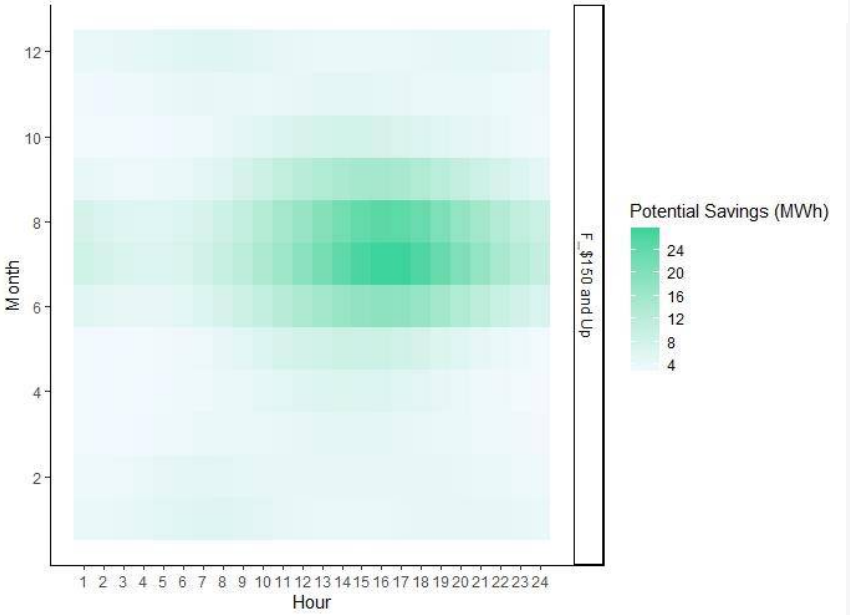




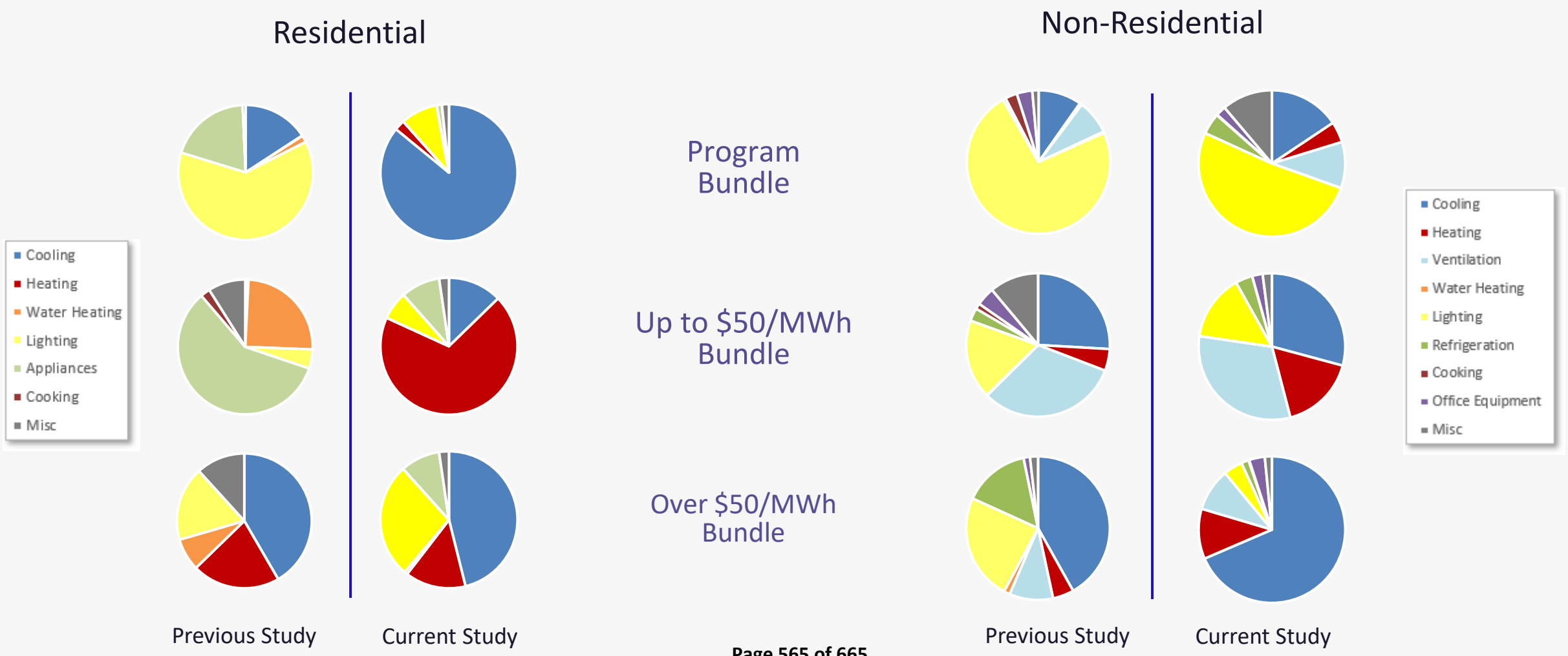








Comparison to Previous Study



Comments or Questions?



Thank You.

Phone: 631-434-1414

AEG
APPLIED ENERGY GROUP

PNM Energy Efficiency – Program Highlights

RESIDENTIAL PROGRAMS

- Cooling:
  - A/C tune-up
  - “Midstream” (distributor and HVAC contractor incentives)
- Home Energy Checkups (Assessment, DI measure Installation and rebates)
- Refrigerator Recycling
- Residential Retail Products (non-lighting and lighting measures)
- New Home Construction (builder incentives)
- Home Energy Reports behavioral program
- School Education Kit programs (targeting 5th grade and high school students)
- Income Qualified programs:
  - IQ Home Energy Checkup (Assessment, DI measure installation, free refrigerator replacement if eligible)
  - NM Mortgage Finance Authority (weatherization and retrofit)
  - Easy Savings mailed “kit” (self-install lighting, weatherization measures, etc.)

COMMERCIAL PROGRAMS

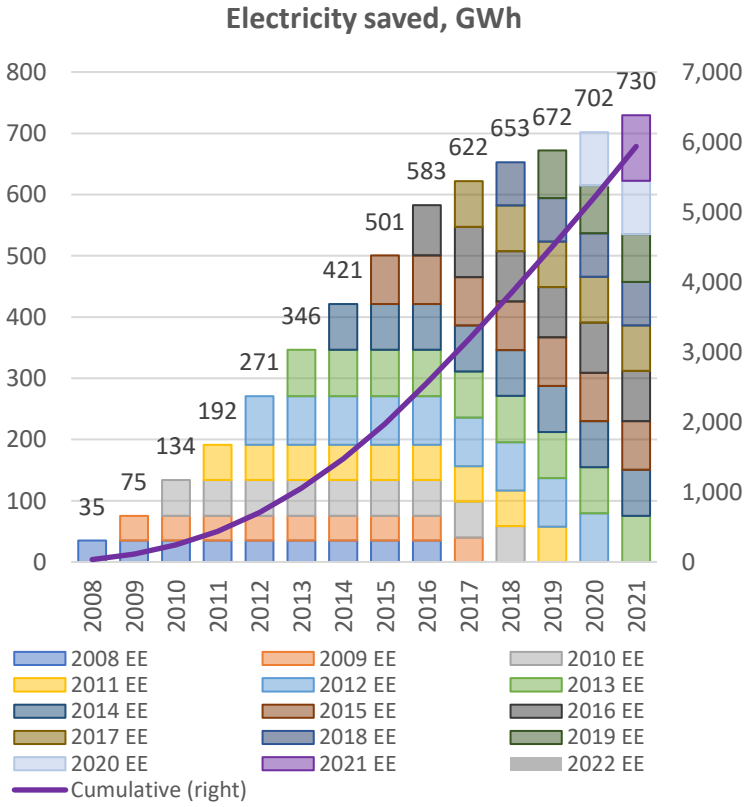
- Small Commercial Direct Install
- New Construction (offering incentives for installing/designing more efficient construction) than code standards
- Building retrofits
    - Rebates for specific measures
        - Lighting
        - Cooling
        - Custom measures
- “Midstream” offering equipment distributors incentives for measures such as cooling, cooking, lighting, etc.
- Strategic Energy Management Behavioral Program

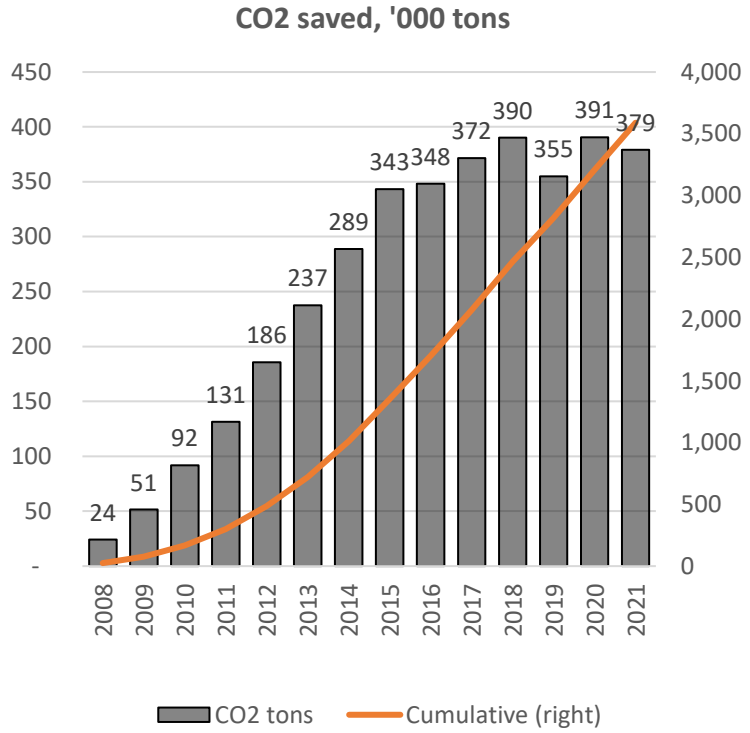
DEMAND RESPONSE

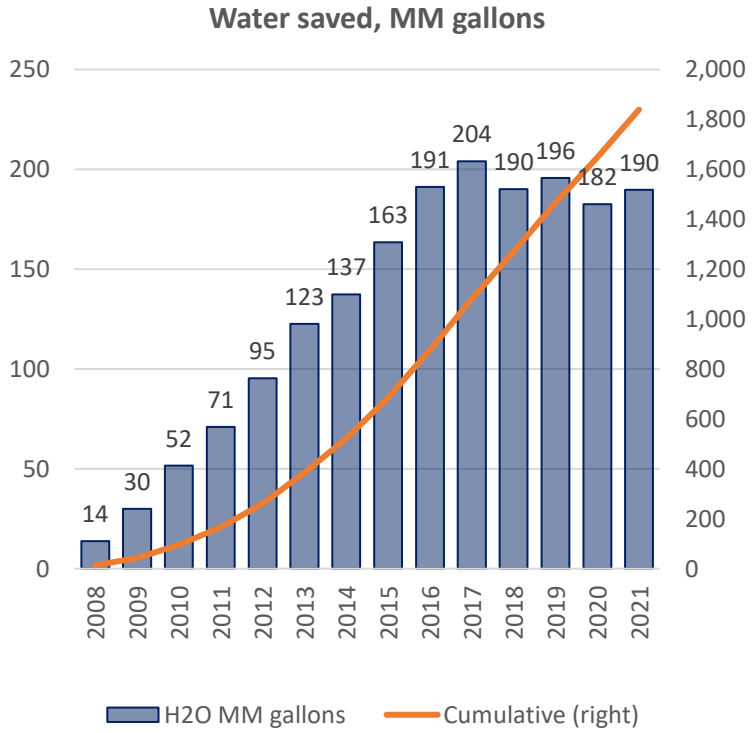
- PNM's demand response (DR) programs were first offered to customers in 2007
- Over the last 12 years, Power Saver and Peak Saver have developed into a reliable and cost effective alternative peaking resource
- The programs deliver about 55 MW of non-spinning reserve capacity during the four summer months of June – September

EE SAVINGS AND ACHIEVEMENTS

- PNM began offering Energy Efficiency programs in late 2007
- Currently on track to achieve 2025 EUEA savings goal







Talk to us.

PNM Resource Adequacy Near Final Results Stakeholder Meeting

Astrapé Consulting

January 17, 2023

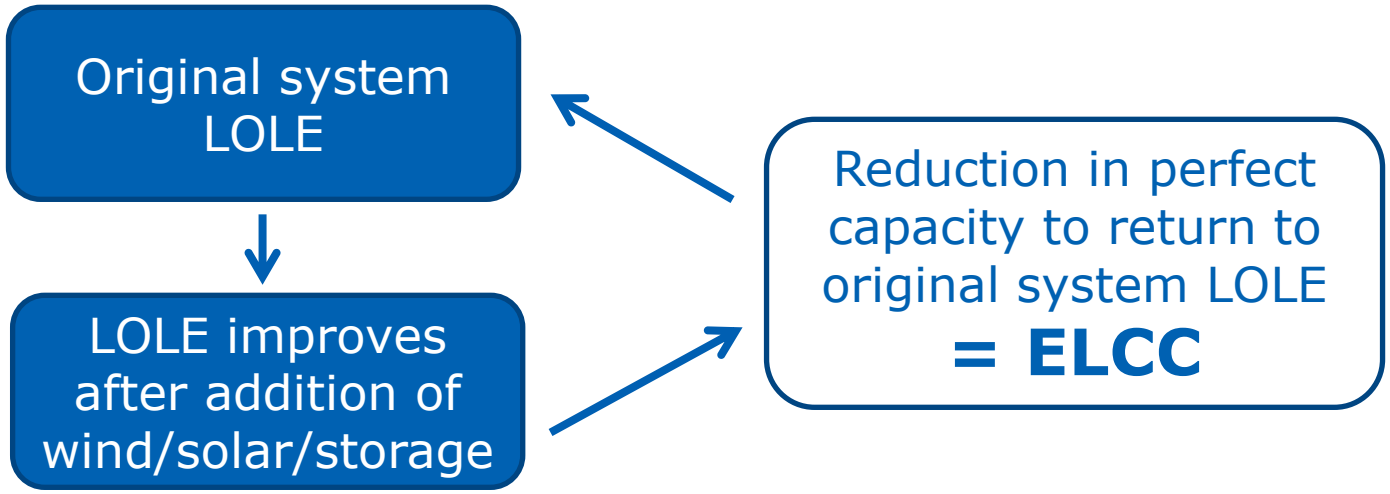
ASTRAPÉ CONSULTING
innovation in electric system planning

Future Resource ELCC Analysis Update

ASTRAPÉ CONSULTING
innovation in electric system planning

Defining ELCC

- Effective load carrying capability (ELCC) is the quantity of 'perfect capacity' that could be replaced or avoided with wind, solar, storage, etc. while providing equivalent system reliability



- ELCC is the most rigorous method for calculating qualifying capacity of energy-limited resources (solar, wind, storage, etc.)

Key Assumptions

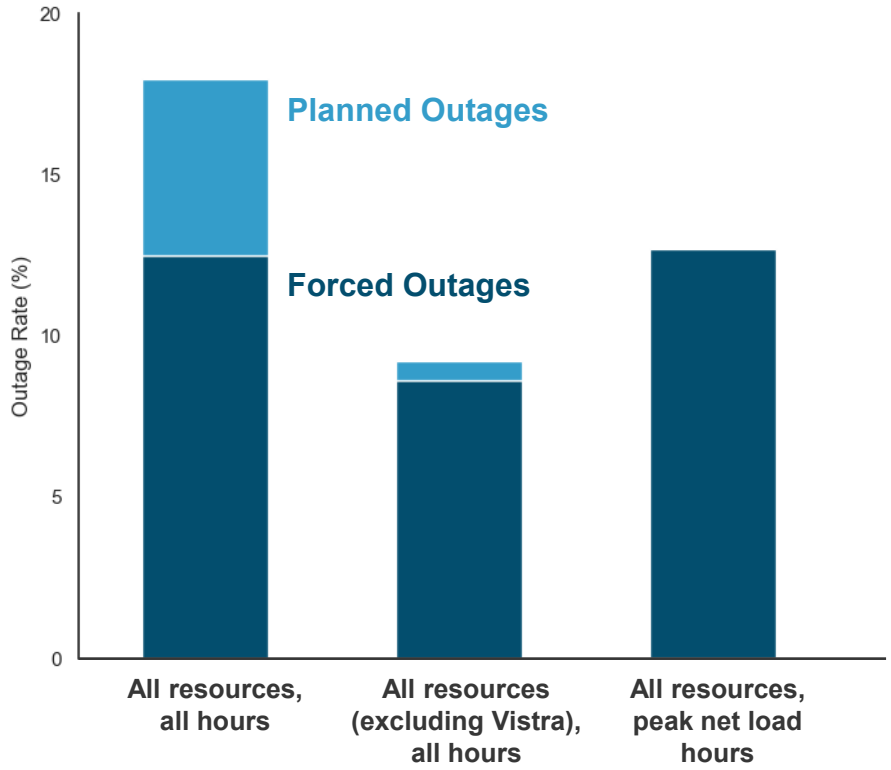
- **Neighbor Assumptions**
  - Based on recent SW E3 study data
  - Public ERP and IRP data for PSCO and SPS
  - 50 MW import limit during peak periods
  - Impacts PNM existing solar accreditation
- **2025 storage, wind, and solar assumptions**
  - 650 MW of battery
  - 607 MW of Wind
  - 1,531 MW of Solar
- **Battery Outage Rates – modeled at 92% availability**
  - Based on E3 study of California battery operation

Utility-Scale Battery Outage Rates in California

+ **Over the past year, installed capacity of energy storage on CAISO system has increased from approximately 2 to 4 GW**
  - Daily outage reports published by CAISO provide insight into how often those resources have been available to serve loads
+ **Outage data from Oct 1, 2021 - Sept 30, 2022 analyzed under three filters:**
  - **All resources, all hours:** how has the entire CAISO storage fleet performed over the past year?
  - **All resources (excluding Vistra), all hours:** to what extent does the large extended outage at the Vistra facility affect the numbers?
  - **All resources, peak net load hours:** how well have storage resources performed during the most critical periods for reliability?
+ **Preliminary takeaways from the data:**
  - Operational data set is still small enough that outliers can significantly skew results
  - Roughly 10% of storage capacity has consistently been offline due to forced outages (excluding Vistra from sample)
  - During the tightest periods on the grid, planned outages are limited, but forced outage rates for storage facilities have approached 15%

Planned and Forced Outage Rates Observed Among CAISO Energy Storage Resources

Oct 1, 2021 – Sept 30, 2022



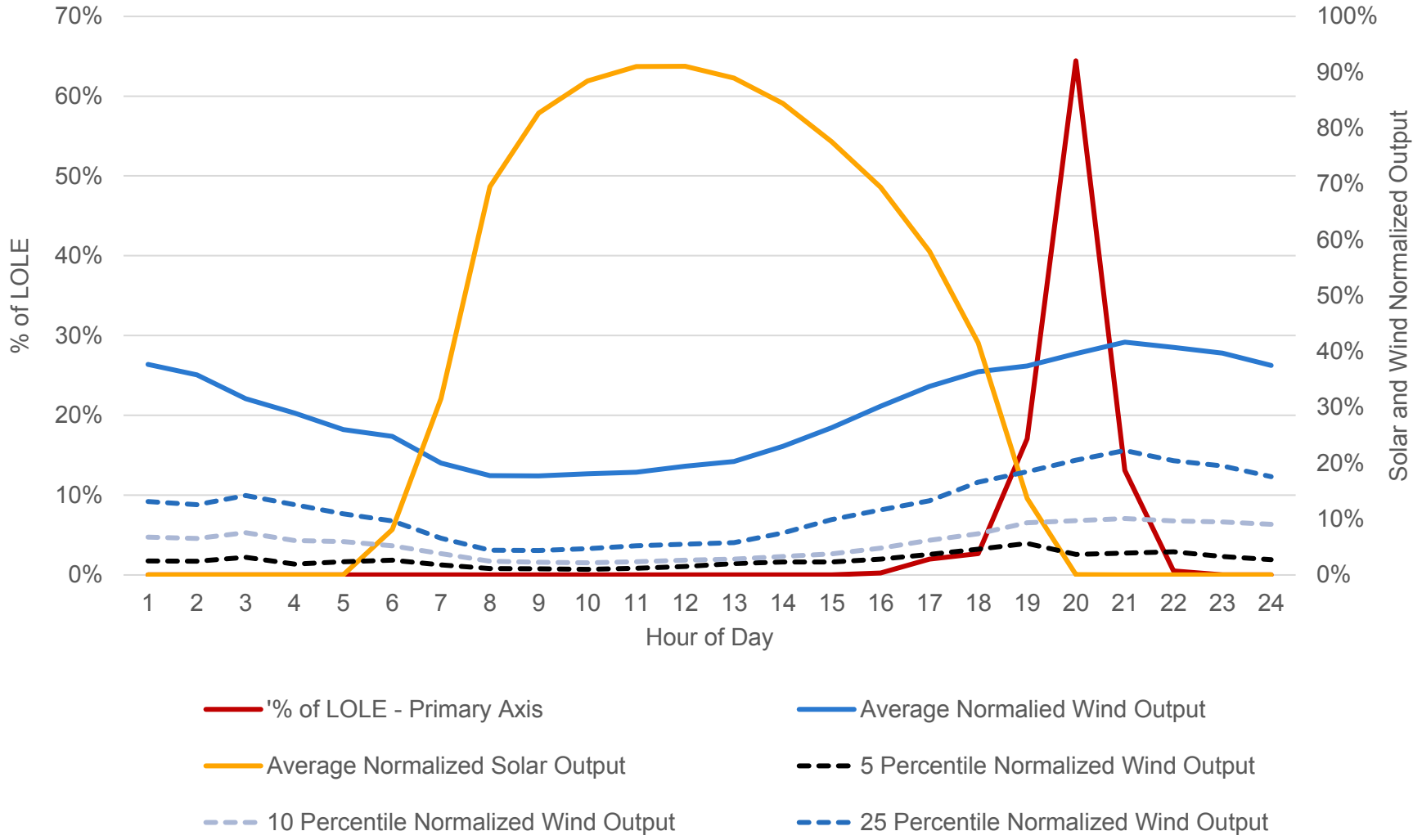
Notes:
Data analyzed based on one-year period from October 1, 2021 to September 30, 2022
"Peak net load hours" defined as the highest four hours of net load on the five days with highest net loads (all occurred in early Sept 2022)

Resource Adequacy Risk by Hour of Day



ASTRAPÉ CONSULTING
innovation in electric system planning

Resource Adequacy Risk With 2025 Renewable Shapes



Renewables Shapes are represented with July Data

ASTRAPÉ CONSULTING
innovation in electric system planning

Surface Creation

- **To capture the ELCC values of incremental storage, solar, and wind resources we created surfaces of results for combinations of the three variables.**
- **The table below highlights what combinations were run in SERVM for total storage values of 650 MW, 850 MW, 1,250 MW, and 1,650 MW.**

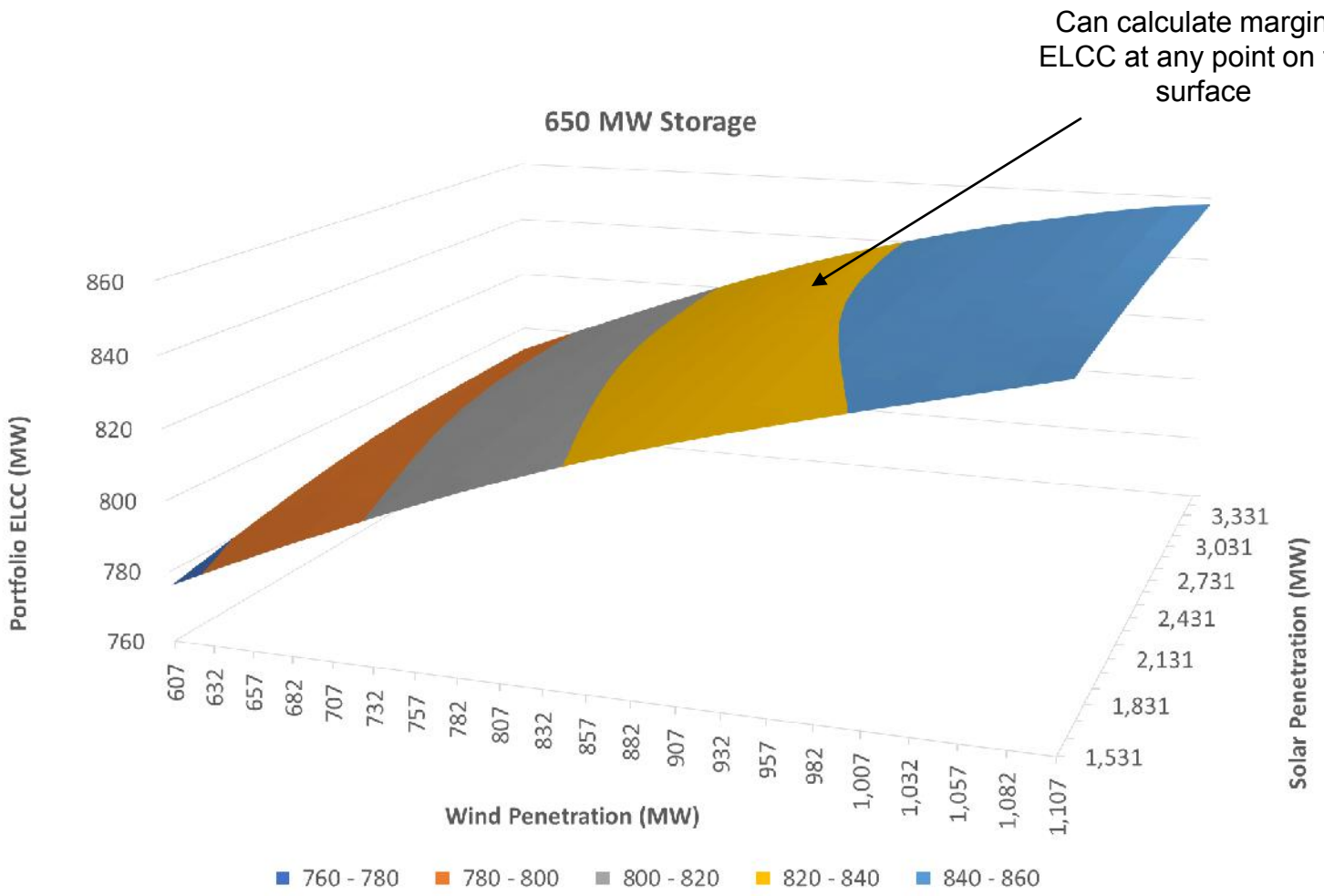
Solar and Wind ELCC at xxx MW Storage						
	Wind (MW)					
Solar (MW)	607	707	807	907	1007	1107
1531	x		x		x	
1931		x		x		x
2331	x		x		x	
2731		x		x		x
3131	x		x		x	
3531		x		x		x

ASTRAPÉ CONSULTING
innovation in electric system planning

Surface Creation

- **Created Surfaces using SERVM results and smoothing algorithms.**
- **The surfaces provide the ability to calculate marginal ELCC for any of the three technologies at any combination within the ranges simulated**
  - Storage 650 MW – 1,650 MW
  - Solar 1,531 MW –3,531 MW
  - Wind 607 MW – 1,107 MW

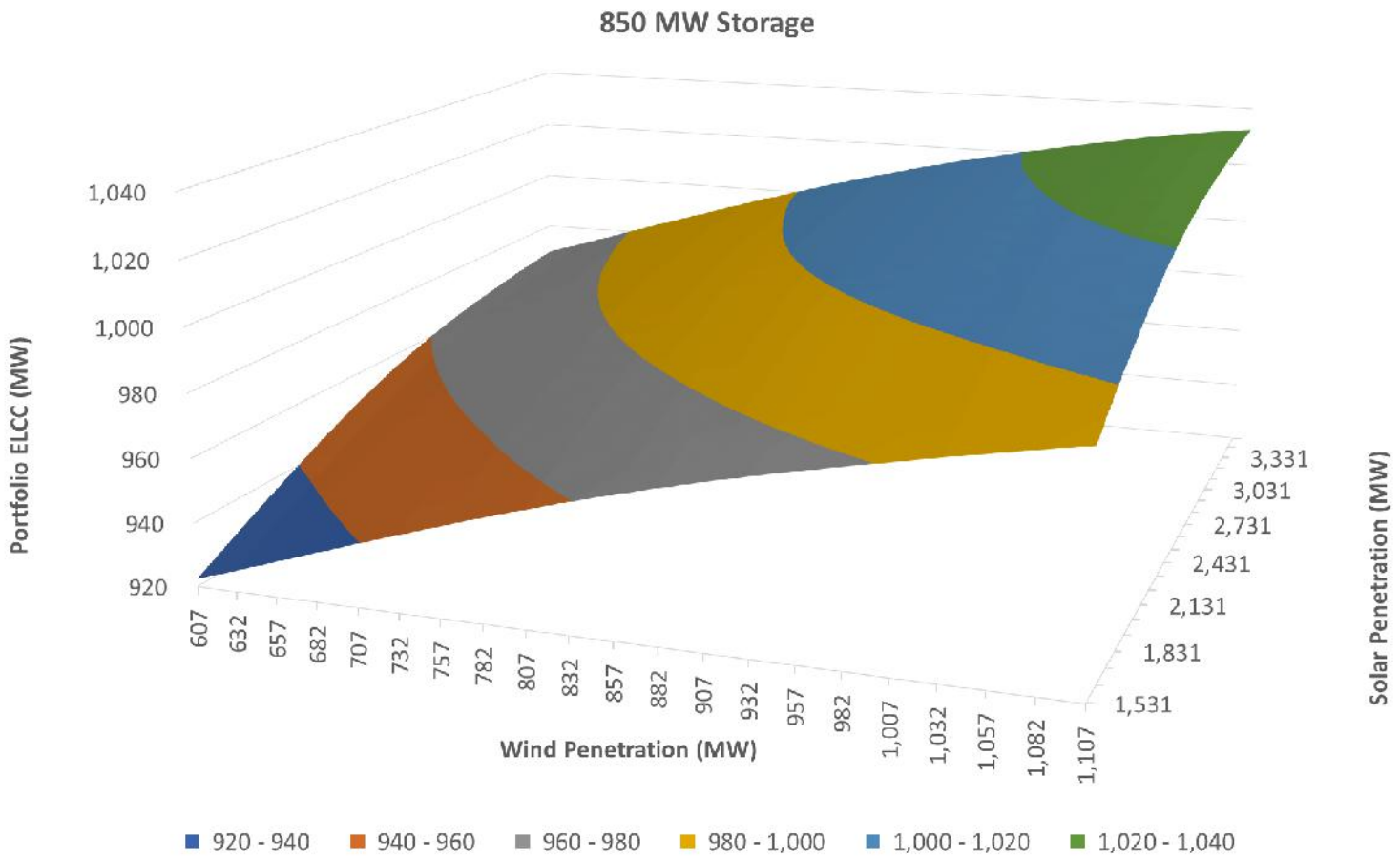
Updated Surfaces



Near-final results

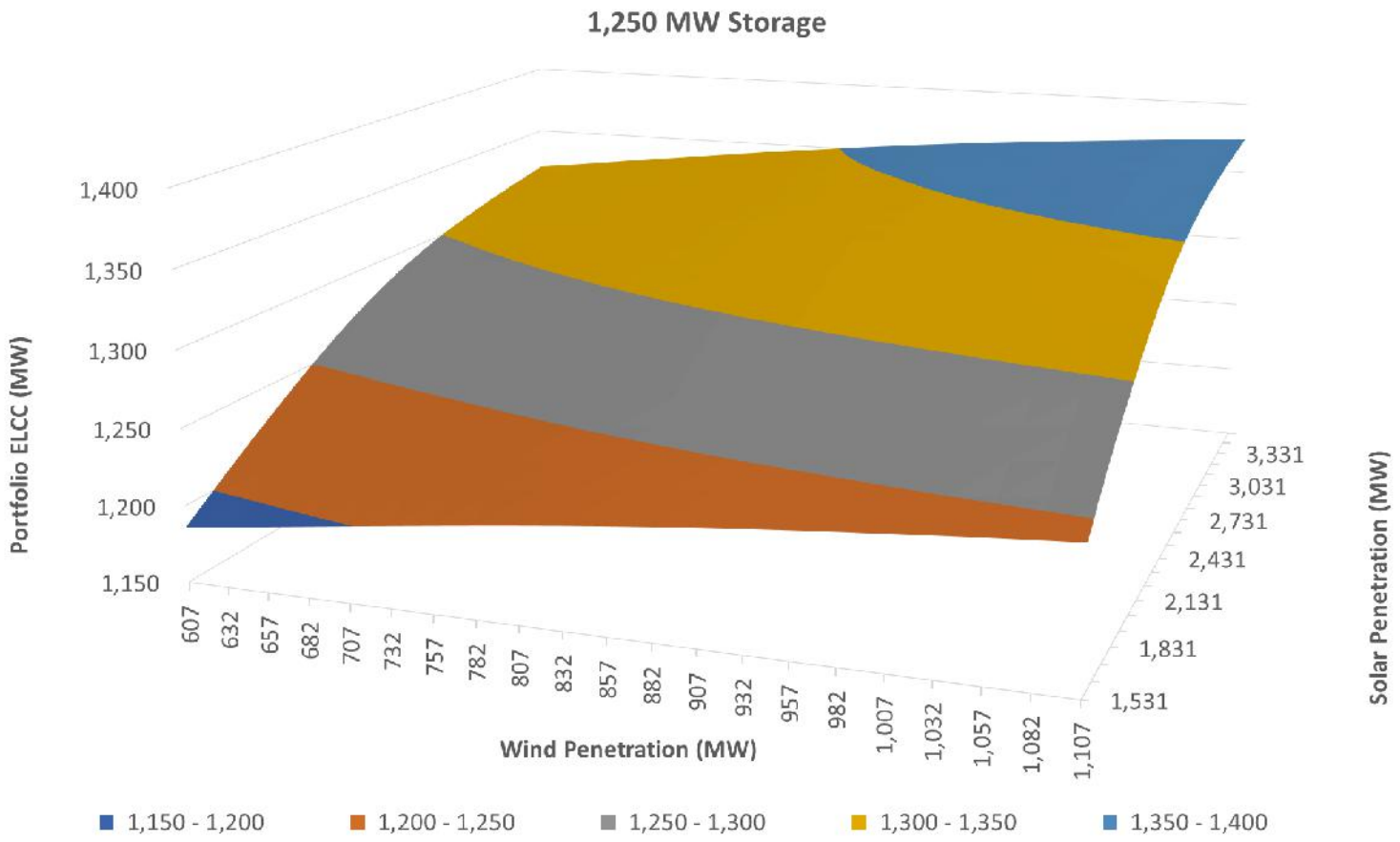
ASTRAPÉ CONSULTING
innovation in electric system planning

Updated Surfaces



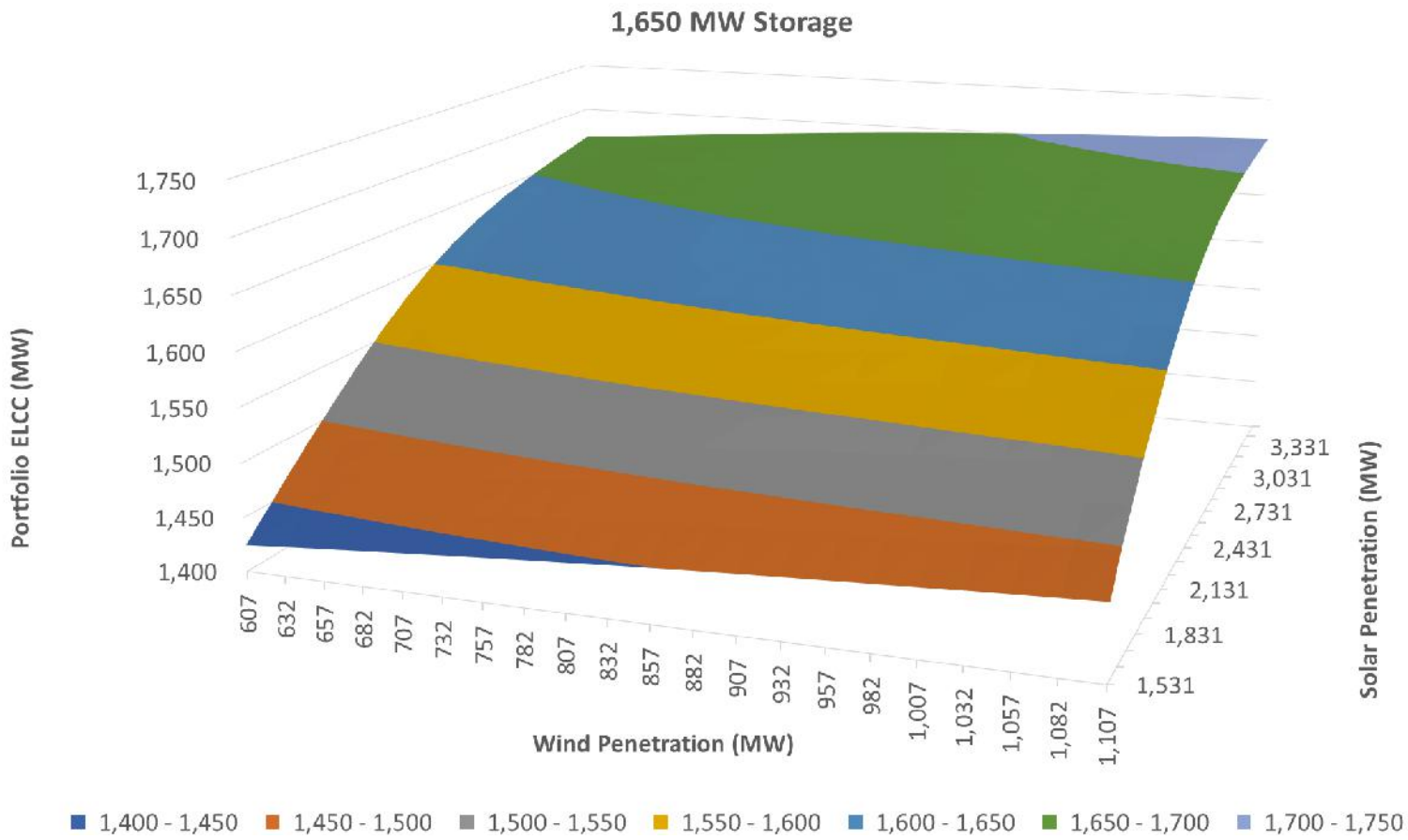
Near-final results

Updated Surfaces



Near-final results

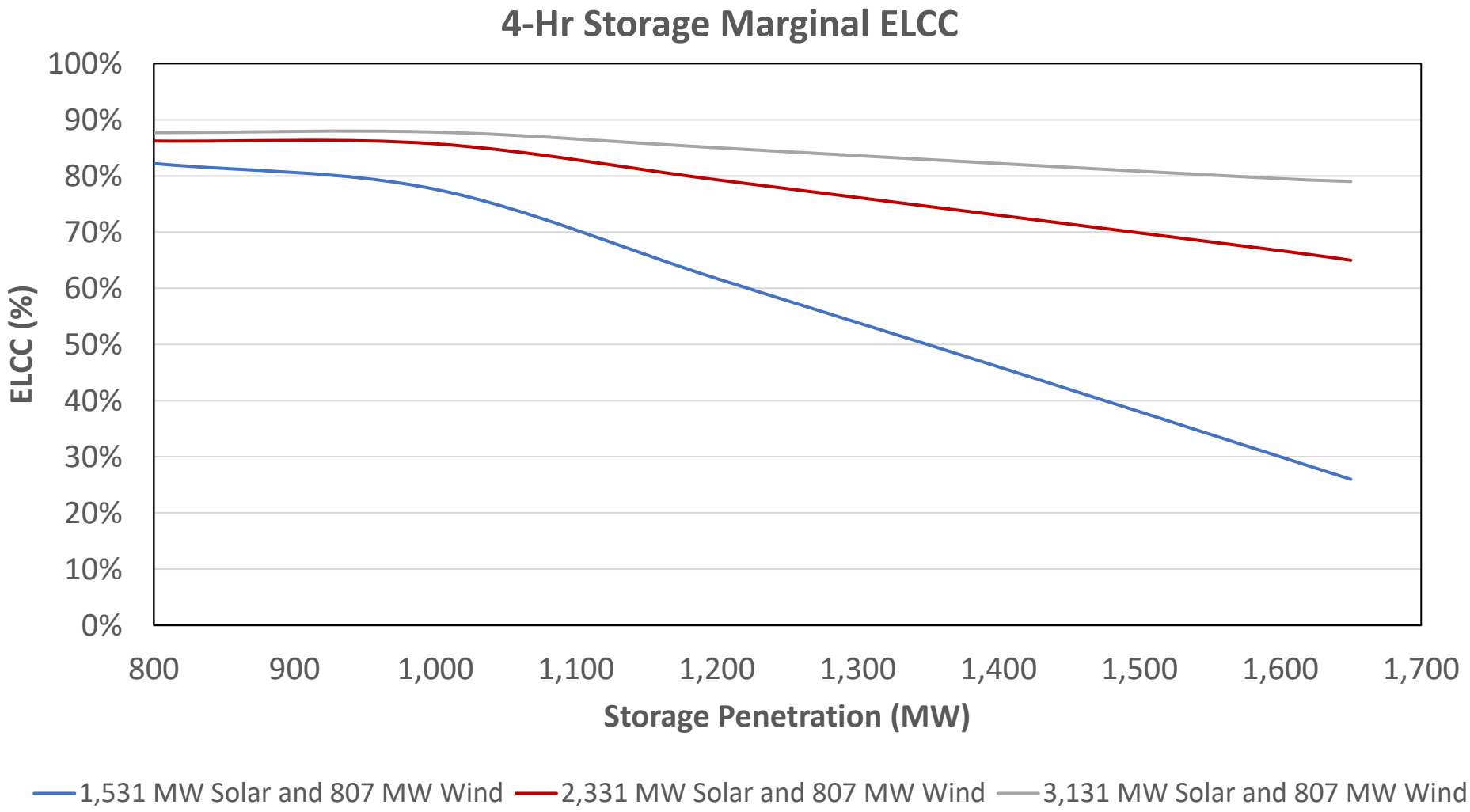
Updated Surfaces



Near-final results

ASTRAPÉ CONSULTING
innovation in electric system planning

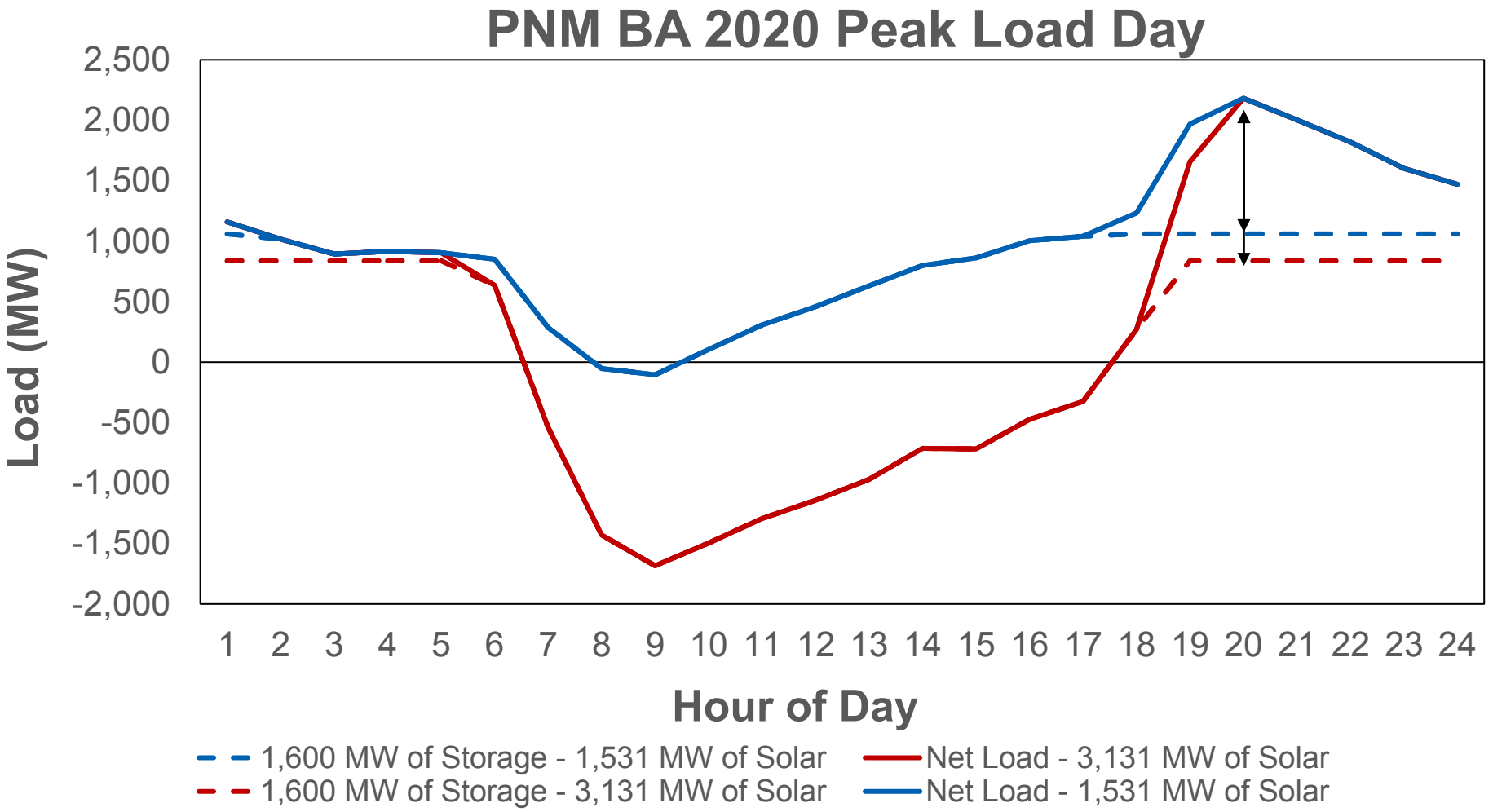
Marginal ELCCs: 4-Hr Storage



Near-final results

ASTRAPÉ CONSULTING
innovation in electric system planning

Net Load Shape Analysis – 1,600 MW of Storage under 2 Solar Scenarios

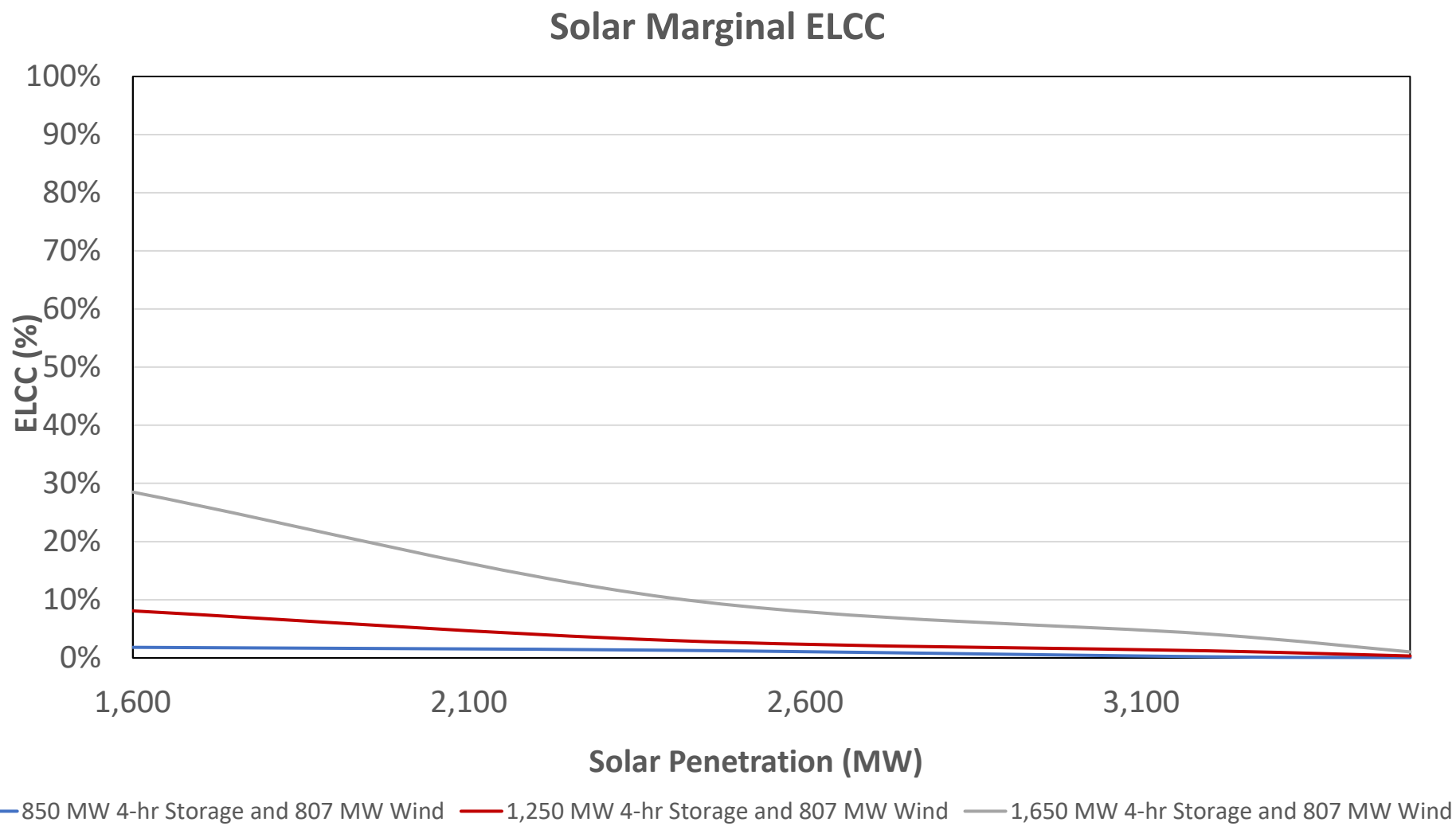


Near-final results

Charging not shown on chart but 1,600 MW of storage sees charging constraints in the baseline solar case

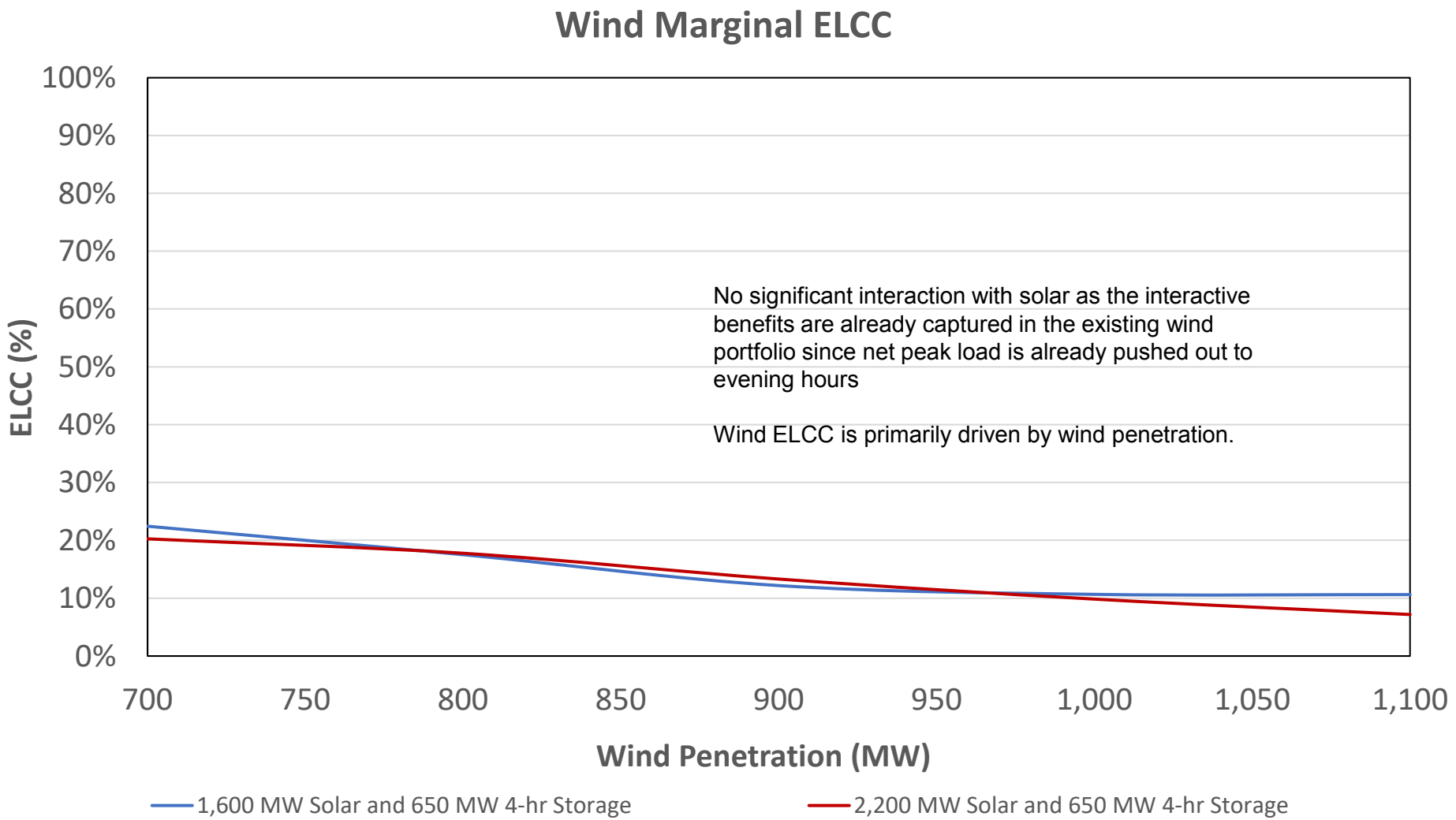
ASTRAPÉ CONSULTING
innovation in electric system planning

Marginal ELCCs: Solar



Near-final results

Marginal ELCCs: Wind



Near-final results

8-HR Sensitivity Results

4-hr and 8-hr Battery ELCC Comparison		
Initial 4-hr Storage Capacity (MW)	200 MW Incremental 4-hr ELCC (%)	200 MW Incremental 8-hr ELCC (%)
650	86%	88%
850	85%	87%
1,050	82%	85%
1,250	81%	82%
1,450	65%	79%
1,650	Not simulated	69%

Results include 2,331 MW of solar
ELCC values represent the incremental 200 MW block in addition to the initial 4-hour storage level.

Near-final results

2035 ELCC Sensitivity

- **Direct comparisons to 2025**
- **Slightly less value in 2035 due to higher renewable and storage values in neighboring regions**

Incremental Storage (MW)	Incremental Solar (MW)	Incremental Wind (MW)	2025 Incremental ELCC (MW)	2035 Incremental ELCC (MW)	Delta (MW)
650	-	-	469	452	(17)
650	-	300	509	495	(14)
650	-	500	517	504	(13)
650	1,200	-	540	519	(21)
650	1,200	300	593	572	(21)
650	1,200	500	607	580	(27)

Near-final results

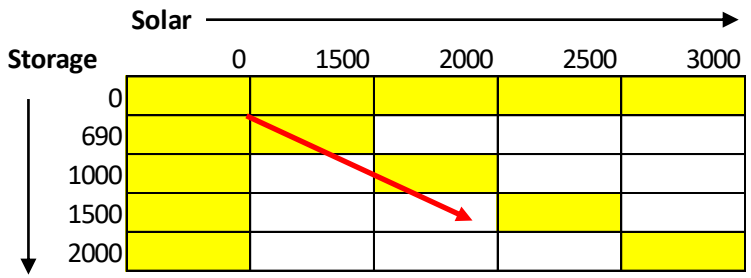
ASTRAPÉ CONSULTING
innovation in electric system planning

Initializing the ELCC Trajectory

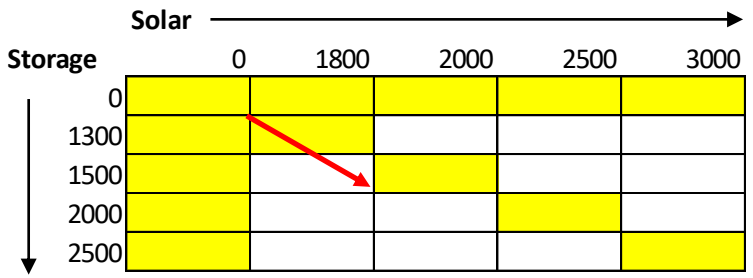
Installed Capacity – PVNGS NNC

Sum of Capacity (MW)	Column Labels																			
Row Labels	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal:Conventional	697	697	200	200																
Demand:Distributed Generation	33	48	48	15	15	15	15	15	15	15		15	15	15	15	15	15	15	15	15
Demand:Energy Efficiency	20	39	60	83	107	114	121	128	134	141	148	155	142	130	117	124	107	90	92	95
Gas/Oil:Combined Cycle	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	
Gas/Oil:Combustion Turbine	416	416	416	416	416	416	416	416	267	267	267	267	267	267	267	267	267	267	267	126
Gas/Oil:Steam Turbine	146	146	146	146	146	146	146	146	146	146										
Nuclear:Nuclear	402	402	298	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288
Renewable:Geothermal	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Renewable:Solar PV	378	1025	1521	1687	1771	1755	1743	1732	1720	1709	1698	1686	1675	1664	1663	1723	1713	1701	1770	3080
Renewable:Wind	658	658	658	658	658	658	658	658	658	658	658	658	658	658	556	556	556	556	556	956
Storage:Battery		300	590	690	846	937	959	1129	1136	1136	1304	1304	1320	1341	1382	1395	1421	1449	1569	2390

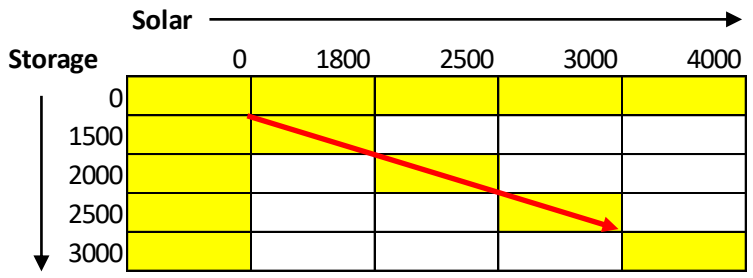
2025 Study Year — **Use 2025 - 2031**



2032 Study Year — **Use 2032 - 2039**



2040 Study Year — **Use 2040-2043**



- **Evaluate resources individually**
- **Evaluate resources as a portfolio**
- **Appropriately allocate synergistic benefit**

Note this is a two-dimensional illustrative example

ASTRAPÉ CONSULTING
innovation in electric system planning

Questions

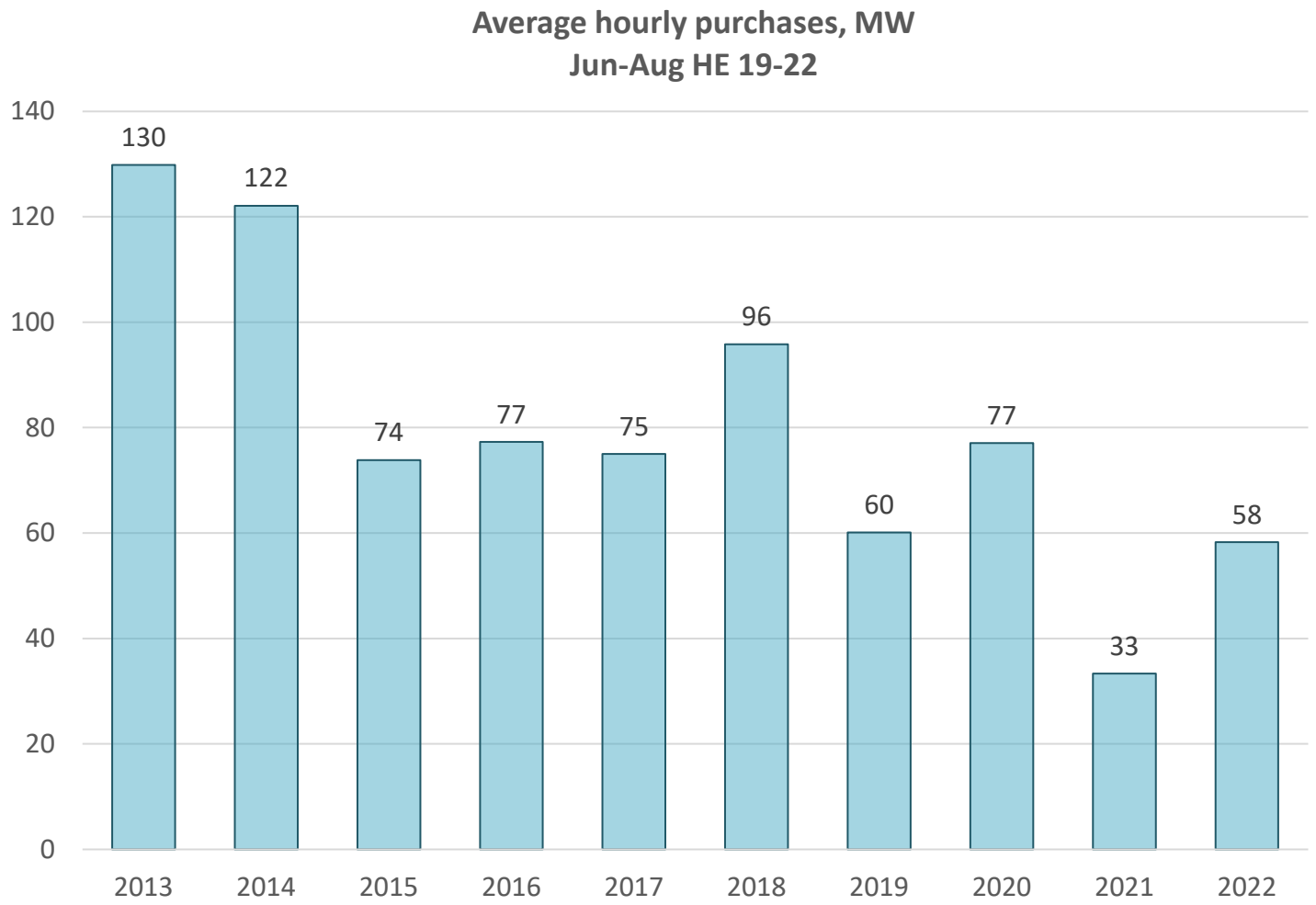
ASTRAPÉ CONSULTING
innovation in electric system planning

PNM Summer 2022 Review and Modeled Market Assistance for Resource Adequacy

INTRODUCTION TO SUMMER 2022 DISCUSSION

- In our previous discussion of market dynamics and system resiliency, PNM mentioned meeting after summer 2022 to review new data and modeled market assistance included for resource adequacy
- Modeled Market Assistance included for Resource Adequacy are currently same as in PV Replacement Case and 2020 IRP; SERVM allows for sharing based on economics and transmission constraints in all hours except for the following constraints:
    - Limited to 200-300 MW in all hours when load is greater than 85% of the gross peak load
    - Summer (June – August) evening net peak load hours:
        - Limit to 100-150 MW for hours 16-18 when load is greater than 85% of gross peak load
        - Limit to 50 MW for hours 19-22 from June to August when hourly gross load is greater than 80% of the gross peak load
            - 80% of gross load during hours 19-22 ensures this limit occurs on peak load days
- In the 2020 IRP, these limitations reduced internal planning reserve margin by 5% in a no-imports case (island)

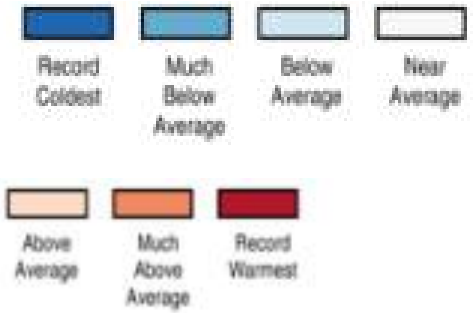
MARKET PURCHASES DURING HIGH-RISK WINDOW



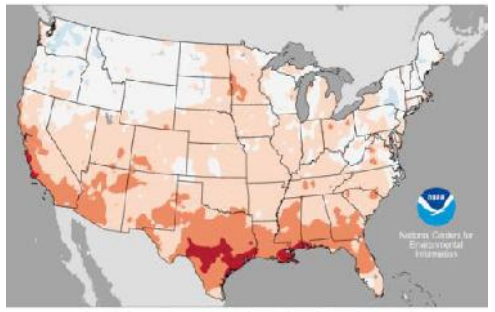
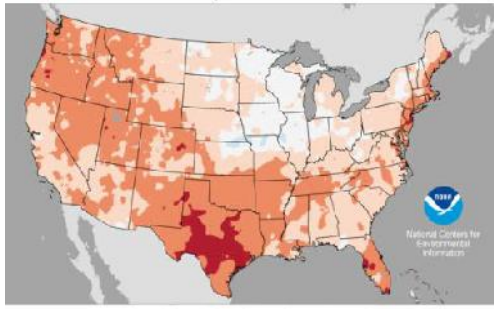
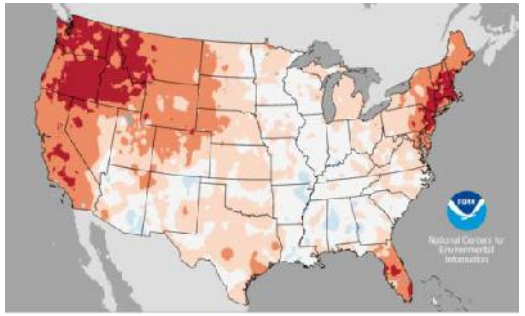
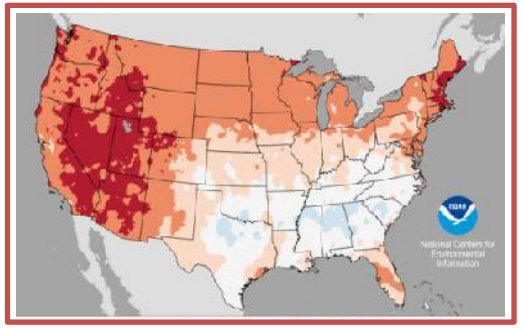
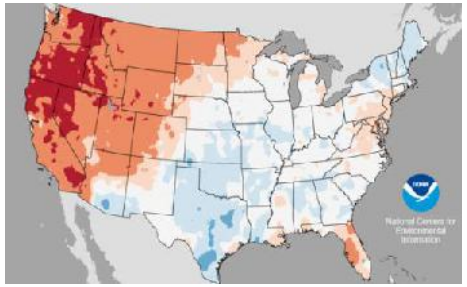
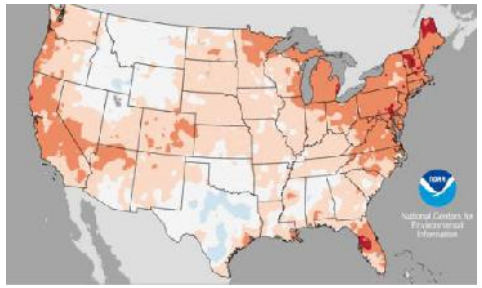
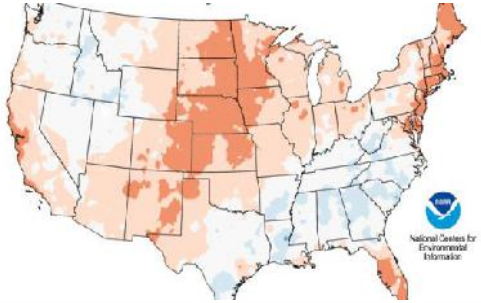
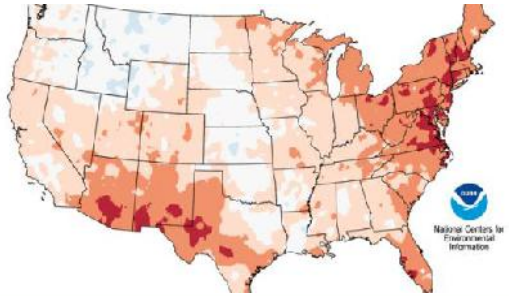
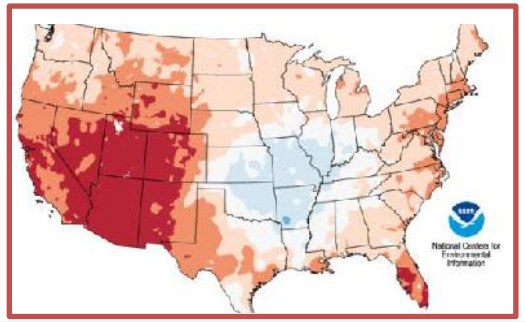
- Summer 2022 did not see a regional heat wave comparable to prior summers, in addition, thermal units had solid availability
- As the Southwest region sees more solar and storage additions, LOLE risk is increasingly concentrated in the non-solar hours 19-22
- Over time, ability to purchase from market during risk hour window has decreased over time
- Going forward, online capacity in risk hours will increasingly be made up of energy-limited resources
- PNM expects market liquidity to worsen in the most constrained hours as risk hours and resource mixes align across the Southwest region (E3 SWRA Study, presented in the May 25 IRP PAG meeting)
- While ability to purchase during high net load hours was greater in 2022 than in prior years, planning should take these growing risks into consideration

REGIONAL WEATHER DYNAMICS WERE NOT AS EXTREME IN 2022 AS IN PRIOR YEARS

Mean Temperature Percentiles



Source: NOAA National Centers for Environmental Information
Ranking period: 1895-2022

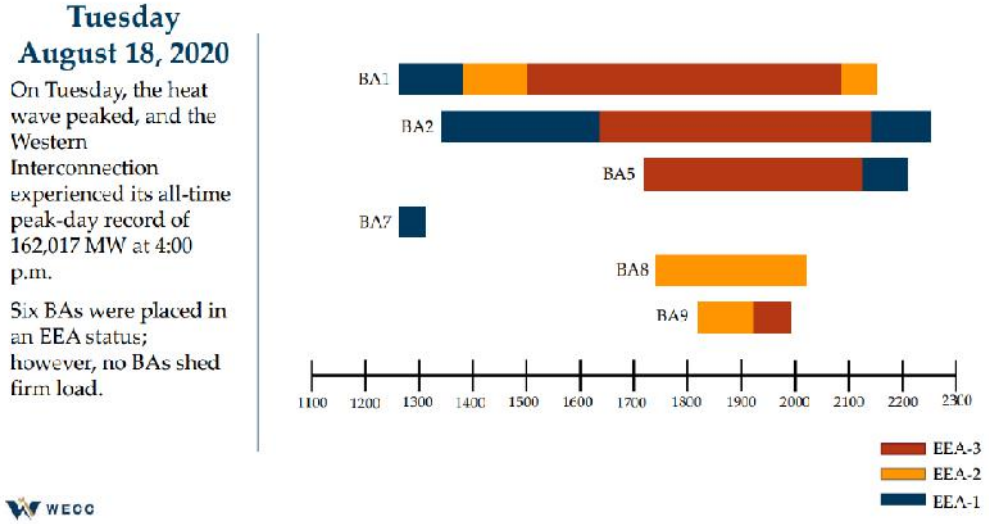
	June	July	August
2022			
2021			
2020			

PNM Talk to us. PNM.com

REGIONAL DYNAMICS IMPACT MARKET LIQUIDITY

Figure 19. PNM's hourly wholesale market purchases during the August 2020 heatwave





https://www.wecc.org/Administrative/Heatwave%20EEA%20Slides.pdf

- Tuesday August 18, 2020 was the peak of the heat wave and most challenging day for PNM operators and traders
- Purchases in hour 18 and 20 exhausted all PNM was able to buy in these hours of critical need despite offering high prices

- Five different Balancing Authorities were in EEA-2 or EEA-3 status on August 18, 2020.
- **PNM will continue to plan to be able to reliably serve customers under stressful system conditions such as these without an over reliance on the market.**

TAKEAWAYS

- Modeling and limits should focus on net peak periods since these are the most constrained hours
- Regional dynamics play a major role in market liquidity
- Planning should incorporate likelihood of regional constraints and weather events
- PNM has no plans to change its current modeled import limitations based on continued resource adequacy concerns in WECC and the need for conservatism in planning
- PNM is an active participant in the Energy Imbalance Market (EIM) – PNM must prove resource sufficiency in each interval in order to participate
- Market purchases and import limits refer to day-ahead and real-time purchases, and not long-term contracts for firm capacity

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by February 10, 2022.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: February 15, 2023

Topics: Existing system (regulatory and planning requirements), modeling framework

Start Time: 9:00 AM

Location: Virtual

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

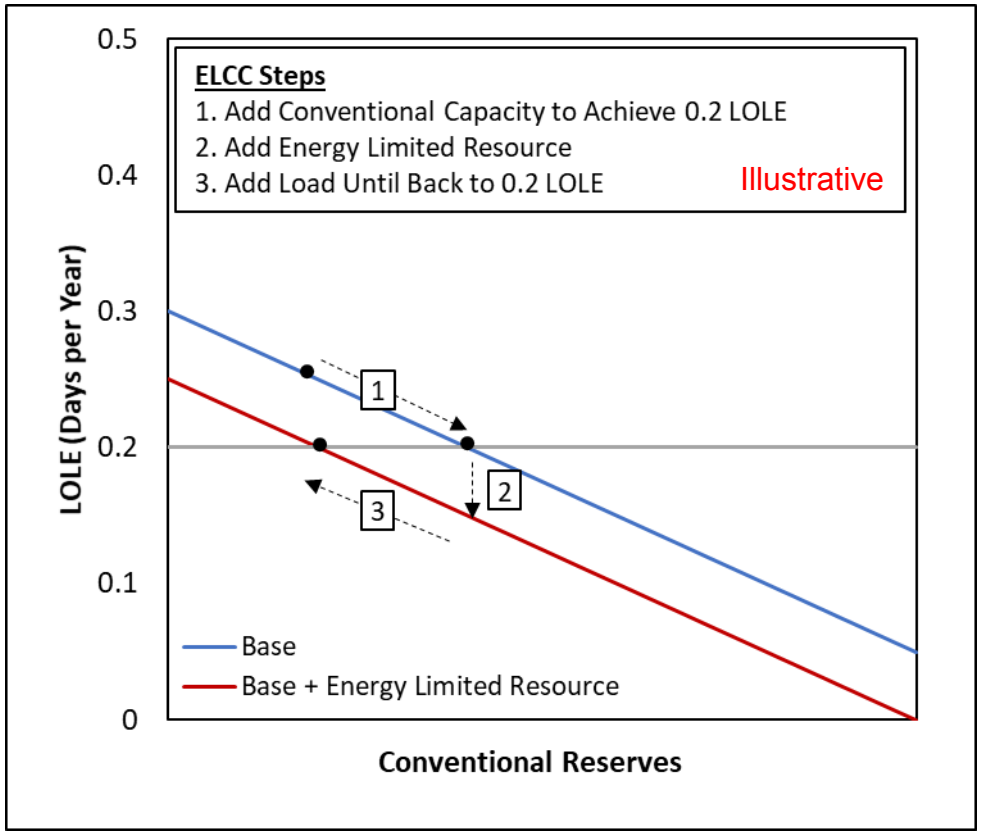
Thank you



APPENDIX

Effective Load Carrying Capability

Effective Load Carrying Capability (ELCC) describes the reliability contribution of an energy limited or non-dispatchable resource

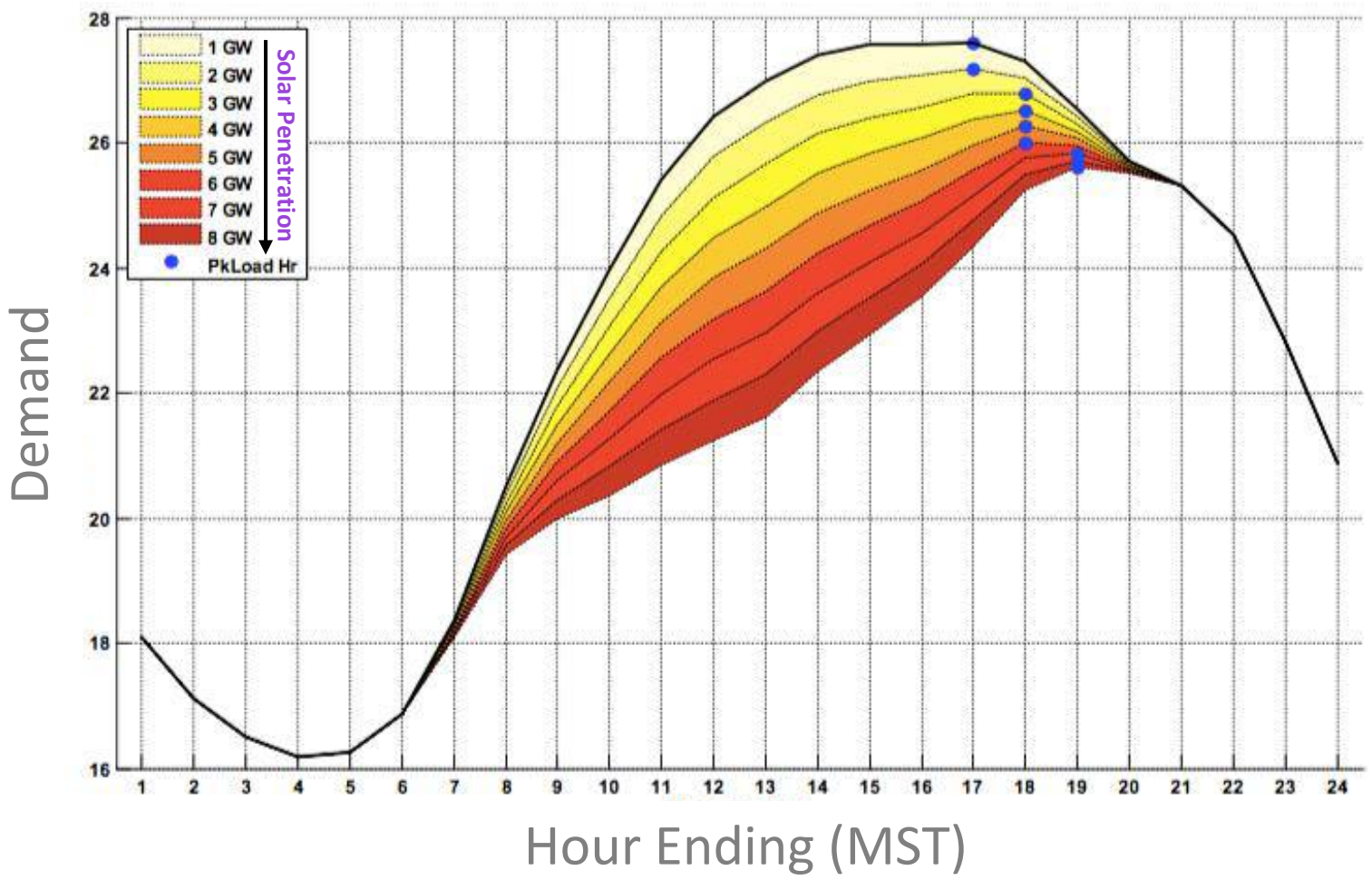


Effective Load Carrying Capability (ELCC) analysis adds load to offset the reliability contribution of the resource type under study. For example, an energy limited resource may be added to the system to improve reliability. This may be offset with load until the reliability target is achieved to quantify the reliability benefit.

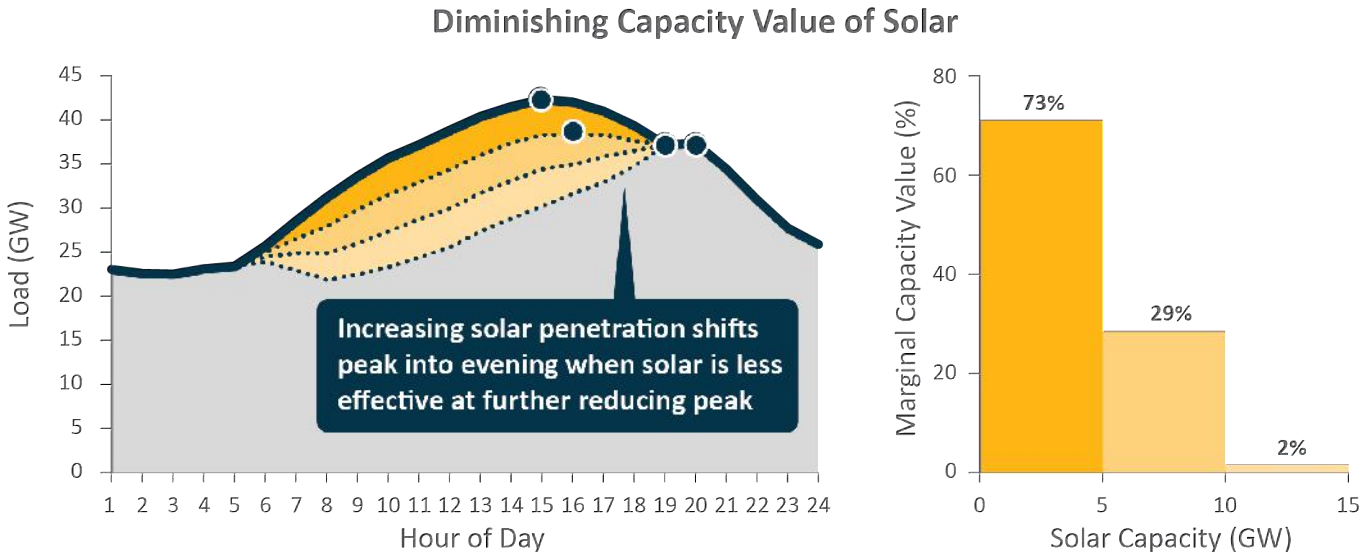
The same process may be performed on a non-dispatchable resource.

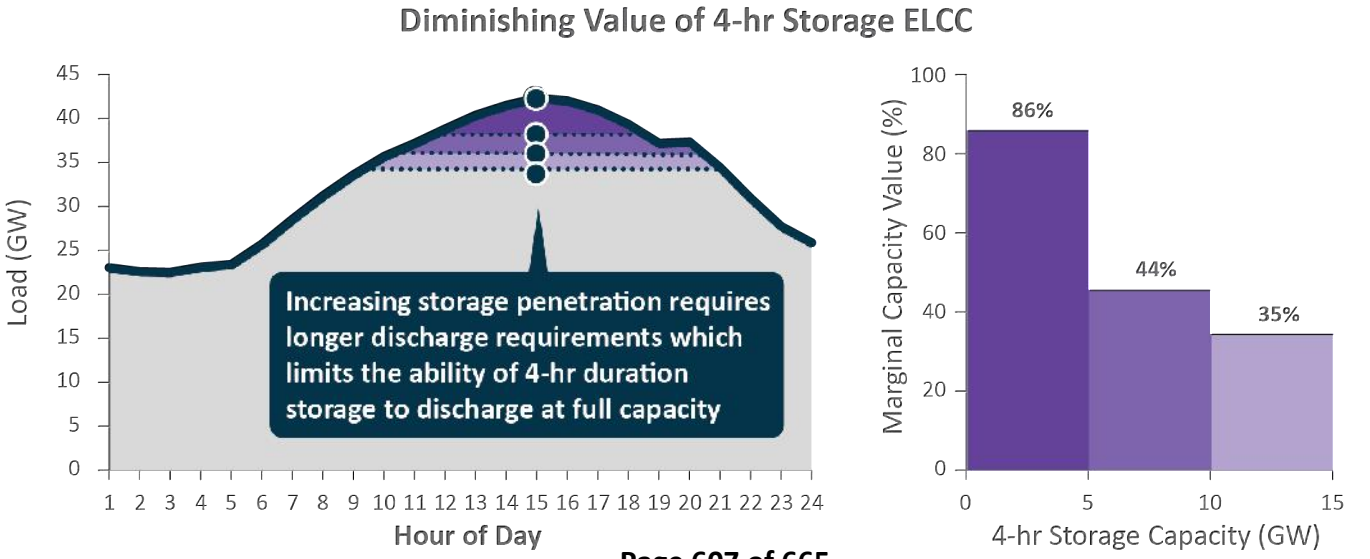
0.2 Loss of Load Expectation (LOLE) is utilized as the reliability target and equates to 2 days with generation shortage every 10 years.

Increased PV pushes net peak into evening (eventually after sunset)



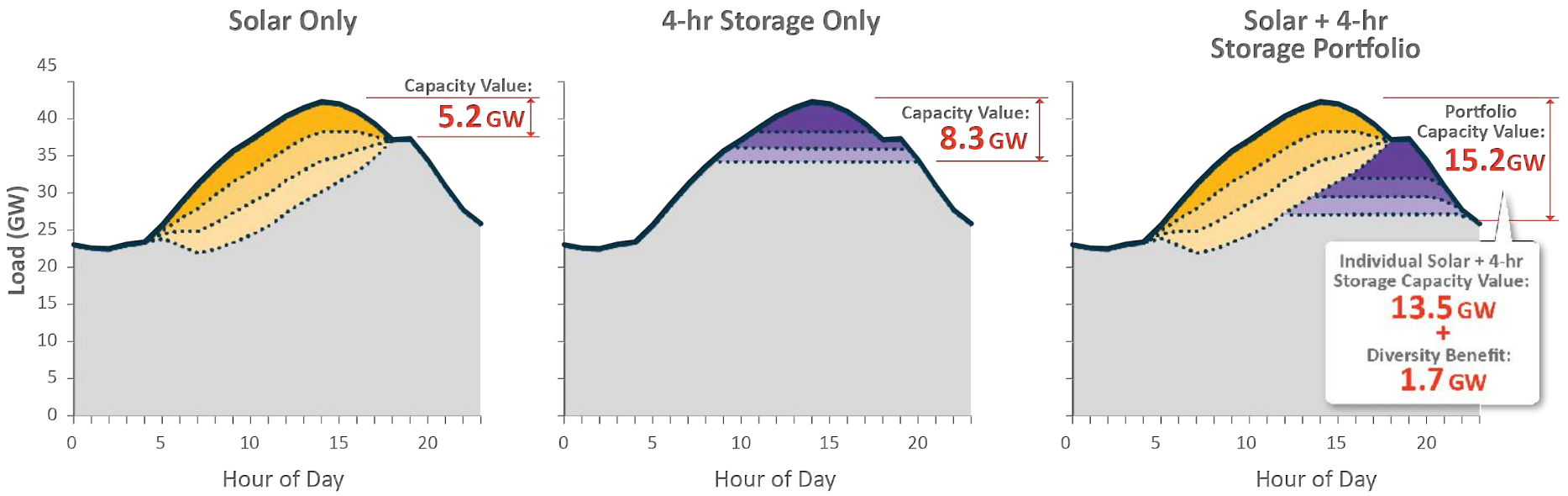
ELCC captures saturation effects with increasing resource penetration





ELCC Captures Synergistic Interactive Effects Between Resources

+ **Resources with complementary characteristics produce a combined ELCC that exceeds the sum of individual resources' ELCCs, producing a "synergistic interaction"**
  - This effect has been described as a "diversity benefit" between resources



PNM 2023-2042 IRP: Modeling Framework and Core Scenarios, RFI Selections, Existing System, and Economic Development

PUBLIC ADVISORY GROUP MEETING #14
STEERING MEETING #11

FEBRUARY 15, 2023



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01

- Questions and comments are welcome – one Person Speaks at a Time

02

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

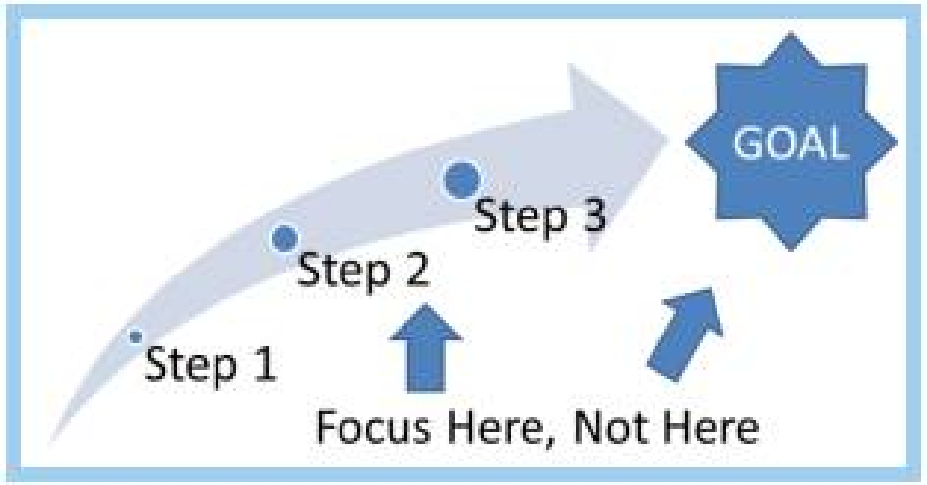
03

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulatory proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

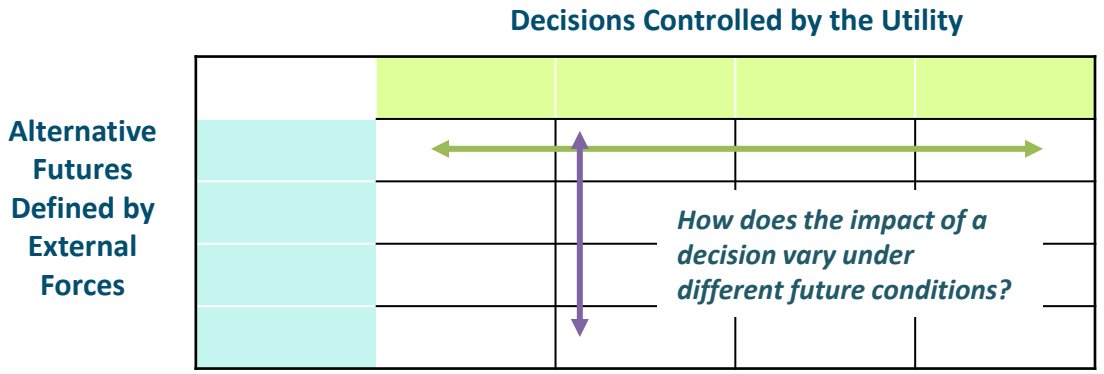
We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

- Modeling terminology
- IRP modeling framework and key elements in analysis timeline
- Scenario screening overview and examples
- Modeled technologies vs. RFP resources
- RFI selections for Phase 1 modeling
- Treatment of existing resources
- Economic Development forecast for IRP modeling
- IRP scenarios
- Time for questions or follow-ups from previous meetings

TERMINOLOGY

- A **scenario** describes potential key decisions made by PNM
- A **future** consists of a set of forecasts or conditions that describe a future state of the world; PNM generally has no ability to influence factors that determine which future becomes reality
- A **sensitivity** describes a change in a single element of a given future; sensitivity analysis is used to understand how sensitive the results are to the changed variable



MODELING FRAMEWORK

Utility decisions;

future portfolio choices made by the utility to meet objectives

e.g., carbon target, resources considered, plant retirements

Scenarios

Futures

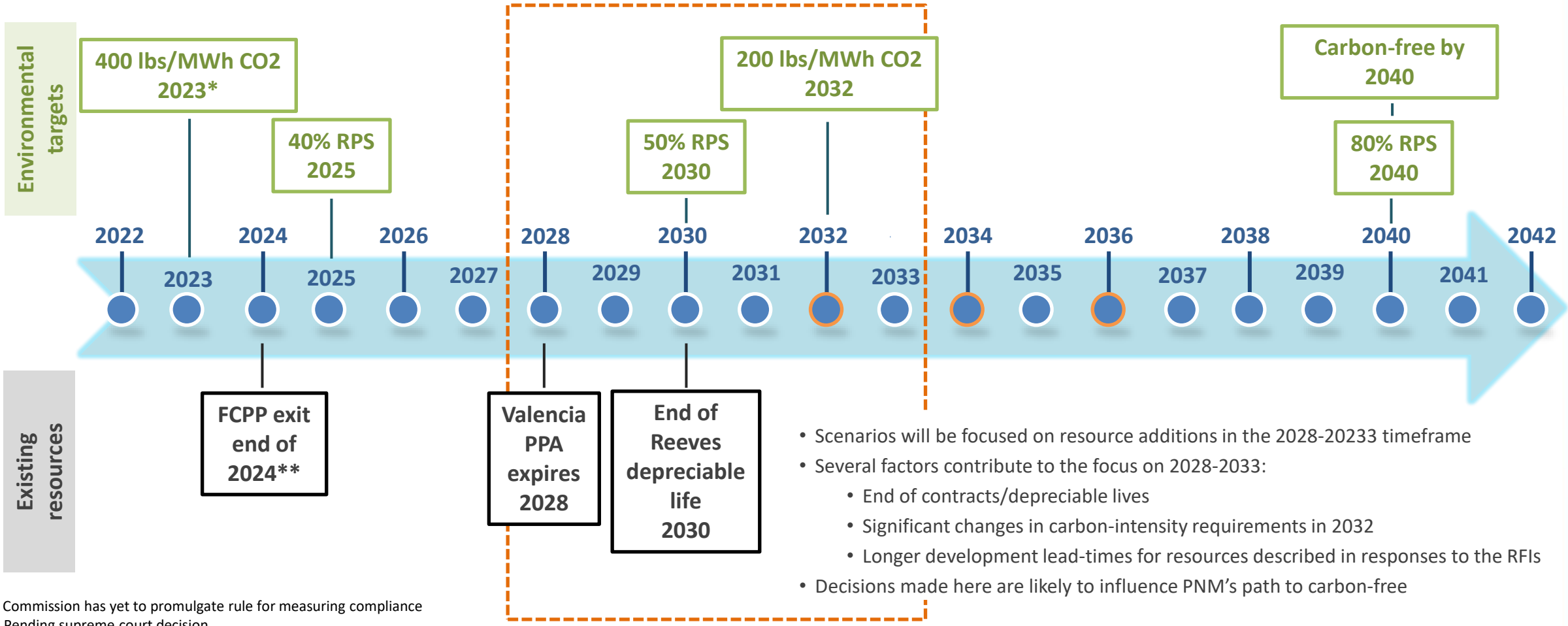
External forces; certain or uncertain variables outside of utility's control that present risks

e.g., gas price, load forecast, technology prices

Variation of selected parameter or variable within a scenario in order to understand its impact on key metrics

Sensitivities

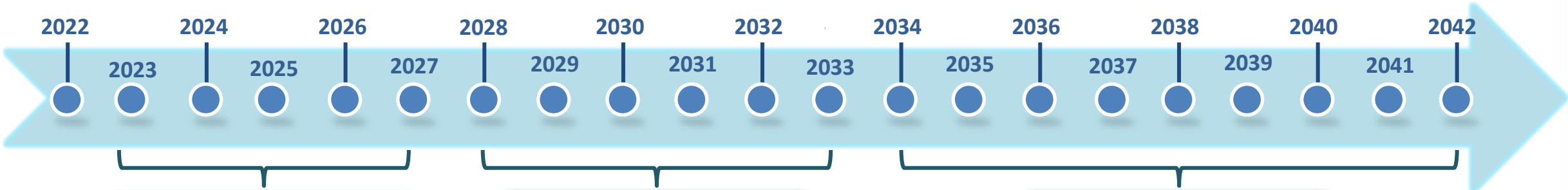
KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS



- Scenarios will be focused on resource additions in the 2028-20233 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs
- Decisions made here are likely to influence PNM's path to carbon-free

* Commission has yet to promulgate rule for measuring compliance
** Pending supreme court decision

POTENTIAL RESOURCE DECISIONS IN THE 2028-2033 TIMEFRAME IMPACT LONGER-TERM SYSTEM DYNAMICS



Near-term (Action Plan Period)
2023-2027:

Full transparency, low uncertainty

- The resource portfolio for this period has largely been determined through 2025; additional resources selected from near-term 2026-28 RFPs
- PNM may be required to act here to prepare for changes in the 2028-2033 period

Mid-term
2028-2033:

Focus of 2023 IRP analysis

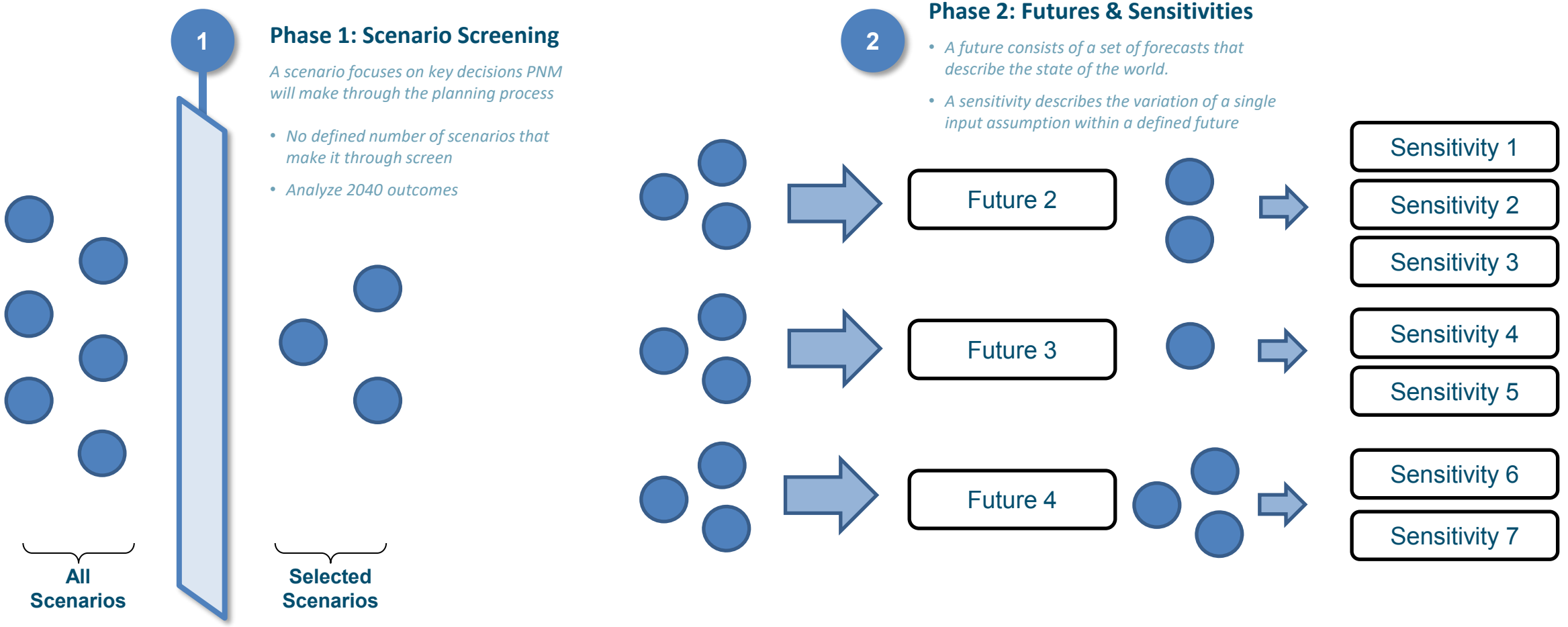
- IRP will evaluate best mix of known resource alternatives pivotal for enabling a carbon-free system by 2040
- Carbon intensity requirement of 200 lbs/MWh in 2032 is expected to be highly impactful
- Use of the scenario screening approach

Long-term
2034-2042:

Less transparency, high uncertainty

- Core scenarios outline additions in the 2028-2033 timeframe, which will impact PNM's portfolio in the later years of the study period

SCENARIO SCREENING ILLUSTRATIVE EXAMPLE: HIGH LEVEL



ILLUSTRATIVE MODELING PROCESS EXAMPLE #1

PHASE 1

Select core scenarios | ***Screen core scenarios*** | ***Select scenarios for further analysis***

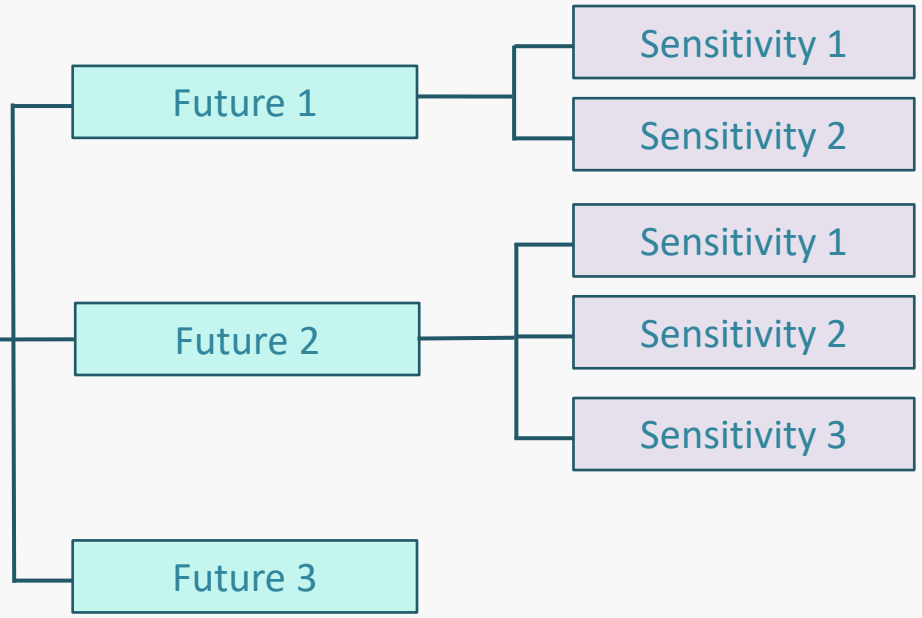
Scenario 1 → Screen → Scenario 1

Scenario moves to Phase 2

- *Identify potential resource options for key planning decisions in 2028-2033*
- *Core scenarios reflect the option to add from a set of resources with similar operating characteristics*

- *Screen core scenario against two capacity expansion cases:*
  1. *Current Trends & Policy future*
  2. *Current Trends & Policy w/ Strong Economic Development growth*
- *For each resulting portfolio, run 8760 production cost with both 50/50 and extreme weather load cases for both resulting portfolios*
- *If scenario needs no adjustments, it is ready for Phase 2*

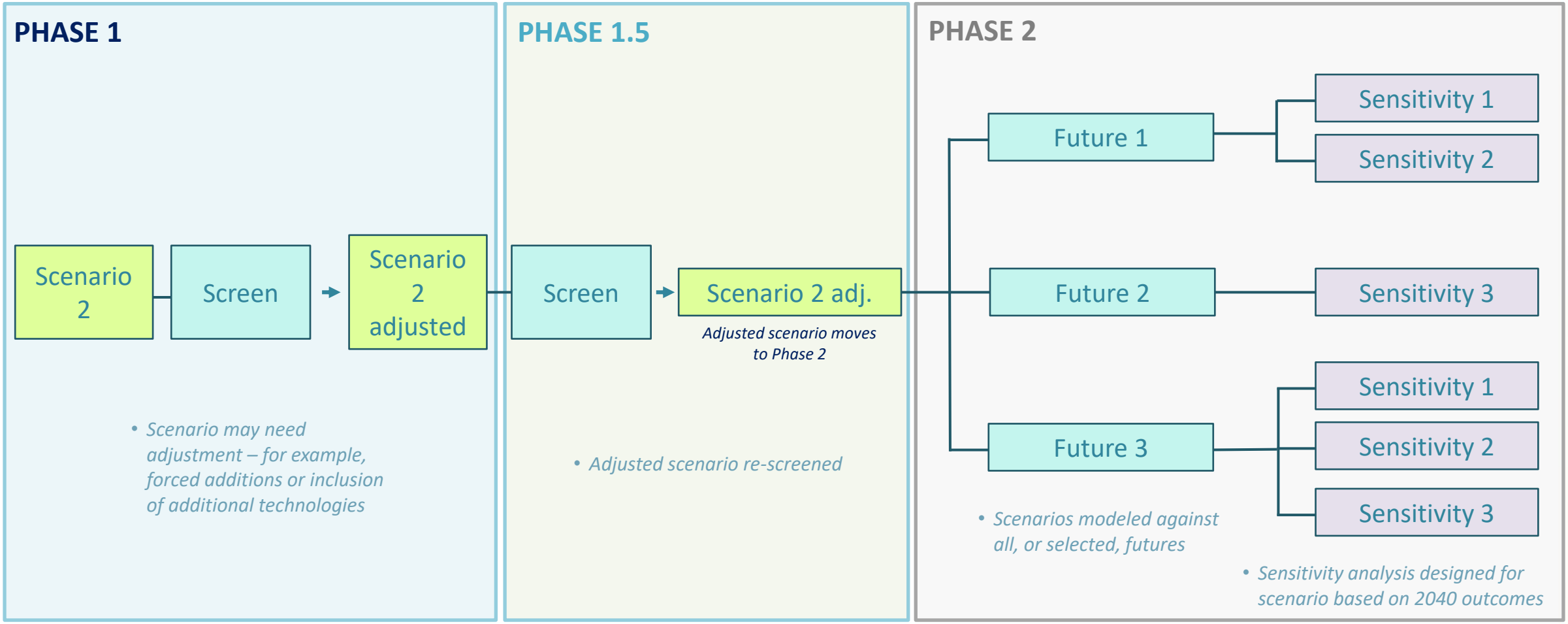
PHASE 2



- *Scenarios modeled against all, or a selection of, futures*
- *Sensitivity analysis designed for scenario based on 2040 outcomes*

- *Not all sensitivities will need to be evaluated under all futures – some combinations of scenario/ future/sensitivity may not make sense*

ILLUSTRATIVE MODELING PROCESS EXAMPLE #2



MODELED TECHNOLOGIES VS. RFP RESOURCES

The IRP is different from an RFP evaluation

- We do not intend to model every specific project, RFI response, model of equipment, etc.
- We are examining the type of operating characteristics and attributes of resources that will lead to the most-cost effective path to decarbonizing the system in a safe, reliable, and resilient way
- We will issue RFPs in the future to identify specific projects that can provide the types of operating characteristics and attributes that we identify in the IRP as leading to the most-cost effective portfolio
- For example – we do not need to model every turbine type or battery/storage chemistry, as many different types have similar characteristics

RFI SELECTIONS FOR PHASE 1 MODELING

- IRP analysis will focus on identifying the resource mix necessary to enable a carbon-free system by 2040
- When reviewing RFI responses and selecting technologies to model, we chose to focus on operating characteristics, not specific projects
- RFI technologies selected for Phase 1 modeling (in addition to other non-RFI technologies modeled):
    1. Long-duration storage:
        - Pumped Hydro Storage (70+ hours in duration, 85% efficiency)
            - Shorter duration variant may or may not need to be modeled depending on outcomes of other modeling
        - Iron-air storage (100 hours in duration, 38% efficiency)
    2. Natural gas:
        - Linear generator units
    3. Dispatchable generation with carbon capture:
        - NET power plant utilizing supercritical CO2 Allam Cycle
    4. Hydrogen:
        - Single site production, storage, and combustion
    5. Concentrated Solar Power with Thermal Energy Storage and/or other Thermal storage?
- Phase 2 modeling scenarios still in development, and depend heavily on Phase 1 results
- Phase 2 will also incorporate scenarios that study treatment of existing resources set for retirement within the planning period

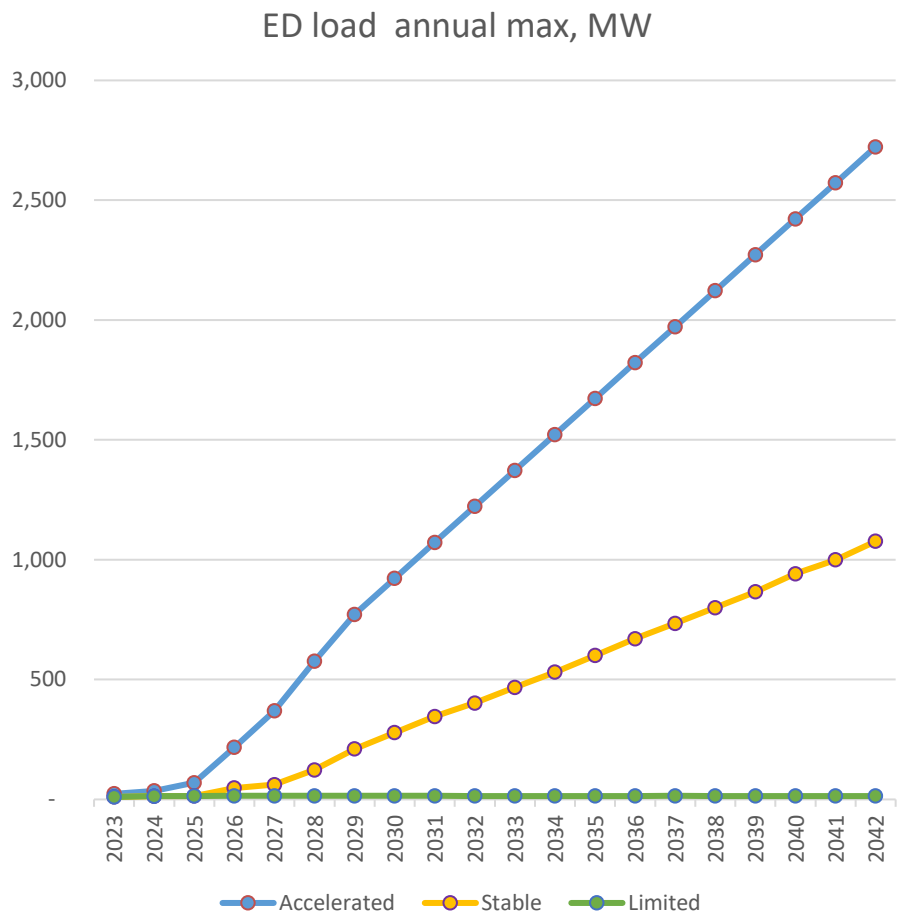
TREATMENT OF EXISTING SYSTEM RESOURCES

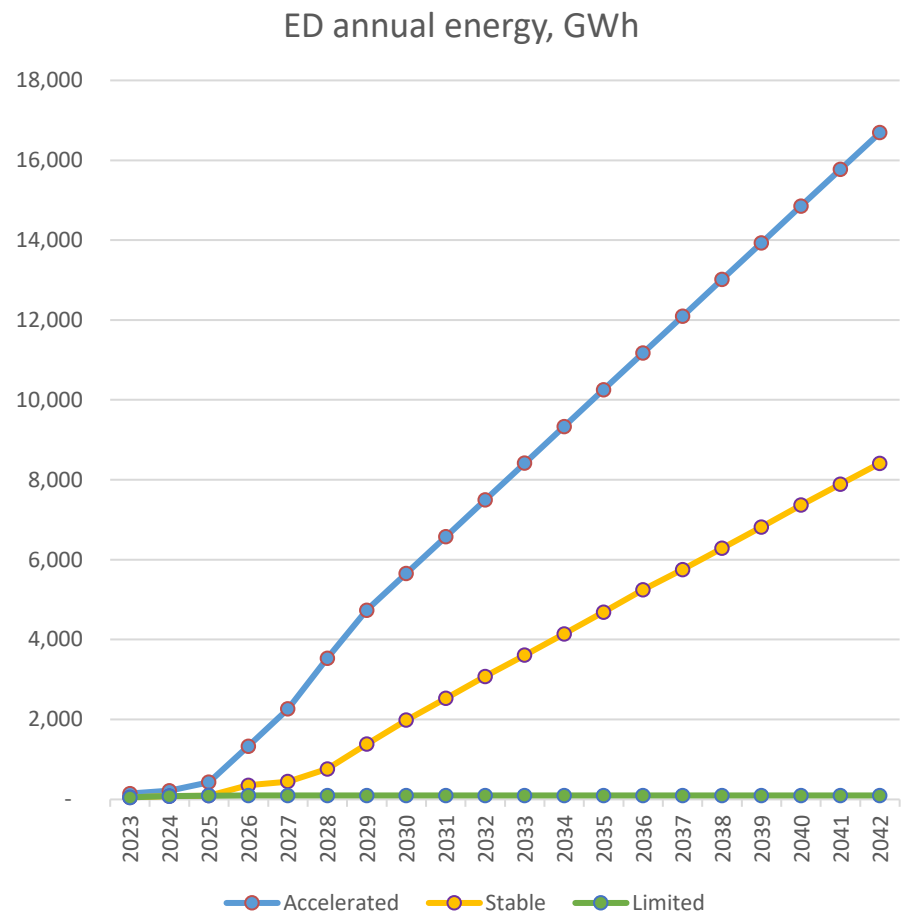
- The focus on existing system resources revolves around those that will retire during the planning period (2028-2033)
    - Reeves retires in 2030
    - Valencia PPA expires 2028
    - Four Corners exit in 2024*
- In Phase 1 modeling, these resources will be replaced with generic additions of wind/solar/storage, or additions of capacity specific to a given Core scenario
- In Phase 2 modeling, we will test scenarios against different futures and sensitivities to examine robustness of selected strategies

* Pending supreme court decision

ECONOMIC DEVELOPMENT FORECAST FOR IRP MODELING

- In Phase 1 modeling, core scenarios will be screened based on:
    a) Current trends & Policy Future
    b) Current Trends & Policy Future + Stable Economic Development forecast





PNM Talk to us. PNM.com

SCENARIOS FOR PHASE 1 MODELING

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



BASE TECHNOLOGIES SCENARIO

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



- Modeling allows for additions of generic resources in the base case and across all scenarios:
  - Solar (beginning in 2026)
  - Wind (beginning in 2033 – to compare against the Base + Wind Exp.)
  - Battery storage – 4-hr, with the option to convert to 8-hour (beginning in 2026)
- Once the RFP resources for 2026 are determined, those resources will become part of the base portfolio analyzed across all scenarios
- In other scenarios, additions of these resources are optimized around the addition of scenario resources

BASE + LONG-DURATION STORAGE SCENARIO

Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal long-duration storage project(s) from selection of technologies
- Allow addition of long duration storage projects beginning in 2028 (earliest COD tied to RFI)
- Allow model to optimize among additions of:
    - 85% efficiency storage resource with long-duration/mid-ramp (70-hr) (i.e., PHS)
        - Shorter duration variant
    - ~40% efficiency storage resource with mid-duration/long-ramp (100-hr) (Form)

BASE + NATURAL GAS SCENARIO

Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal natural gas project(s) from selection of technologies
- Allow addition of natural gas-fired projects beginning in 2026-2033 timeframe
- Allow model to optimize among additions of:
  - Generic gas project in any location
    - La Luz project (LM6000) – option to force addition if indicated by RFP analysis
    - Pinion project (LM6000) – option to force addition if indicated by RFP analysis
  - Linear generator units
- All gas resources will be converted to burn Hydrogen at the end of 2039 (assumes hydrogen economy)

BASE + WIND EXPANSION SCENARIO

Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal level of new transmission with access to generic wind resource in eastern New Mexico
- Transmission project added in 2030-2032 timeframe
- Transmission project reflects a new "pipe", with access to new "bubble" containing wind resources
- Allow for optimization regarding:
    - When to add the transmission line
    - The amount of new wind to add

BASE + CARBON CAPTURE SCENARIO

Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal carbon-free dispatchable project(s) from selection of technologies
- Allow for addition of carbon capture and storage technologies beginning in 2028
- Allow model to optimize among additions of:
    - Existing CCGT fitted with Carbon Capture and Storage (CCS) technology
    - New or existing CT with CCS
    - Net Power Plant with CO2 transport and storage

BASE + HYDROGEN SCENARIO

Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal hydrogen-fueled project(s) from selection of technologies
- A hydrogen facility will include electrolysis, on-site storage, and CT for combustion
- Hydrogen tax credits applied
- Allow for addition of hydrogen facilities starting in 2028
- Allow model to optimize among additions of:
    - Small project (250 MW)
        - Greenfield and brownfield options
    - Large project (500 MW)
        - Greenfield and brownfield options

2023 IRP FUTURES

Key assumption	Current Trends & Policy	High Economic Growth	Low Economic Growth	National Carbon Policy
Load forecast	Mid	High	Low	High
BTM PV forecast	Mid	High	Low	High
EV adoption forecast	Mid	High	Low	High
Building Electrification Forecast	Mid	Mid	Mid	High
Economic development	Limited	Accelerated	Limited	Stable
Gas price forecast	Mid	Mid	Low	High
Carbon price forecast	Mid	Mid	Mid	High
Technology cost forecast	Mid	Mid	Mid	Low

2023 IRP SENSITIVITIES

Sensitivity	Load forecast	Economic Development	BTM PV forecast	EV adoption forecast	Building electrification	Gas price forecast	CO2 price forecast	Technology costs	IRA tax credits & incentives
High load	High	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
Strong ED growth	Mid	Stable	Mid	Mid	Mid	Mid	Mid	Mid	Extended
Very strong ED growth	Mid	Accelerated	Mid	Mid	Mid	Mid	Mid	Mid	Extended
Extreme weather	P90 hot/cold	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
Low load	Low	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
TOU pricing	TOU load shaping	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
High BTM PV	Mid	Limited ED	High	Mid	Mid	Mid	Mid	Mid	Extended
Low BTM PV	Mid	Limited ED	Low	Mid	Mid	Mid	Mid	Mid	Extended
No BTM PV	Mid	Limited ED	Zero	Mid	Mid	Mid	Mid	Mid	Extended
High EV adoption	Mid	Limited ED	Mid	High	Mid	Mid	Mid	Mid	Extended
Low EV adoption	Mid	Limited ED	Mid	Low	Mid	Mid	Mid	Mid	Extended
High building electrification	Mid	Limited ED	Mid	Mid	High	Mid	Mid	Mid	Extended
High gas price	Mid	Limited ED	Mid	Mid	Mid	High	Mid	Mid	Extended
Low gas price	Mid	Limited ED	Mid	Mid	Mid	Low	Mid	Mid	Extended
IRP rule $40 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	$40/ton	Mid	Extended
IRP rule $20 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	$20/ton	Mid	Extended
IRP rule $8 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	$8/ton	Mid	Extended
PNM high CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	High	Mid	Extended
PNM mid CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
PNM low CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Low	Mid	Extended
Fast technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Low	Extended
Slow technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	High	Extended
IRA tax credits expire	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Expire 2032-2034
DERMS?	Mid	Limited ED	High	High	Mid	Mid	Mid	Mid	Extended

Questions or Follow-ups from Previous Meetings

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by March 10, 2022.

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: March 15, 2023

Topics: Scenario form, others TBD

Start Time: 9:00 AM

Location: Virtual

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



PNM 2023-2042 IRP: New IRP Rule, Gridworks Introduction, and Modeling Run Requests

PUBLIC ADVISORY GROUP MEETING #15
STEERING MEETING #12

MARCH 15, 2023



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – one Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

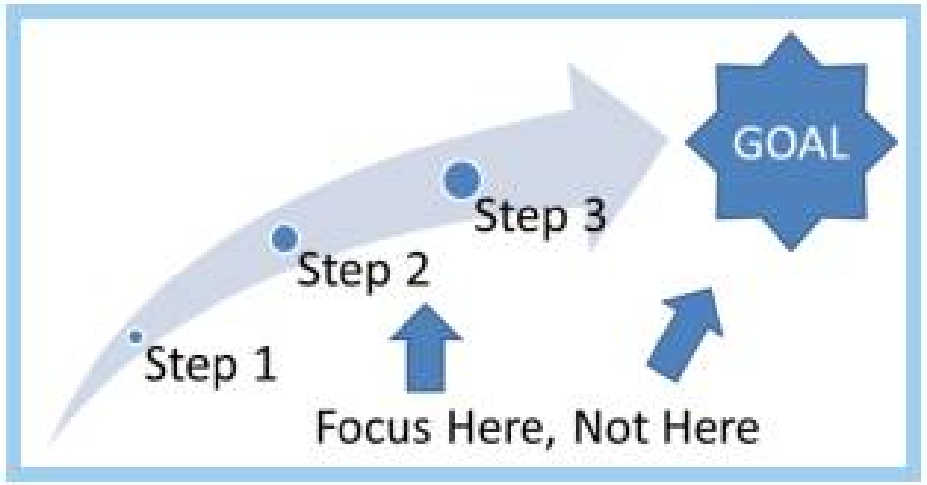
03 

- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulatory proceedings should be directed towards the specific filing.

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

- New IRP Rule
- Facilitated Stakeholder Process
- Discussion of Statement of Need and Action Plan
- Gridworks introduction
- Proposed Stakeholder engagement phases and tentative meeting schedule
- Invitation to participate and questions
- Discussion of modeling run requests

NEW IRP RULE AND THE PUBLIC PROCESS

- The PRC, through a rulemaking in Case No 21-000128-UT amended what is commonly referred to as the "IRP Rule" for Investor-Owned Utilities in the State of New Mexico (NMAC 17.7.3, which can be found here: https://www.srca.nm.gov/parts/title17/17.007.0003.html)
    - The new rule became effective on November 29, 2022, though there are appeals pending at the New Mexico Supreme Court
    - Under the new rule, PNMs IRP would have been due on September 1, 2023, rather than July 2023.
    - Section 17.7.3.9 describes a new Facilitated Stakeholder Process (FSP), which must start six months prior to filing the IRP
    - On February 17, 2023, PNM filed a motion seeking an extension on the IRP timeline
        - IRP filing date of December 15, 2023
        - Start the FSP on June 15, 2023
    - The PRC approved PNM's motion on March 1, 2023
- Over the next few months, we will transition from the Public Advisory Process begun under the old IRP rule to the new FSP
- We aim for the FSP to leverage all the Public Advisory work done so far, enhance outreach, and meet stakeholder expectations

FACILITATED STAKEHOLDER PROCESS (1 OF 2)

Key points related to the Facilitated Stakeholder Process outlined in 17.7.3.9

- The facilitator is appointed by the NMPRC – Gridworks has been selected
- The process commences 6 months prior to the filing of the IRP
- The goal is 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)
- The NMPRC does not participate in the process, aside from the selection and appointment of the facilitator (though the NMPRC utility division staff are allowed to participate)
- The facilitator shall notify the commission and utility of any perceived or actual conflicts that arise during the facilitated process
- The utility shall provide commission utility division staff and other stakeholders who have signed a confidentiality agreement reasonable access to the same modeling software used by the utility on equal footing as the utility, and the utility shall share all modeling information.
    - The utility shall perform a reasonable number of modeling runs per staff or a stakeholder, if requested by staff or a stakeholder, in accordance with commission precedent
- The facilitator, in consultation with the utility, is to issue notice of facilitated stakeholder meetings, and to host and moderate facilitated stakeholder meetings, including but not limited to, preparing the agenda, and acting as the coordinator between the utility's presentation and the stakeholders' questions and comments

FACILITATED STAKEHOLDER PROCESS (2 OF 2)

- Not later than six months after the facilitated stakeholder process commences, the utility shall file the IRP with the commission, explaining all resolved and unresolved issues resulting from the facilitated process
- Written public comments may be filed within 30 days of the utility's filing of the IRP
    - Written public comments may include the commenter's own draft Statement of Need and Action Plan for commission review
    - Written public comments shall be made part of the utility's IRP as addendums
- The utility shall file, within 60 days of the utility's filing of the IRP, a written response to all timely filed written public comments, stating whether it adopts any of the written comments as amendments to the IRP and the reasons why or why not
- The commission's utility division staff shall consider the filed written public comments and the utility's written responses and shall file a statement with the commission within 90 days of utility's filing of the IRP as to whether the statement of need and action plan comply with the policies and procedures of this rule
- If the commission has not acted within 120 days of the filing of the IRP, the statement of need and action plan are deemed accepted as compliant with the IRP rule; if the commission determines that the statement of need or action plan do not comply with the requirements of the IRP rule, the commission shall identify the deficiencies and return it to the utility with instructions for re-filing

STATEMENT OF NEED

Statement of Need 17.7.3.10

- 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.
- 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.

We want Stakeholders to start thinking about this now, as this is fundamental to the FSP

ACTION PLAN

Action Plan 17.7.3.11

- The utility's action plan shall:
    - Detail the specific actions the utility shall take to implement the IRP spanning a three-year period following the filing of the utility's IRP
    - Detail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission
    - Include a status report of the specific actions contained in the previous action plan
- The utility shall update the commission by filing two reports describing the utility's implementation of the action plan. These reports shall be filed in the existing IRP docket one year after the filing of the IRP, and two years after the filing of the IRP, respectively
- An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations
- The utility shall promptly notify the commission and participants of material events that would have the effect of changing the results of the utility's action plan had those events been recognized when the action plan was developed
- In accepting the action plan, the commission shall take into consideration contractual obligations as between the utility and any regional transmission organizations or balancing authorities of which the utility is a member

The decarbonization of our economy is within reach, and more important than ever.

We convene, educate, and empower stakeholders working to decarbonize our economy.



GRIDWORKS

www.gridworks.org
GRIDWORKS is a non-profit organization.

GRIDWORKS' Team Members for New Mexico IRP Activities



Deborah Shields
Project Administrator



Amanda Ormond
Facilitator



Margie Tatro
Facilitator



Matthew Tisdale
Executive Director, Gridworks

Stakeholder Engagement Envisioned to Include Three Phases

March – May	June – August	Sept – Nov → IRP Dec. 15
March 28: 9-10:30 AM May 4: 9 – 3 workshop May 18, Tentative	June 1 and 15, Tentative June 29, possible workshop, Tentative July 13 and August 17, Tentative	Sept. 14, Tentative Oct 19, Tentative Dec. 19, Tentative
1: Grounding and Statement of Need	2: Model Runs and Produce Action Plans	3: IRP Reviews
Grounding Includes: System Requirements, Resource Options, and possibly Load Scenarios. Stakeholder engagement is intense and focuses on the big picture. Builds on 12 prior months of PNM's Public Advisory Process.	Stakeholder Modeling Subgroup runs own models or reviews and engages with utility modelers. Action Plans are developed. Engagement is intense for those with modeling interest/expertise.	Reviews monthly by all interested stakeholders for feedback, areas where utility needs input, etc. Stakeholder Engagement is less intense than previous two phases.

You are Invited to Participate as Stakeholders

- Stakeholders are expected to:
  - **Provide actionable feedback regarding Statement of Need, Action Plan, and IRP Drafts.**
  - Attend as many meetings as possible. Review meeting materials in advance. Review summaries from meetings, especially if a meeting is missed.
  - Work offline in subgroups, if interested.
  - Serve as respectful, active participants during discussions.
  - Consider views and input of other stakeholders.
  - Share experience and expertise, perhaps presenting to the group, as needed.
- Please let us know if there are stakeholders that you feel need to be represented in this process. The Gridworks team will invite any missing voices to participate.
- We look forward to our first Facilitated Stakeholder Engagement Meeting, **March 28, 9:00 – 10:30 AM**.

You will have the opportunity to state is important to you in this process, volunteer to work in subgroups on specific topics, provide feedback, and ask questions.

Questions?

Also, please feel free to contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

PUBLIC ADVISORY PROCESS GOING FORWARD

- Going forward, we will begin the transition to the Gridworks facilitated process
- The PNM Public Advisory meetings scheduled for April and May will be replaced with meetings facilitated by Gridworks
- All further communications from PNM and Gridworks will be coordinated
- Our first meeting of the new process will be on March 28, 2023 – we hope you will attend

MODELING RUN REQUESTS

MODELING RUN REQUESTS

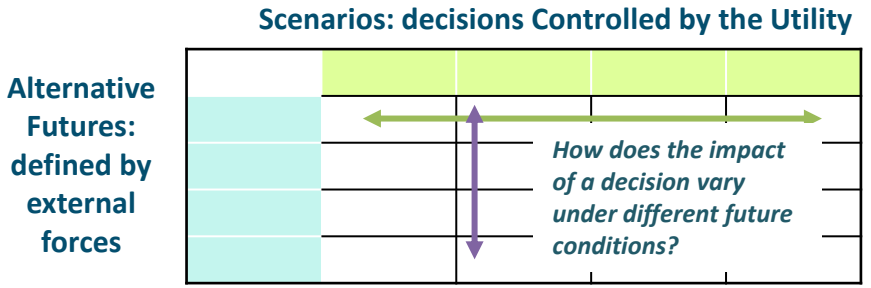
- We anticipate a modeling request sub-group that will work to develop modeling run requests within the Facilitated Process
- One of the deliverables from the modeling request sub-group will be identification of a consensus set of modeling runs for PNM to implement on behalf of all stakeholders
    - If a requested modeling run is not possible, PNM will provide a discussion of why such a run is not possible, and suggest a potential alternative to the requested run
- PNM will provide a list of modeling runs PNM intends to complete in the IRP analysis

Process for requesting a modeling run (not already conducted by PNM):

1. Create technological scenarios by grouping technologies to evaluate
2. Choose future
3. Choose one or more sensitivities to augment base future assumptions (optional)
    - If more than one sensitivity is selected, an examination must be conducted to make sure the sensitivities implied in the chosen future do not conflict with additional sensitivities

TERMINOLOGY AND MODELING FRAMEWORK

- A **scenario** describes potential key decisions made by PNM
- A **future** consists of a set of forecasts or conditions that describe a future state of the world; PNM generally has no ability to influence factors that determine which future becomes reality
- A **sensitivity** describes a change in a single element of a given future; sensitivity analysis is used to understand how sensitive the results are to the changed variable



Utility decisions;
future portfolio choices made by the utility to meet objectives
e.g., resources considered, plant retirements

Scenarios

Futures

External forces; certain or uncertain variables outside of utility's control that present risks
e.g., gas price, load forecast, technology prices

Variation of selected parameter or variable within a scenario in order to understand its impact on key metrics

Sensitivities

PNM SCENARIOS FOR PHASE 1 MODELING

Base technologies only



PNM relies on solar, wind, and storage (li-ion) to meet future need and carbon emission reduction goals

Modeling allows for additions of generic resources in the base case and across all scenarios:

- Solar (beginning in 2026)
- Wind (beginning in 2033 – to compare against the Base + Wind Exp.)
- Battery storage – 4-hr, with the option to convert to 8-hour (beginning in 2026)
- In other scenarios, additions of these resources are optimized around the addition of scenario resources

Base + long-duration Storage



PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe

Allow model to optimize additions of long duration storage projects beginning in 2028 (earliest COD tied to RFI):

- 85% efficiency storage resource with long-duration/mid-ramp (70-hr) (i.e., PHS)
- Shorter duration variant
- ~40% efficiency storage resource with mid-duration/long-ramp (100-hr) (Form)

Base + natural gas



PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040

Allow model to optimize additions of natural gas-fired projects beginning in 2026-2033:

- Generic gas project in any location
  - La Luz project (LM6000) /Pinion project (LM6000) – option to force addition if indicated by RFP analysis
- Linear generator units
- H2 conversion assumes H2 economy

Base + wind expansion



PNM seeks strategic transmission expansion in the late 2020's/early 2030s

Transmission project added in 2030-2032 timeframe:

- New transmission project reflects a new "pipe", with access to new "bubble" containing wind resources
- Allow for optimization regarding:
  - When to add the transmission line
  - The amount of new wind to add

Base + carbon capture



PNM relies on carbon capture and sequestration technologies to meet future capacity need

Allow model to optimize additions of carbon capture and storage technologies beginning in 2028:

- Existing CCGT fitted with Carbon Capture and Storage (CCS) technology
- New or existing CT with CCS
- Net Power Plant with CO2 transport and storage

Base + H2/early gas conversion



PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs

- A hydrogen facility will include electrolysis, on-site storage, and CT for combustion
- Hydrogen tax credits applied
- Allow model to optimize additions of hydrogen facilities starting in 2028:
  - Small project (250 MW), greenfield and brownfield options
  - Large project (500 MW), greenfield and brownfield options

2023 IRP CORE FUTURES

Key assumption	Current Trends & Policy	High Economic Growth	Low Economic Growth	National Carbon Policy (Carbon-free by 2035)
Load forecast	Mid	High	Low	High
BTM PV forecast	Mid	High	Low	High
EV adoption forecast	Mid	High	Low	High
Building Electrification Forecast	Mid	Mid	Mid	High
Economic development	Limited	Accelerated	Limited	Stable
Gas price forecast	Mid	Mid	Low	High
Carbon price forecast	Mid	Mid	Mid	High
Technology cost forecast	Mid	Mid	Mid	Low

2023 IRP SENSITIVITIES

	Sensitivity	Load forecast	Economic Development	BTM PV forecast	EV adoption forecast	Building electrification	Gas price forecast	CO2 price forecast	Technology costs	IRA tax credits & incentives
Load	High load	High	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Strong ED growth	Mid	Stable	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Very strong ED growth	Mid	Accelerated	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Extreme weather	P90 hot/cold	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Low load	Low	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	TOU pricing	TOU shaping	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
BTM	High BTM PV	Mid	Limited ED	High	Mid	Mid	Mid	Mid	Mid	Extended
	Low BTM PV	Mid	Limited ED	Low	Mid	Mid	Mid	Mid	Mid	Extended
	No BTM PV	Mid	Limited ED	Zero	Mid	Mid	Mid	Mid	Mid	Extended
	High EV adoption	Mid	Limited ED	Mid	High	Mid	Mid	Mid	Mid	Extended
	Low EV adoption	Mid	Limited ED	Mid	Low	Mid	Mid	Mid	Mid	Extended
	High building electrification	Mid	Limited ED	Mid	Mid	High	Mid	Mid	Mid	Extended
	DERMS	Mid	Limited ED	High	High	Mid	Mid	Mid	Mid	Extended
Gas price	High gas price	Mid	Limited ED	Mid	Mid	Mid	High	Mid	Mid	Extended
	Low gas price	Mid	Limited ED	Mid	Mid	Mid	Low	Mid	Mid	Extended
Carbon price	IRP rule $40 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	$40/ton	Mid	Extended
	IRP rule $20 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	$20/ton	Mid	Extended
	IRP rule $8 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	$8/ton	Mid	Extended
	PNM high CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	High	Mid	Extended
	PNM mid CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	PNM low CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Low	Mid	Extended
Technology costs	Fast technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Low	Extended
	Slow technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	High	Extended
	IRA tax credits expire	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Expire 2032-2034

TECHNOLOGIES BY SCENARIO

As defined:

Base technologies only



- Solar
- Wind (beginning in 2033)
- Battery storage (4-hr)
- *Additions of these technologies optimized in all scenarios*

Base + long-duration Storage



- Long-duration Pumped-hydro storage (70-hr)
- Shorter duration Pumped-hydro storage (8 to 12-hr)
- Long-duration iron-air storage (100-hr)

Base + natural gas



- Generic gas project (Combustion turbine)
- Linear generator units
- *All resources converted to burn Hydrogen in 2040*

Base + wind expansion



- New transmission project reflects a new “pipe”, with access to new “bubble” containing wind resources

Base + carbon capture



- Existing CCGT fitted with Carbon Capture and Storage (CCS) technology
- New or existing CT with CCS
- Net Power Plant with CO2 transport and storage

Base + H2/early gas conversion



- Hydrogen facility with on-site electrolysis, storage, and CT for combustion
  - Small project (250 MW), greenfield and brownfield options
  - Large project (500 MW), greenfield and brownfield options

Other technology options:

- Concentrated solar power with thermal energy storage
- Thermal energy storage (steam turbine)
- Flow battery (10-hr)
- Compressed Air storage
- Liquid air storage

- Option to add other resources to bubble in addition to/in place of wind

MODELING RUN CREATION BY STEP

Step 1: define scenario – choose technologies

- Base technologies
- Long duration storage
- Natural gas
- Transmission expansion
- Carbon capture & storage
- Early adoption H2

Step 2: Choose future under which to evaluate scenario

- Current Trends & Policy
- High Economic Growth
- Low Economic Growth
- National carbon policy

Step 3: Choose one or more sensitivities to augment base future assumptions (optional)

Load
- **High load**
- Strong ED growth
- Very strong ED growth
- Extreme weather
- Low load
- TOU pricing

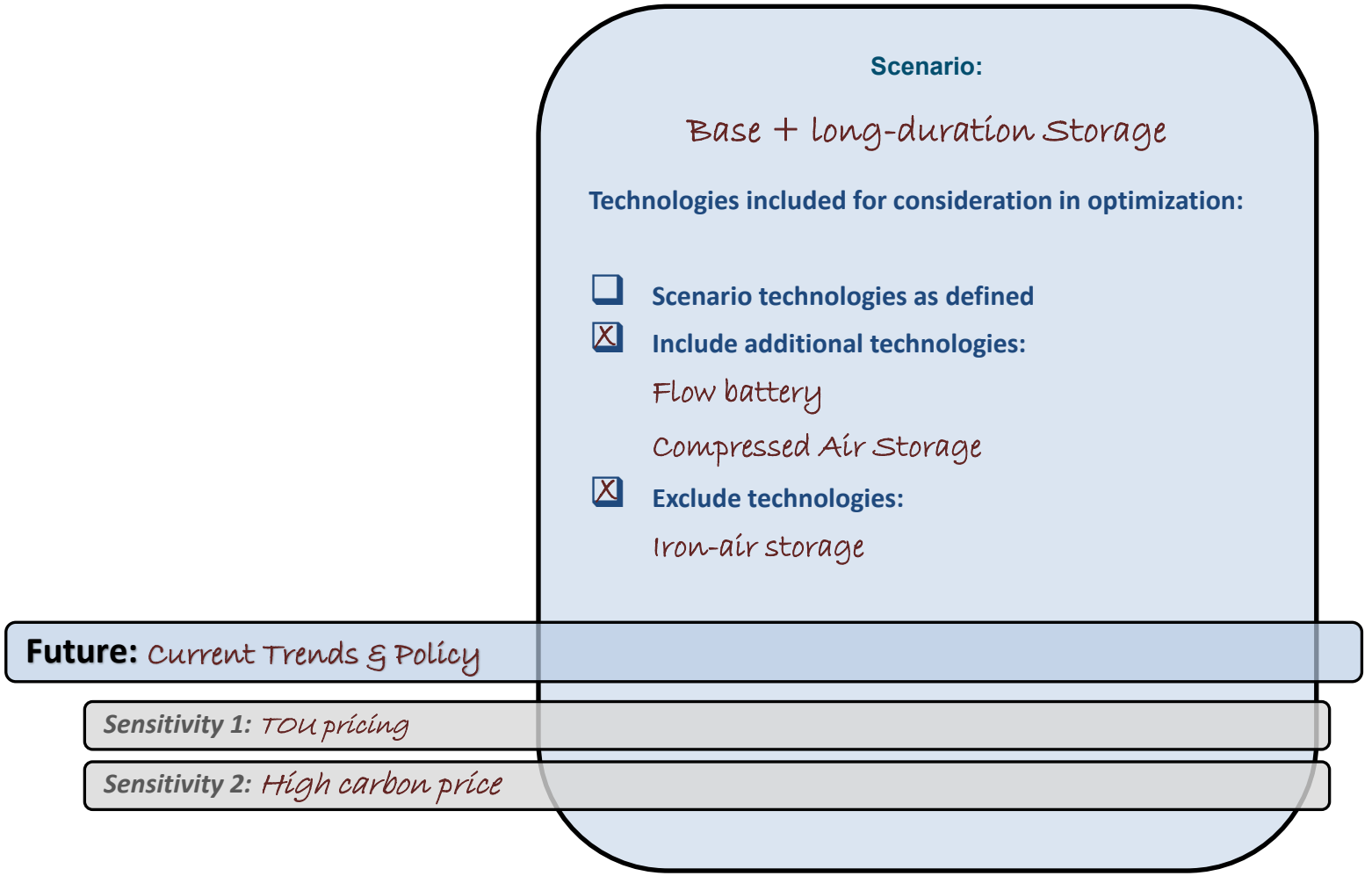
Technology costs
- Fast technology advancement
- Slow technology advancement
- IRA tax credits expire

Gas price
- High gas price
- Low gas price

Behind-the-meter
- High BTM PV
- Low BTM PV
- No BTM PV
- High EV adoption
- Low EV adoption
- High building electrification
- DERMS

Carbon price
- IRP rule $40 CO2 price
- IRP rule $20 CO2 price
- IRP rule $8 CO2 price
- PNM high CO2 price
- PNM mid CO2 price
- PNM low CO2 price

MODELING RUN EXAMPLE



NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: March 28, 2023

Topics: Stakeholder Engagement kick-off

Start Time: 9:00 AM

Location: Virtual

Thank you



Table of Contents

March 28, 2023 Meeting #1: Orientation for PNM Integrated Resource Plan 1

Agenda 1

Stakeholder Orientation Slide Deck 4

May 4, 2023 Meeting #2: PNM Integrated Resource Plan Stakeholder Workshop 14

Agenda 14

Stakeholder Workshop Slide Deck 15

Statement of Need Requirements Slide Deck 33

IRP Candidate Resources Slide Deck 45

Modeling Framework Timeline Slide Deck 74

Modeling Inputs Slide Deck 110

Acronym List 117

Candidate Resources 138

Modeling Phases 143

Climate Action 146

Probabilistic Modeling of Climate Change Impacts on Renewable Energy and Storage Requirements for NM's Energy Transition Act 148

Mitchell Foundational Issues 196

Amended IRP Rule (Redlined) 199

Stakeholder Questions 214

Interwest Letter 217

Analytical Review of PNM's IRP 218

Interwest IRP Comments 248

Steering Meeting Slide Deck 256

May 18, 2023 Meeting #3 274
Agenda 274
Meeting Slide Deck 275
Confidentiality Agreement 285
Modeling Topics 291
Proposed Structure for Modeling 303
Statement of Need Outline 312
June 1, 2023 Meeting #4 315
Meeting Slide Deck 315
Update from Modeling Core Group Slide Deck 326
Statement of Need Outline 332
Probabilistic Modeling Of Climate Change Impacts On Renewable Energy And Storage Requirements For Nm's Energy Transition Act 337
June 15, 2023 Meeting #5 351
Meeting Slide 351
Initial Modeling Results Slide Deck 362
Statement of Need Outline 377
June 29, 2023 Meeting #6 383
Agenda 383
Meeting Deck Slides 384
Modeling Results Update Slide Deck 401
Modeling Best Practices for a Decarbonized Future 444
Statement of Need 463
Statement of Need Parking Lot 468
Statement of Need Stakeholder Input 472

July 27, 2023 Meeting #7 474
Agenda 474
Meeting Slide Deck 475
Modeling Results Update Slide Deck 487
Modeling Q&A 520
Statement of Need Update 532
August 31, 2023 Meeting #8 537
Meeting Slide Deck 537
Modeling Results Update Slide Deck 558
Statement of Need Update 620
September 28, 2023 Meeting #9 626
Meeting Slide Deck 626
Modeling Results Update Slide Deck 648
Stakeholder Engagement Comment Session Slide Deck 685
Proposed Framework for Action Plan Items 690
Statement of Need Skeleton 692
Statement of Need 694
October 19, 2023 Meeting #10 700
Meeting Slide Deck 700
Modeling Results Update Slide Deck 711
Statement of Need Draft 737
Action Plan Draft 741
Action Plan Mapping 744

GRIDWORKS

Gridworks would like to invite you and your organization to engage with us in shaping Public Service Company of New Mexico's 20-year Integrated Resource Plan

WHEN: Tuesday, March 28, 2023

TIME: 9:00 - 10:30 AM Mountain Daylight Time

WHERE: Webex. Please go to https://www.pnmforwardtogether.com/schedule-and-events. You will see this March 28 meeting listed; please click on "REGISTER" to be added to the meeting.

The purpose of the meeting is to hear from and enlist the help of people who have a stake in the Public Service Company of New Mexico's 20-year plan. This plan, known as the Integrated Resource Plan (or IRP), covers the 2023-2043 timeframe.

MARCH 28 MEETING TOPICS

- Introductions of stakeholders and facilitation team.
- Describe how stakeholders can participate and how much time may be required.
- Answer questions you might have.
- Discuss meeting schedule and expectations of stakeholders.
- Discuss initial working groups and volunteers to participate.
- Identify critical missing voices or organizations we should invite.
- Discuss next steps in preparation for May 4 (in person) workshop.

BACKGROUND

In November of 2022, the New Mexico Public Regulation Commission (PRC) put new procedures in place for the state's investor-owned electric utilities to follow to engage stakeholders in developing their 20-year Integrated Resource Plans (IRP). PNM will be filing their plan on Dec. 15, 2023. The PRC appointed Gridworks (www.gridworks.org) as the independent facilitator to lead a stakeholder process intended to advise the utility and reach potential agreement on two key elements of the IRP – the statement of need and action plan.

WHY WE WOULD LIKE YOU TO CONSIDER PARTICIPATING

A few questions might help to explain why we would like you to consider participating in this process:

1) Why is my voice important to this planning process?

   PNM will purchase energy to serve you, your business or community and you will pay for the energy they choose. You may be a customer or provider (current or future) to PNM, you may be responsible for land on which PNM has facilities, or you may care about how the largest electric utility in New Mexico is planning to meet the electricity needs of over 540,000 customers over the next 20 years. You might be interested in how the New Mexico Energy Transition Act and other recent laws are changing the landscape in which our electricity is produced and delivered. Finally, you may feel strongly about how electricity decisions made today may affect future generations or potential economic development within New Mexico.

2) What makes this process different from past Public Advisory efforts regarding IRPs?

GRIDWORKS

In the past, utilities have conducted public advisory activities to inform stakeholders about the development of the IRP. Now, an independent facilitator was appointed by the New Mexico Public Regulation Commission to bring stakeholders together to provide input on the plan, to help expand and make it easier for stakeholders' opinions to be included. Gridworks is interested in your views and wants you to have opportunities to hear the views of other stakeholders.

3) Why is it critical to be involved at this time?

The electrical grid is undergoing a significant transformation. The transition away from fossil fuels and continued need for system reliability combined with the goal of minimizing costs for customers makes the current decisions regarding this transition critical to all New Mexicans. The voice of all New Mexicans is important as we look to balance the direction and the speed of this transition.

4) Have actions regarding new electricity resources for the next 3 years already been put in place, and if so, how will my input make a difference?

While PNM has performed planning on the general structure of the transition, many implementation details have not been settled. The planning done during the IRP update focuses not only on near-term resource additions, but also addresses near-term actions needed to position the system to meet environmental and regulatory requirements in a reliable and affordable way over the long term. While some actions in the near-term have already been put in place, this planning effort will examine whether additional actions must be taken to ensure the next phase of the system's transition (2028-2033) will meet stakeholders' expectations. It is critical for interested stakeholders to participate in this process and make their voices heard.

5) What would be expected of me if I decide to participate?

The most important contribution you can make to this effort is to provide feedback and opinions regarding PNM's 2023 Integrated Resource Plan.

You will be asked to attend as many meetings as possible. The current plan includes nine 90-minute meetings via a virtual platform and two in-person workshops between March and December 2023. A schedule of meetings is shown on page 3. The following is a list of roles and responsibilities for stakeholders who choose to participate:

- Review meeting materials in advance.
- Work offline in small subgroups, if interested.
- Serve as respectful, active participants during discussions.
- Consider views and input of other stakeholders.
- Share experiences and expertise.
- Attend as many meetings as possible.
- Review the notes and materials from any missed meetings.

6) Who should I contact for more information? info@gridworks.org or Margie Tatro, mtatro@gridworks.org, 505-205-0838.



SCHEDULE OF STAKEHOLDER MEETINGS

Below is the schedule as it currently exists. Meeting dates are not expected to change, but adjustments to exact times and meeting agenda topics are possible.

DATE	TIME (Mountain Daylight Time)	VENUE	PURPOSE
Mar. 28, 2023	9:00 – 10:30 AM	Webex	Orientation meeting and hearing from stakeholders about how they would like to engage going forward.
May 4, 2023	9:00 AM – 3:00 PM Lunch provided	In-person workshop, Albuquerque	Build a shared foundation of knowledge, provide opportunities for informal discussions among stakeholders, and begin work of subgroups.
May 18, 2023	Proposed 9:00 – 10:30 AM	Webex	Develop content for Statement of Need. Begin discussion of scenarios, futures, and sensitives to inform modeling.
June 1, 2023	Proposed 9:00 – 10:30 AM	Webex	Complete Statement of Need. Discuss ideas for additional model runs.
June 15, 2023	Proposed 9:00 – 10:30 AM	Webex	Assess the degree of consensus around the Statement of Need. Prioritize requested modeling run parameters.
June 29, 2023	9:00 AM – 5:00 PM Lunch provided	In-person workshop, Albuquerque	Build a shared understanding of modeling limitations, discuss model results to date. Document rationale for additional model runs. Enable those who wish to run models with the tools to do so.
July 13, 2023	Proposed 9:00 – 10:30 AM	Webex	Review model results to date. Draft outline for Action Plan.
Aug. 17, 2023	Proposed 9:00 – 10:30 AM	Webex	Review model results to date. Develop an Action Plan.
Sept. 14, 2023	Proposed 9:00 – 10:30 AM	Webex	Assess the degree of consensus around the Action Plan and compare against the Statement of Need. Discuss draft IRP, provide feedback.
Oct. 19, 2023	Proposed 9:00 – 10:30 AM	Webex	Discuss draft IRP, provide feedback. Note areas of agreement, disagreement, and unresolved issues. Decide if an additional (November) meeting is needed.
Dec. 19, 2023	Proposed 9:00 – 10:30 AM	Webex	Reflect on effectiveness, best practices, and suggestions for future IRP stakeholder processes.

Welcome!

Stakeholder Engagement Orientation

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Tuesday, March 28, 2023

9:00 AM Mountain Daylight Time

Purpose of Today's Meeting

- Our primary objective is to create a dialogue among stakeholders to inform the Integrated Resource Plan.
- Discussion topics include:
  - Context for the facilitated stakeholder process
  - Stakeholder introductions and areas of interest
  - Identification of missing voices
  - Feedback on proposed plan for engagement
  - Requests of stakeholders
  - Other topics or questions from stakeholders
  - Next meeting/workshop

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Key Webex Features for our Conversation

- Microphone button - please mute when not speaking
- Raise hand if you wish to speak
- If possible, engage video when speaking, and please identify yourself and the organization you represent
- Type in the chat window to offer ideas to entire group or respond to a specific question





The Facilitated Stakeholder Process is Now Required for Integrated Resource Plans

- November 2022, New Mexico Public Regulation Commission put new procedures in place (Case 21-00128-UT).
- Commission-appointed facilitator enables the stakeholder conversations and produces a report on how this process worked.
- Specific stakeholder deliverables are the Statement of Need and the Action Plan.
- Process required to commence by June 15, 2023 for PNM's filing on Dec. 15, 2023.

GRIDWORKS' Team Members for New Mexico Stakeholder Engagement



Deborah Shields
Project Administrator



Amanda Ormond
Facilitator



Margie Tatro
Facilitator

Gridworks convenes, educates, and empowers stakeholders working to decarbonize our economy.

www.gridworks.org
GRIDWORKS is a non-profit organization.



Jay Griffin
Strategic Advisor & Facilitator



Matthew Tisdale
Strategic Advisor & Facilitator

Stakeholder Introductions

Organizations (roll call from registered participants)

People from each organization in attendance:

- Name
- The topic related to the 20-year plan that you are most interested in

Organizations or people not yet introduced.

Organizations/people who cannot attend today.

Are there organizations not here today who you feel should be in these conversations? (please add suggestions to the “chat”)



Stakeholder Engagement Envisioned to Include Three Phases

March – May	June – August	Sept – Nov IRP Dec. 15
March 28: 9-10:30 AM May 4: 9 – 3 workshop in ALB. May 18: time TBD	June 1: time TBD June 15: Official start of Facilitated Process June 29: possible workshop. July 13 and August 17: times TBD	Sept. 14: time TBD Oct 19: time TBD Dec. 19: time TBD
1: Grounding and Statement of Need	**2: Model Runs and Produce Action Plans**	**3: IRP Reviews**
Grounding Includes: System Requirements, Resource Options, and possibly Load Scenarios. Stakeholder engagement is intense and focuses on the big picture. Builds on 12 prior months of PNM's Public Advisory Process.	Stakeholder Modeling Subgroup runs own models or reviews and engages with utility modelers. Action Plans are developed. Engagement is intense for those with modeling interest/expertise.	Reviews monthly by interested stakeholders for feedback, areas where utility needs input, etc. Stakeholder Engagement is less intense than previous two phases.

You are Invited to Participate as Stakeholders

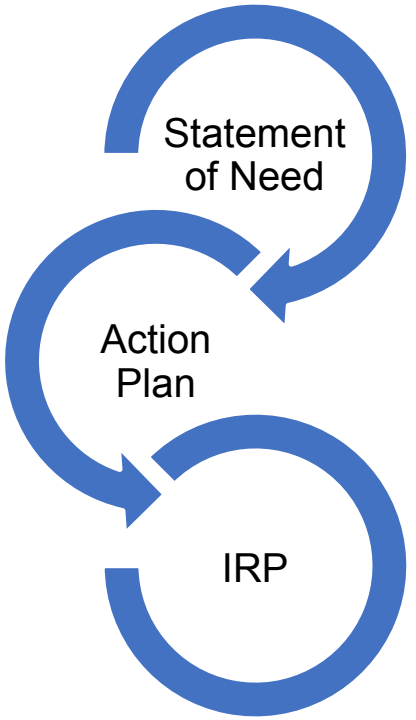
- We request that stakeholders:
  - **Provide actionable feedback regarding Statement of Need, Action Plan, and IRP Drafts.**
  - Attend as many meetings as possible. Review meeting materials in advance. Review summaries from meetings, especially if a meeting is missed.
  - Work offline in working groups, if interested.
  - Consider views and input of other stakeholders.
  - Share experience and expertise, perhaps presenting to the group, as needed.

- Please speak up or send a note to info@gridworks.org if you have an interest in both the PNM and SPS IRP processes as these stakeholder engagement activities are happening in the same timeframe.

Proposed Next Steps

Meet in person on May 4 (9 AM – 3 PM)

- Build a foundation of shared knowledge
- Include missing voices, if any
- Begin working in small groups, for example:
  - Statement of need
  - Modeling scenarios and parameters
  - Modeling results and/or action plan
  - IRP draft reviews
  - Other topics of specific interest



Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

PURPOSE

Create a foundation of shared knowledge while providing opportunities for stakeholders to express their views, hear the views of others, and create input to the Integrated Resource Plan.

KEY OUTCOMES

Grounding knowledge tutorials:

1. Electric system planning requirements
2. Available resources for meeting electric system requirements
3. Modeling overview

Working Groups Input to the IRP:

- First draft or outline of Statement of Need
- Plan to accommodate modeling interests

WORKSHOP AGENDA

8:30 AM – Registration, coffee, and pastries

9:00 AM – Welcome, Purpose and Outcomes for the day

9:15 AM – Tutorial: Statement of Need: System Needs and Requirements*

9:45 AM – Questions, discussion, comments

10:00 AM – Tutorial: 2023 IRP Candidate Resources*

10:30 AM – Questions, discussion, comments

10:45 AM – Break

11:15 AM – Tutorial: 2023 IRP: Modeling and Scenario Analysis Framework, Process Timeline and Scenario Run Requests*

11:45 AM – Questions, discussion, comments

12:00 PM – Plan for afternoon working group sessions

12:15 PM – Lunch (provided)

1:00 PM – Facilitated working group sessions

STATEMENT OF NEED WORKING GROUP: Collect concepts and create outline for Statement of Need

MODELING WORKING GROUP: Develop a plan for stakeholder engagement. Explore modeling parameters. Presentation by and conversation with PNM IRP team on modeling activities. Complete modeling run request sheets.

2:30 PM - Break

2:45 PM – Report out from working groups, next steps, and closing.

3:00 PM – Adjourn

Tutorials and associated Q&A sessions will be recorded for future reference and made available via the **Gridworks website*

Welcome and Thank You for Participating!

Stakeholder Workshop

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, May 4, 2023

9 AM – 3 PM Mountain Daylight Time

Purpose of Today's Workshop

- Our primary objective is to create a dialogue among stakeholders to inform the Integrated Resource Plan.
- Discussion topics:
  - Review regulatory requirements (IRP Rule) and Stakeholder Process
  - Tutorials for shared foundation of knowledge
  - Working group input for the Statement of Need
  - Modeling working group activities
  - Next meetings

Note: Tutorials and Q&A sessions are being recorded and will be available as public information. The links to the recordings will be included in the meeting summary. All information is being posted at New Mexico Energy Planning – Gridworks, https://gridworks.org/initiatives/new-mexico-energy-planning/



Today's Agenda

TIME	TOPIC
9:00	Welcome, Introductions, Stakeholder Process Overview
9:15 RECORDED	Tutorials with Q&A Sessions: • Statement of Need: System Needs and Requirements • 2023 IRP Candidate Resources
10:45	Break
11:15 RECORDED	Tutorial with Q&A Session: Modeling and Scenario Analysis Framework, Process Timeline and Scenario Run Requests
12:00	Plan for Afternoon Working Group Break-outs
12:15	Networking Lunch (lunch provided)
1:00	Working Group Break-outs: • Statement of Need • Modeling
2:30	Break
2:45	Working Groups Reports and Closing
3:00	Adjourn

GRIDWORKS' Team Members for New Mexico Stakeholder Engagement



Deborah Shields
Project Administrator



Amanda Ormond
Facilitator



Margie Tatro
Facilitator

Gridworks convenes, educates, and empowers stakeholders working to decarbonize our economy.

www.gridworks.org
GRIDWORKS is a non-profit organization.



Jay Griffin
Strategic Advisor & Facilitator



Matthew Tisdale
Strategic Advisor & Facilitator

GRIDWORKS

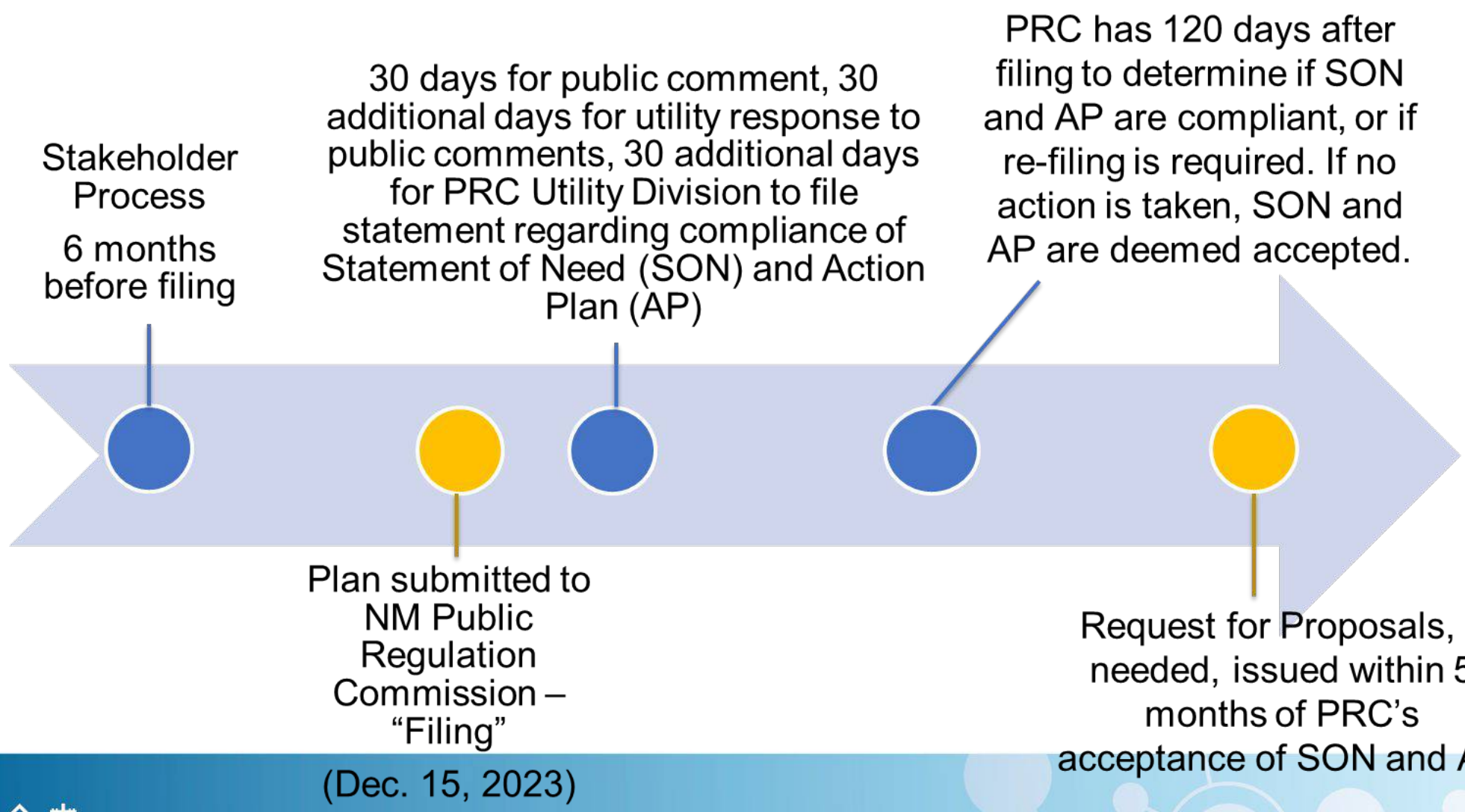
Stakeholder Introductions

Please take 5 minutes to go around the table, each person offering:

- Your Name
- Your Organization
- Your Top Interest in this IRP

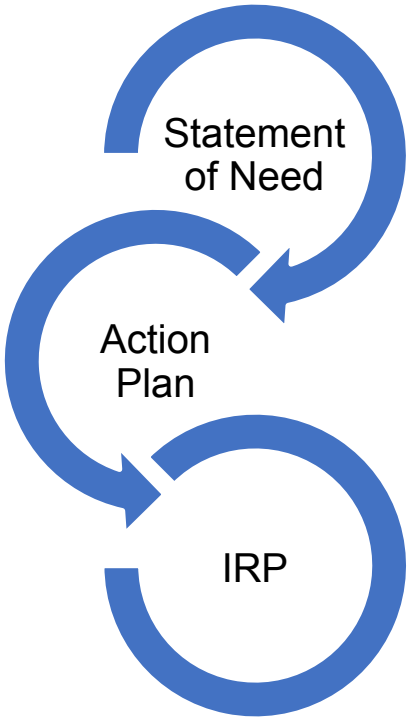


Sequence of Steps in the Integrated Resource Plan Process



The Facilitated Stakeholder Process is Now Required for Integrated Resource Plans

- November 2022, New Mexico Public Regulation Commission put new procedures in place (Case 21-00128-UT).
- Commission-appointed facilitator enables the stakeholder conversations and produces a report on how this process worked.
- Specific stakeholder deliverables are the Statement of Need and the Action Plan.
- Process required to commence by June 15, 2023 for PNM's filing on Dec. 15, 2023.



Stakeholder Engagement Includes Three Phases

March – May	June – August	September - December
March 28: 9 - 10:30 AM **May 4: 9 – 3 workshop** May 18: 9 - 10:30 AM	June 1: 9 -10:30 AM June 15: 9 -10:30 AM **June 29: 9 - 3 workshop** July 13: 9 -10:30 AM August 17: 9 - 10:30 AM	Sept.14: 9 -10:30 AM Oct. 19: 9 -10:30 AM Dec. 19: 9 -10:30 AM

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews and Process Feedback

Introducing the PNM IRP Team

PNM TEAM MEMBERS

- Nick Phillips
- Sarah Baxley
- Shane Gutierrez
- Phillip Metzger
- Kelly-Renae Huber

PNM CONSULTANT TEAM MEMBERS

- Nick Wintermantel
- Kevin Cox
- Nick Schlag

Building a Foundation of Shared Knowledge

Tutorials:

- Statement of Need: System Needs and Requirements
- 2023 IRP Candidate Resources
- 2023 IRP: Modeling and Scenario Analysis Framework, Process Timeline, and Scenario Requests

GRIDWORKS

Questions Following Each Tutorial…please wait for the microphone, then

1. Grounding: What stands out for you?

2. Reflective: What concerns do you have?

3. Interpretative and Decisional: Where do you need more information or wish to explore further?

Preparing for Working Group Breakout Sessions

Time to Roll Up our Sleeves

Statement of Need Working Group (Room #103)

Develop ideas and outline for the Statement of Need

Modeling Working Group (Room # 104)

Learn more about modeling & Organize for modeling engagement



TIMETABLE

1:00 Convene Working Groups
- Select Spokesperson and Notetaker
- Facilitator Manages the Process

2:30 Break

2:45 Reassemble for Report Out and Closing

REPORT OUT

1. Conclusions
2. Recommended next steps
3. Identify any missing voices



Closing Session

Working Group Reports

Next Steps

Feedback

Working Group Reports

REPORT OUT

1. Conclusions
2. Recommended next steps
3. Identify any missing voices



Statement of Need Working Group

Modeling Working Group

Next Steps and Announcements

Next meeting

- May 18 via WEBEX, 9:00 – 10:30 AM
- Please register on PNM's IRP website
- Watch for information from Deborah Shields (GRIDWORKS)
- Topics include Statement of Need and Modeling Activities Update

Note: SPS IRP Stakeholder Process begins May 16; filing date for IRP is Oct. 15. Please let us know if you are interested in this stakeholder process.

We are Interested in your Feedback

Please complete and leave at the registration table on your way out.
THANK YOU!

For today's workshop:

1. What did you find useful?_____
2. What was not useful?_____
3. What would you suggest be done differently for the next meeting or workshop?_____

_____

_____

4. Other feedback for us? _____

_____

_____

Feel free to email info@gridworks.org if you have other feedback.

Thank you for your engagement!

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

STATEMENT OF NEED: SYSTEM NEEDS AND REQUIREMENTS

MAY 4, 2023



AGENDA

- **Statement of Need**
- **Essential planning requirements**
    - Resource adequacy and reliability
    - Environmental requirements
    - Regulatory requirements
    - Cost minimization
- **Incremental planning requirements**
    - Grid of the past vs. grid of the future, and expectations for a carbon-free grid

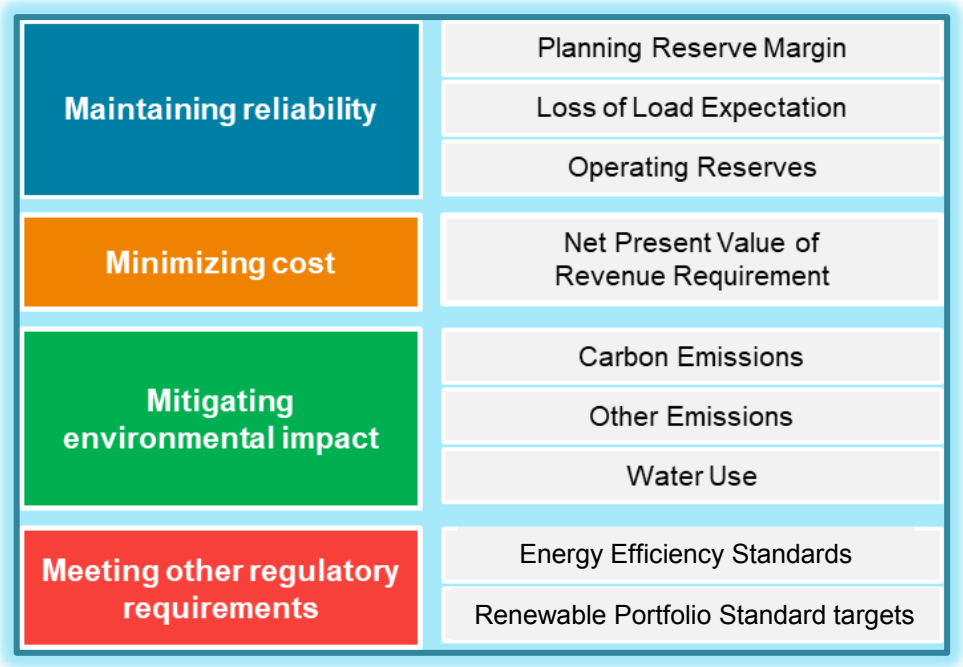
STATEMENT OF NEED

Statement of Need 17.7.3.10

- 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.
- 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.

ESSENTIAL PLANNING REQUIREMENTS

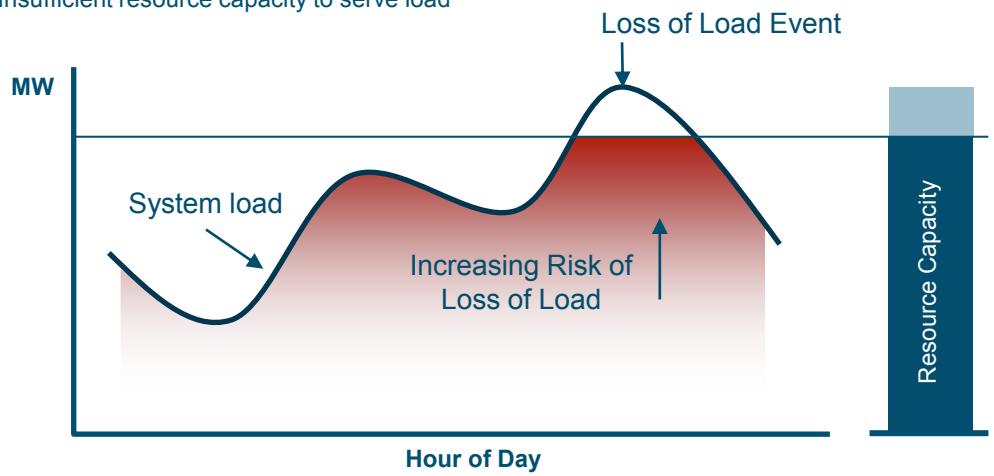
Planning objectives



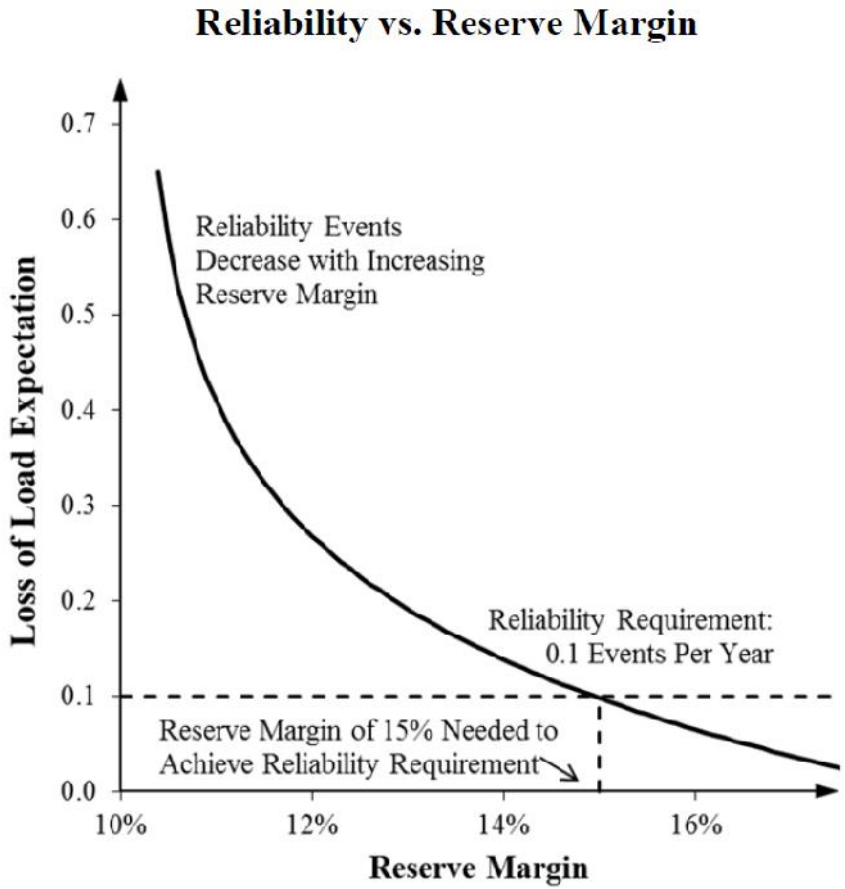
- Modeling framework uses Loss of Load Expectation (LOLE) modeling to calculate resource adequacy requirements and test portfolios for reliability
- In addition to energy and demand requirements, environmental and regulatory requirements dictate modeling inputs for capacity expansion and production cost modeling

WHAT IS RESOURCE ADEQUACY?

Loss of Load Example
Insufficient resource capacity to serve load



PNM targets:
0.1 LOLE
16% PRM



NERC Definition of Resource Adequacy:

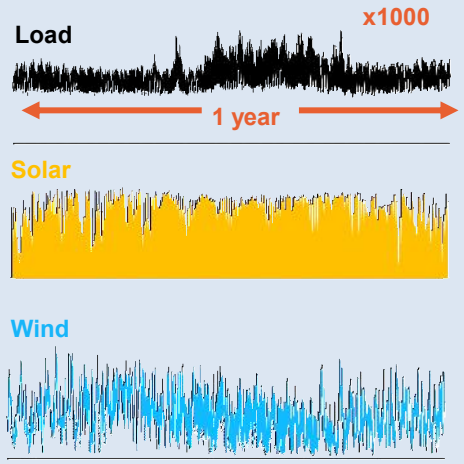
"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

Source: NERC Glossary of Terms

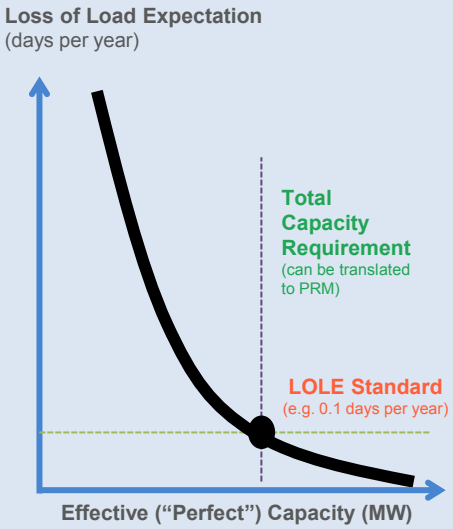
PNM Talk to us. PNM.com

BEST PRACTICES IN RESOURCE ADEQUACY ANALYSIS

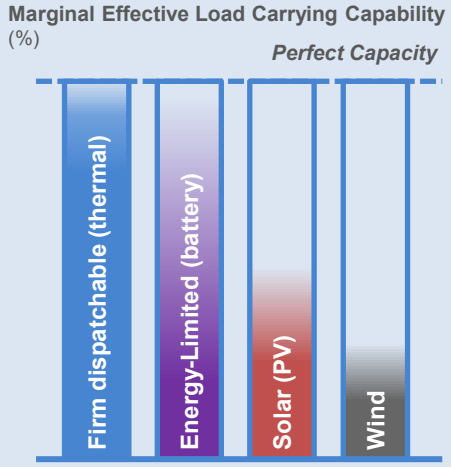
Loss of Load Probability modeling evaluates resource adequacy across all hours of the year



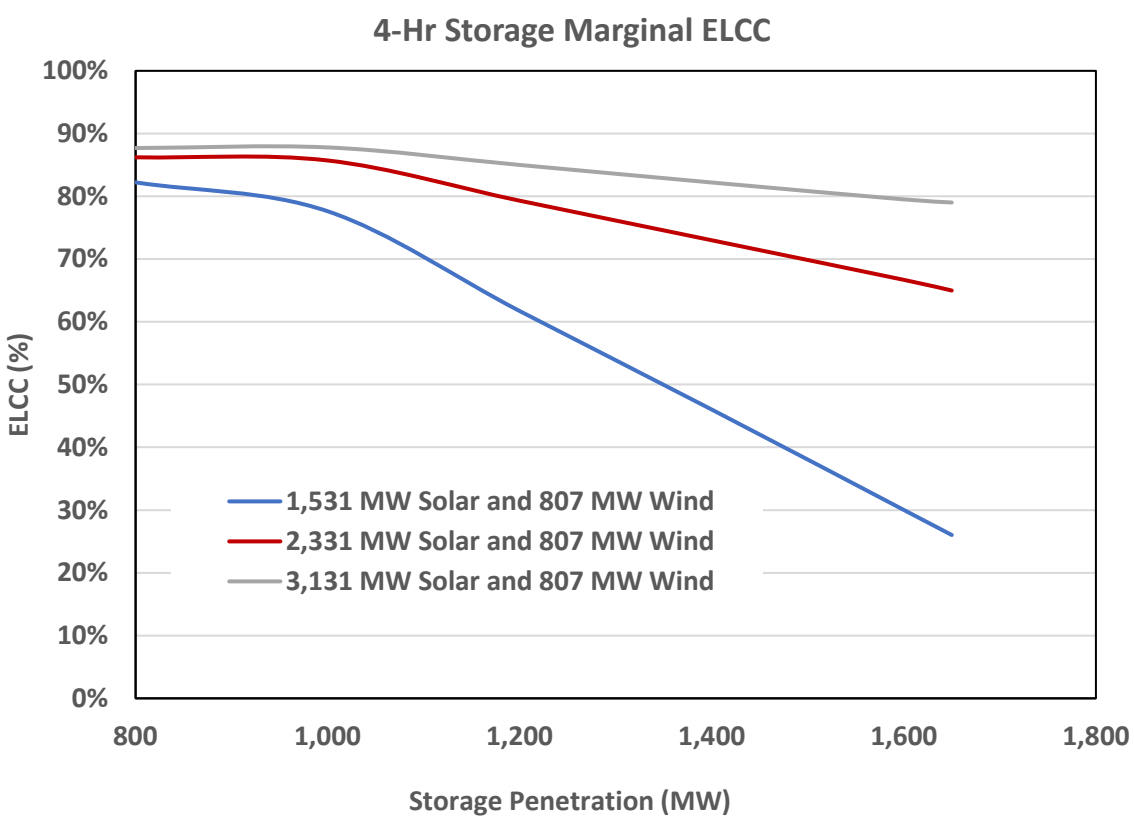
Amount of perfect capacity needed to achieve the desired level of reliability is identified

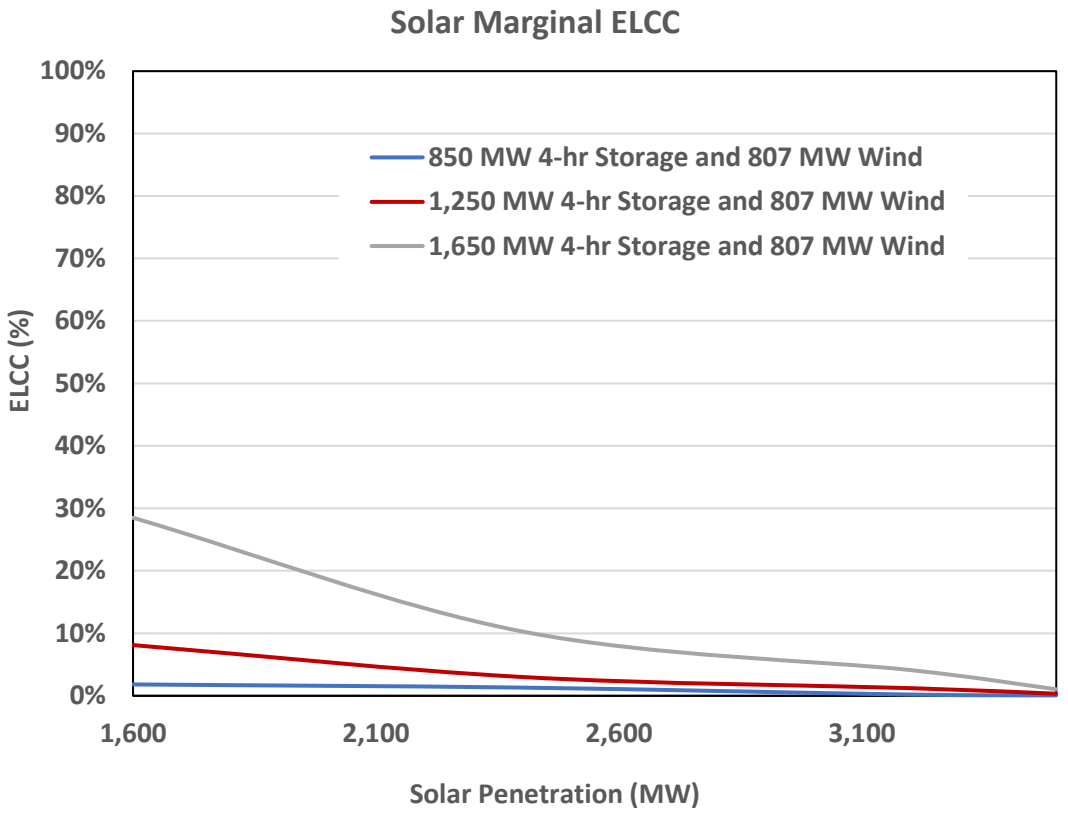


Effective Load Carrying Capability is calculated based on resource contributions to reliability



SUMMARY OF SELECTED ELCCs





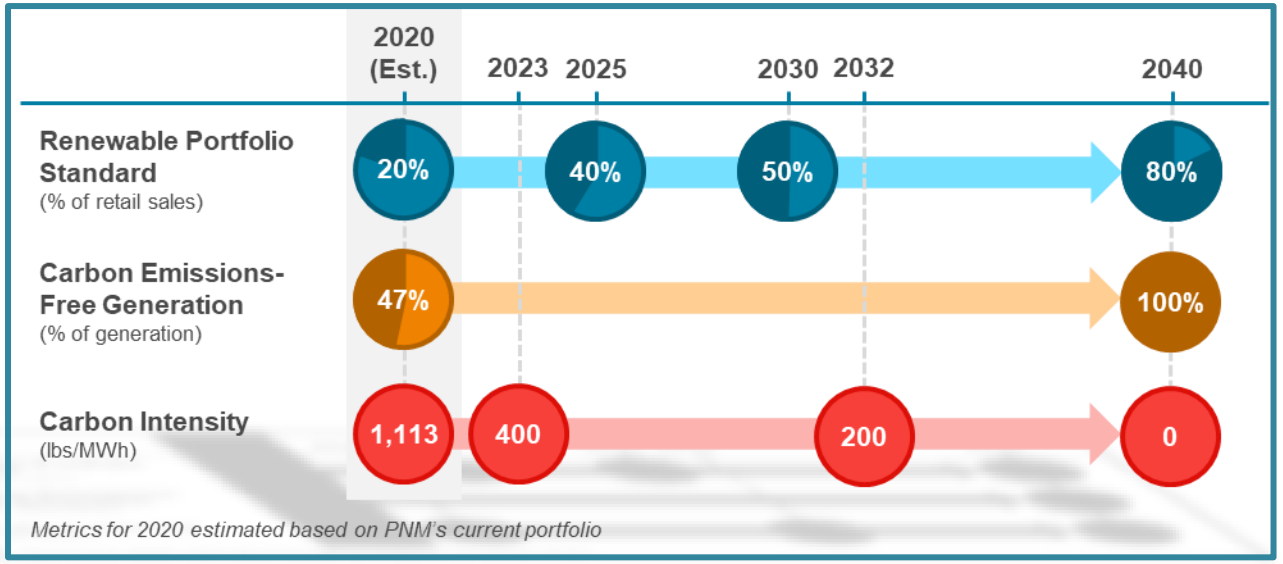
Modeled ELCCs must reflect installed capacities and interaction effects between resources – ELCCs are outputs of reliability modeling and inputs into the capacity expansion model

Talk to us.

ENVIRONMENTAL REQUIREMENTS SET BY NEW MEXICO ENERGY TRANSITION ACT

In 2019, the governor signed into law the Energy Transition Act (ETA), which established significant long-term targets for utilities within the state:

- By 2040, all retail sales must be supplied by 80% renewable generation; and
- By 2045, all retail sales must be supplied by 100% carbon emissions-free generation



ETA requirements are constraints in the capacity expansion optimization and production cost modeling

- Other environmental metrics are tracked and reported, though they do not provide constraints for EnCompass capacity expansion optimization and production cost modeling
  - Emissions: CO (carbon), SO2 (sulfur dioxide), NOx (nitrogen oxides), PM 2.5 (fine particles), Hg (Mercury)
  - Water usage

OTHER REGULATORY REQUIREMENTS

Legislation:

- **New Mexico Public Utility Act – 62-3-1 et.seq. NMSA**
  - Establishes that utilities are affected with the public interest and require public regulation and supervision in order to prevent unnecessary duplication and economic waste between utility systems, and provide proper utility services at fair, just, and reasonable rates
- **Efficient Use of Energy Act – 62-17 NMSA**
  - Under the Efficient Use of Energy Act (EUEA), PNM is required to implement load management and energy efficiency programs subject to cost effectiveness as measured using the Utility Cost Test (UCT).
  - The EUEA and subsequent amendments have established energy savings goals for these programs; the most recent amendments in 2019 established goals for 2021-2025 of 5% of 2020 retail sales, or approximately 400 GWh.
- **Energy Transition Act – 62-18 NMSA**
  - Establishes carbon emissions and RPS targets for NM utilities
  - Provides support for communities impacted by coal plant retirements, including mandated deployment of renewable resources in San Juan County

NMPRC Rules:

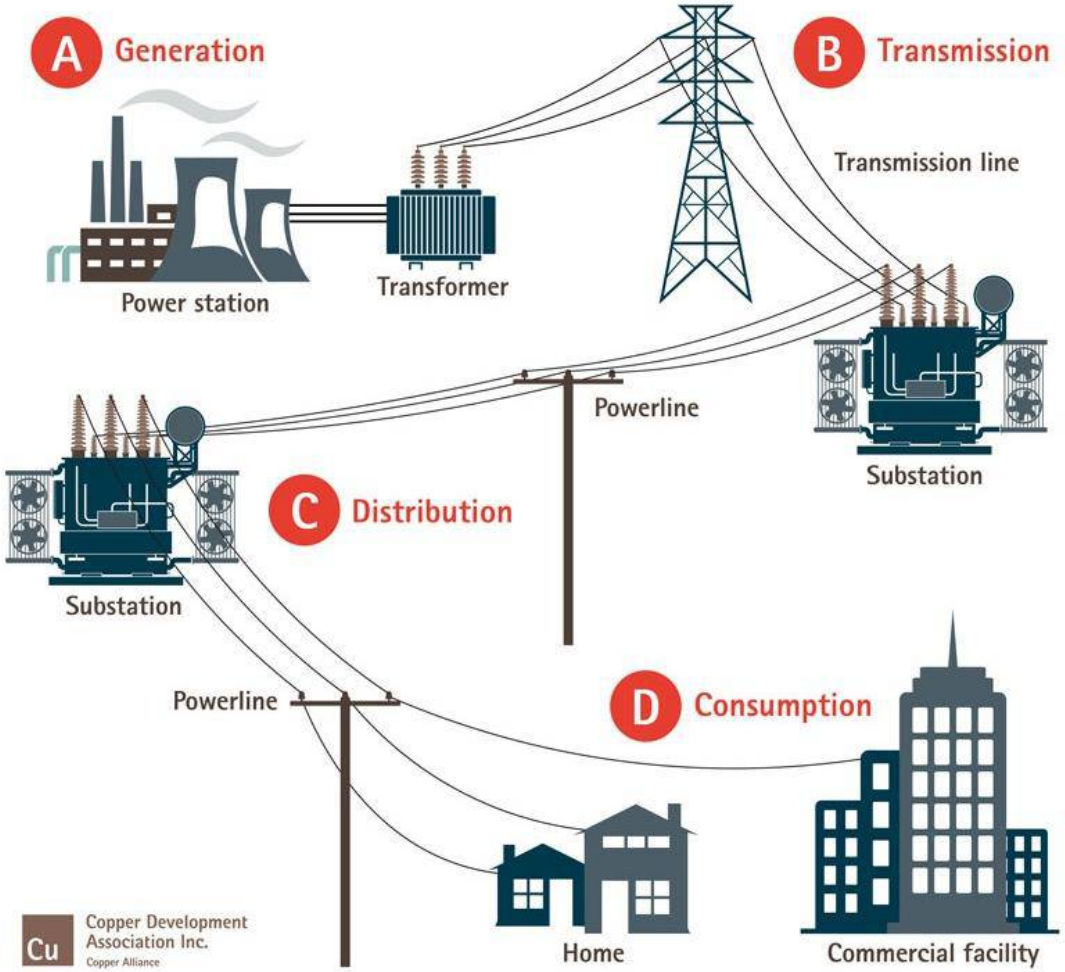
- **Integrated Resource Plans for Electric Utilities – NMAC 17.7.3**
  - Establishes certain items to be included in IRP report
  - Outlines Facilitated Stakeholder Process
  - Defines Statement of Need and Action Plan
  - Outlines Request for Proposal process and role of independent monitor
- **Renewable Energy for Electric Utilities – 17.9.572 NMAC**
  - Stipulates that each public utility develop an annual Renewable Energy Act plan to comply with RPS standards for a given year, and that demonstrates reasonable and consistent progress toward meeting the RPS
  - Establishes procedures for renewable energy procurement and outlines reasonable cost analysis
  - Lays out guidelines for utility annual renewable energy act plans and cost recovery
  - Outlines means by which compliance is attained and measured
- **Energy Efficiency – 17.7.2 NMAC**
  - Implementation of Efficient Use of Energy Act establishing criteria to evaluate and implement cost-effective measures or programs that reduce energy demand and consumption
  - Specifies how annual program funding is to be determined, how new programs and those previously approved will be cost-effective, and establishes annual incentive criteria
  - Lays out guidelines for different program types, as well as criteria for measurement and verification

COST MINIMIZATION

1. **EnCompass capacity expansion optimization and production cost modeling provide portfolios that meet the following constraints:**
    - Load and energy requirements
    - Reliability requirements
    - Environmental requirements – CO2 intensity and RPS targets
    - Energy efficiency requirements (energy efficiency programs)
2. **Portfolios are then compared on the basis of net present value of revenue requirements (NPV RR); most cost-effective portfolios (MCEPs) are the lowest-cost portfolios that satisfy all requirements**

For the 2023 IRP, the 2-3 lowest-cost portfolios will undergo resiliency analysis

THE TRADITIONAL SYSTEM



- Power generated at large central stations and delivered to customers through transmission and distribution system
- PNM has full control and visibility of system
- PNM balances system by matching generation to load
- Traditional generators are fully dispatchable and provide grid services along with energy

PNM Talk to us. PNM.com

TOMORROW'S GRID: A GRID OF GRIDS



An Interconnected Power System Balancing Forecasted Resources with Dispatchable Loads

Source: "The Future of the Electric Grid and the Role of Energy Storage" Electric Power Research Institute, May 24, 2016

PNM expects a carbon-free grid to be:

1. Sustainable
2. Reliable
3. Resilient
4. Affordable

PNM Talk to us. PNM.com

2023 IRP CANDIDATE RESOURCES

MAY 4, 2023



CONTENTS

Possible future resource options

- Renewable energy resources
- Thermal energy resources
- Energy storage resources
- Carbon capture technologies
- Distributed energy resources, Energy Efficiency, and Demand Response

Appendix: supplemental information

- Other technologies not modeled in 2023 IRP

POSSIBLE FUTURE RESOURCE OPTIONS

Near/mid-term (technology could be deployed today or in the next 5-10 years)

Longer term (technology deployment >10 years)

Renewable energy resources:

- Solar PV
- Wind
- Geothermal power

Thermal energy resources:

- Aeroderivative combustion turbine
- Linear generator

Energy storage resources:

- Lithium-ion battery
- Redox-flow battery
- Iron-air storage
- Pumped-hydro storage
- Compressed/liquified air energy storage
- Thermal energy storage
- Green hydrogen

Carbon capture:

- Post combustion carbon-capture from flue gas using chemical absorption
- NET power plant

Distributed energy resources:

- BTM PV & storage
- Energy efficiency
- Demand response

RENEWABLE ENERGY RESOURCES

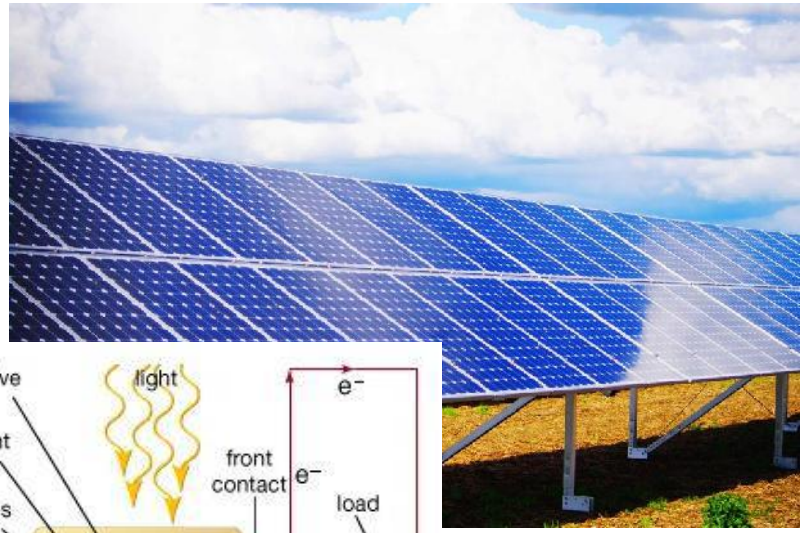
SOLAR PV

Operation:

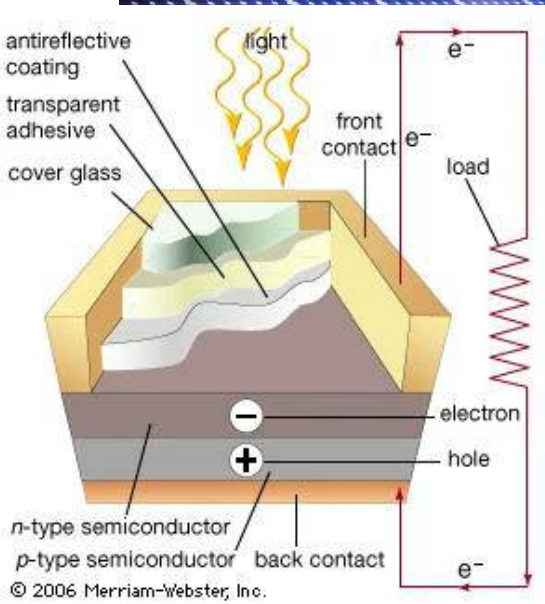
- Conversion of sunlight into electricity through semiconducting materials
- Semiconductor material absorbs light and transfers energy to electrons within the material
- Charged electrons flow through the material as an electrical current, which is extracted though conductive metal contacts within the solar cells
- Semiconductors create DC electricity, which is converted to AC power output using an inverter
- PV modules consist of multiple cells; PV systems include mounting structures, modules, and power electronics devices

Considerations:

- Renewable, carbon-free power
- New Mexico solar resource is excellent
- ITC/PTC eligibility
- Variable energy resource with production occurring only during daylight hours; storage needed for solar to contribute to decarbonization of offpeak/nighttime hours
- Potential risks around high concentration of inverter-based resources
- Technology is commercially available and widely deployed today; development time is typically less than 2 years
- 2025 cost of $1,259/kW (Siemens estimate for tacking system, 2022 $, assumes ITC)*



Source: Encyclopedia Britannica



* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Source: Energy.gov "*Solar Photovoltaic Cell Basics*"

WIND

Operation:

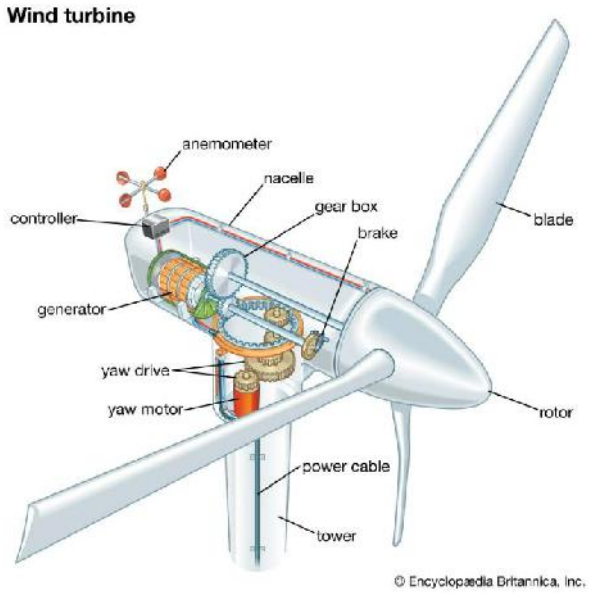
- Electricity is produced from the aerodynamic force of the rotor blades of the turbine; the translation of aerodynamic force to rotation creates electricity
- As wind moves across the blade, air pressure on one side of the blade decreases, causing a pressure differential between the two sides of the blade
- The pressure differential creates lift on one side of the blade, and drag on the other – this causes the rotor to spin
- The rotor connects to a generator, either directly or through a gearbox

Considerations:

- Renewable, carbon-free electricity
- New Mexico wind has a high average capacity factor (>40%)
- ITC/PTC eligibility
- Wind can contribute to decarbonization of offpeak/non-solar hours
- Variable energy resource that must be balanced
- Transmission constraints would require transmission build to access significant amounts of new wind
- Technology is commercially available and widely deployed today; development time is typically less than 2 years
- 2025 cost of $1,883/kW (Siemens estimate for onshore wind, 2022 $, assumes PTC)*



Source: Microsoft stock images



* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Source: Energy.gov "*How Do Wind Turbines Work?*"

GEOTHERMAL POWER

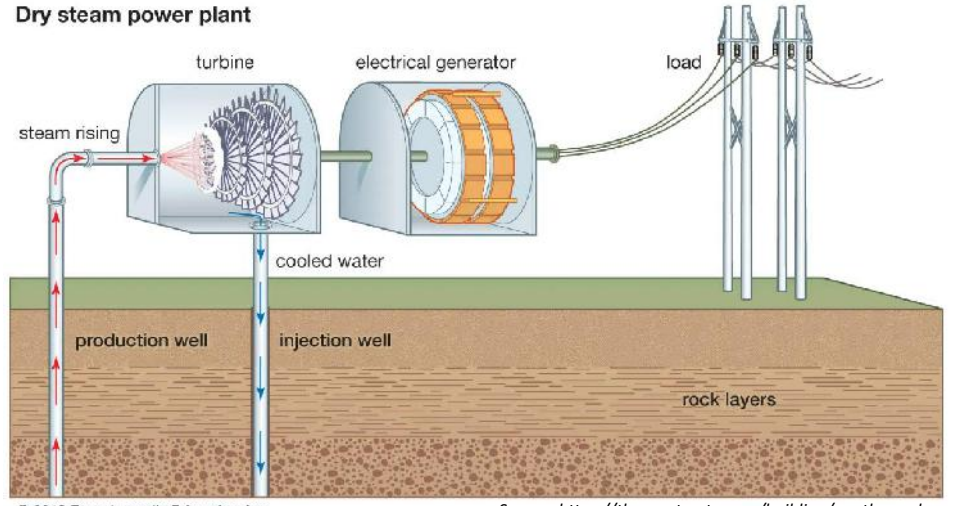
Operation:

- Geothermal power plants generally use steam to produce electricity – the steam is created using geothermal energy
- There are three types of geothermal power plants: dry steam (draws on geysers, and is very rare), flash steam (most common, see below), and binary cycle (in which water heats a secondary working fluid)
- Flash steam plants draw on geothermal reservoirs of water (where water temperatures can be greater than 360°F); high pressure water flows upward through a well, and as it rises and the pressure decreases, it begins to boil and evaporate – the separated steam is used to power a turbine generator, and leftover water is injected back into the reservoir
- Enhanced geothermal systems access heat deeper underground – these wells are up to ~7 km deep – and utilize oil drilling techniques to fracture heated rock for easier pumping of water

Considerations:

- Carbon-free, dispatchable renewable energy source
- ITC/PTC eligibility
- New Mexico has favorable Geothermal resource in western parts of the state – though economics are locationally dependent
- Longer development lead-time (5+ years)
- Commercially viable and deployed technology
- Capital cost of standard geothermal plant ~$7,800-9,800/kW (2030 cost in 2022 $, E3 analysis, does not include IRA impacts)
- Capital cost of enhanced geothermal plant ~$9,000-52,000/kW (E3 analysis; 2030 cost in 2022 $, does not include IRA impacts)





Source: *https://theconstructor.org/building/geothermal-energy-working-buildings/562287/*

Sources: NREL.gov "*Geothermal Electricity Production Basics";* E3 *CPUC IRP Zero-Carbon Technology Assessment*

THERMAL ENERGY RESOURCES

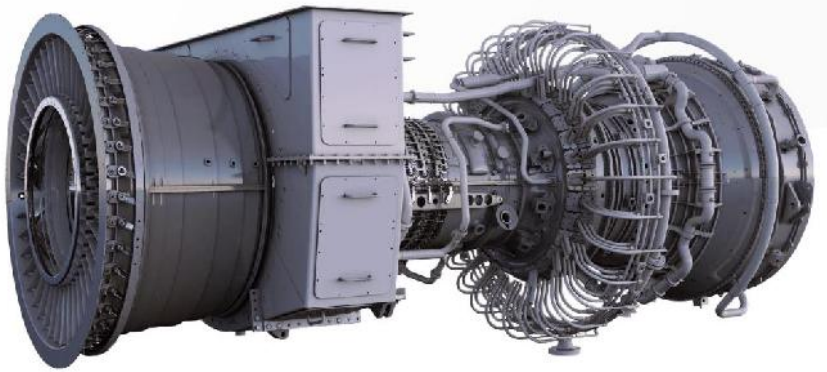
AERODERIVATIVE GAS COMBUSTION TURBINE

Operation:

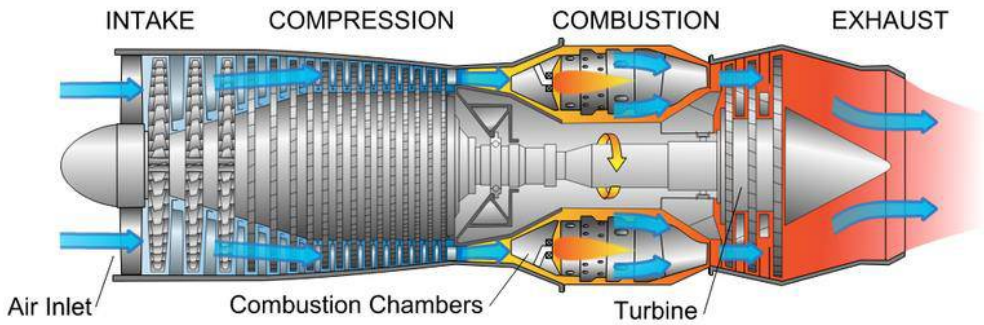
- Often used in a peaking capacity, combustion turbines are designed to ramp quickly
- Air is drawn into the front of the unit, compressed, and sent to the combustion chamber, where it is mixed with fuel
- This mixing results in immediate combustion to produce a high temperature, high pressure gas steam that is expanded through the turbine section
- The turbine section is comprised of alternating stationary and rotating blades; as hot gas expands through the turbine, the rotating blades spin
- The spinning blades drive a generator to produce electricity, and the compressor to draw more pressurized air into the combustion chamber

Considerations:

- Fully dispatchable, fast start time (<5 minutes), with fast ramp capability
- Use of natural gas in near-term; fuel flexibility would allow for use of a natural gas/hydrogen blend with potential conversion to burn 100% hydrogen in the future (though some uncertainties around this remain given the specifications and configuration necessary for 100% H2 combustion)
- Commercially available and proven at utility scale; development and construction period up to ~5 years
- 2025 capital cost of $1,469/kW (Siemens estimate for conventional Aeroderivative turbine, 2022 $)*



GE LM6000; source: GE



Source: https://energyeducation.ca/encyclopedia/Gas_turbine

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Source: Energy.gov *"How Gas Turbine Power Plants Work"*

LINEAR GENERATOR UNITS

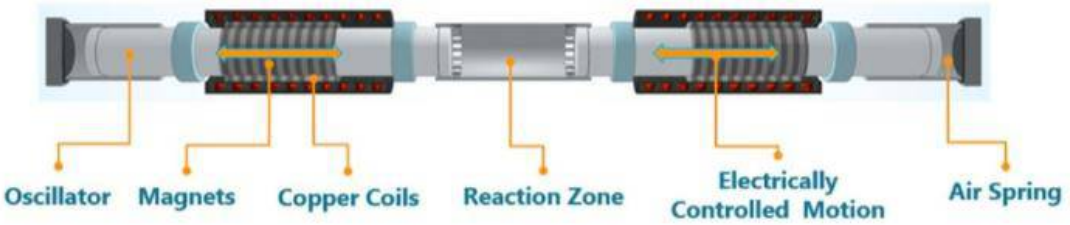
Operation:

- A linear generator is comprised of two oscillators that move linearly between a center reaction zone and two outer air springs
- Magnets on the oscillators interact with surrounding copper coils for electricity production as the oscillators move back and forth
- Air and fuel are compressed in the center reaction zone, causing a low-temperature flameless reaction, which pushes the oscillators out, through the copper coils, generating electricity and compressing the outer air springs
- The compression of the outer air springs is then used to send the oscillators back towards the center zone, compressing air and fuel and causing a reaction, beginning a new cycle

Considerations:

- Near zero NOx emissions
- Fully dispatchable thermal resource
- Fuel flexibility: allows seamless witch between natural gas, biogas, hydrogen & other fuels
- Modular
- ITC eligible
- Deployed at small scale today; relatively short development and construction period (<2 years)
- Majority of equipment can be repurposed at end of life
- Similar to battery storage, can be used to firm renewable energy and provide ancillary services
- Suitable to local applications reducing the need for transmission
- Capital cost of $2,068/kW (Siemens estimate, 2022 $; Mainspring reports most projects have PPA structure)*





* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Source: Mainspring Energy

Source: www.mainspringenergy.com; Greentech Media

ENERGY STORAGE RESOURCES

LITHIUM-ION BATTERY

Operation:

- A battery is comprised of an anode, a cathode, a separator, an electrolyte, and both positive and negative current collectors (the positive and negative terminals)
- The cathode and anode store lithium, and release lithium ions when the battery is charging and discharging, respectively
- The separator allows charged lithium ions to flow within the battery, but blocks the flow of electrons inside the battery; electrons must instead flow through the external circuit to maintain charge neutrality at each electrode
- When charging, electrons from the external circuit travel from the positive current collector to the negative current collector, and positively charged lithium ions move through the electrolyte from the cathode to the anode (crossing the separator)
- When discharging, the process works in reverse; the lithium ions travel through the electrolyte from the anode to the cathode, and electrons travel through the external circuit from the negative current collector to the positive current collector

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

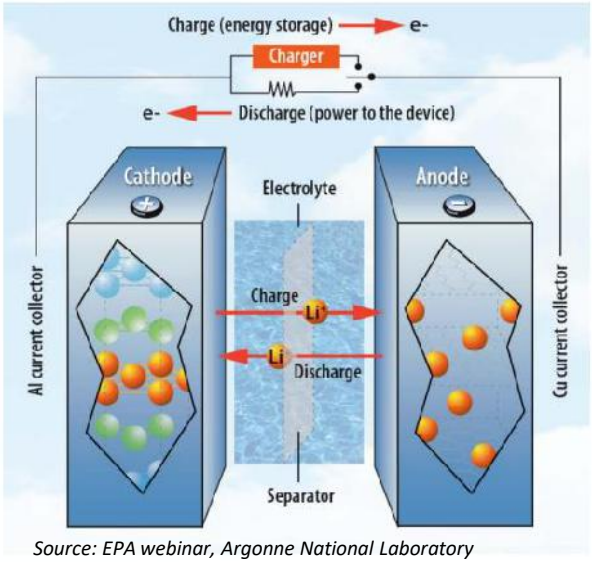
Source: Energy.gov "*How Lithium-ion Batteries Work*"

Considerations:

- Widely deployed grid-scale storage technology with relatively short development and construction lead-time (<3 years)
- ITC eligible
- Modular, can be deployed at transmission and distribution levels
- High Round-trip-efficiency (RTE) of ~85%
- Fast-ramping, can balance renewable output and provide grid reliability services
- Ability to optimize energy density vs. power density (capacity vs. duration)
- Best for shorter-duration solutions (30 minutes to four hours), may not be most cost-effective long-duration solution since inventory has little scale economies
- Operational uncertainties over long term
- 2025 capital cost of $1,402/kW (Siemens estimate for 4-hour storage in 2022 $)*



Source: GE (https://www.ge.com/news/reports/leading-charge-battery-storage-sweeps-world-ge-finding-place-sun)



Source: EPA webinar, Argonne National Laboratory (https://www.epa.gov/sites/default/files/2018-03/documents/spanenberger_epa_webinar_-_3-22-18_-_argonne.pdf)

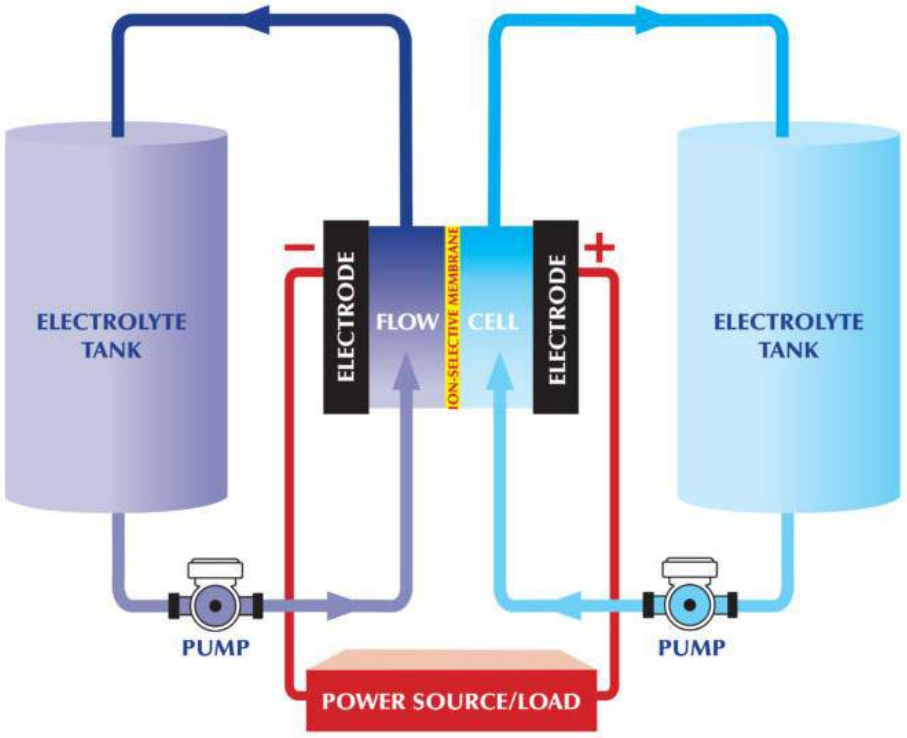
REDOX-FLOW BATTERY

Operation:

- Flow batteries use a chemical reduction-oxidation (redox) process to generate electricity – potential energy is stored (dissolved) in electrolyte solutions
- An anolyte and catholyte (chemical electrolyte solutions) are held in tanks separated by a stack of electrochemical cells
- Flow batteries are differentiated from lithium-ion batteries in that the power and energy components are separate and can be scaled independently; energy density is a product of the volume of the electrolyte, while power capacity is a function of the cell stack size
- When the electrolyte solutions are pumped through the cell stack (each flowing in their own respective loops and separated by a membrane within the cell stack), the resulting ion transfer at the membrane induces an electric current to flow through the external circuit
- During charging, electrons are released in the positive electrolyte (oxidation) and travel though the positive electrode to the negative electrode, where electrons are absorbed into the negative electrolyte (reduction)
- When discharging, the movement of ions from the anolyte to the catholyte induces electrons to flow through an external circuit

Considerations:

- Generally used for longer-duration applications due to economics (4+ hours)
- ITC eligible
- Long cycle life, can be fully discharged with little to no degradation
- Fast-ramping
- Decoupled power and energy
- Most components can be recycled
- Lower efficiency than lithium-ion (~70% vs. ~85%)
- 2025 capital cost of $4,254/kW (Siemens estimate for 10-hour system in 2022 $)*



Source: Flow battery forum (https://flowbatteryforum.com/what-is-a-flow-battery/)

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: Energy Storage Association "*Redox Flow Batteries";* Clean Energy Institute University of Washington *"Flow Batteries";* CleanTechnica *"Vanadium Flow Battery Benefits for Our Future";* Powermag.com *"Flow Batteries: Energy Storage Option for a Variety of Uses"*

IRON-AIR STORAGE

Operation:

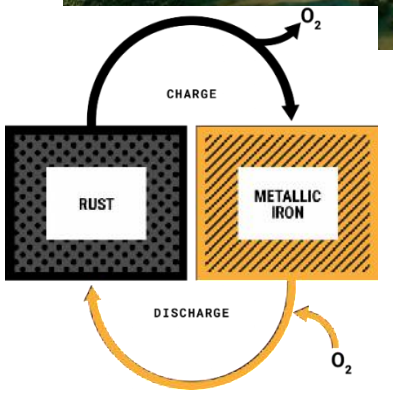
- When discharging, battery "breathes" in oxygen from the air, converting iron to rust
- When charging, the process is reserved when an electrical current converts the rust back to iron
- Modular: each battery module is the size of a side-by-side washer/dryer and contains ~50 cells; each cell contains the iron and air electrodes and is filled with a water-based electrolyte
- Scalable: modules are grouped together in enclosures, many enclosures grouped together to create MW-scale power blocks; 1 MW requires ~0.5 acres of land (lowest density)

Considerations:

- Modular and scalable without specific siting requirements other than adequate space
- ITC eligible
- Three pilot projects underway, utility scale applications yet unproven; earliest large-scale deployment likely in the late 2020's
- Can reduce renewable generation curtailment and firm variable renewable generation over days (100 hours of storage capability)
- Slower start time and ramp than li-ion; lower efficiency than li-ion (~50%)
- Cannot optimize between capacity and energy – all capacity has fixed storage duration
- Peaker replacement use case
- Siemens estimates 2025 capital cost of $2,228/kW (2022 $)*



Source: www.formenergy.com



* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: Form Energy; Energy Storage News, "*Renewables as baseload energy: Form Energy's multi-day storage seeks to replace gas and coal*"

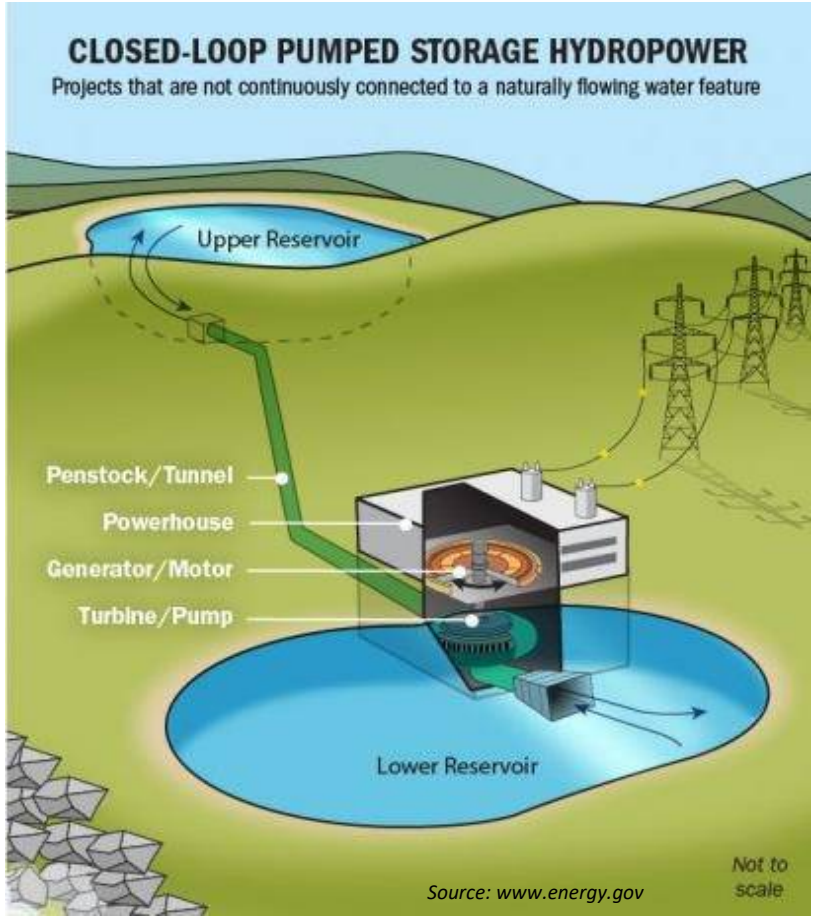
PUMPED-HYDRO STORAGE

Operation:

- Pumped-hydro storage can be a closed-loop or open-loop system; closed-loop consists of two independent reservoirs, while an open-loop system is connected to a naturally flowing water feature
- Charging process consists of pumping water (using electricity) from a lower reservoir to the upper reservoir
- Discharging consists of power generation from water moving through a turbine as it flows from the upper reservoir to the lower reservoir
- Beyond initial fill, water usage mainly consists of evaporative losses – pumped hydro RFI responses generally indicate evaporate losses are ~5% of initial fill per year

Considerations:

- A form of long-duration storage, pumped-hydro can have 70+ hours of duration (depending on size of reservoir)
- ITC eligible
- Pumped-hydro storage has a technology readiness level of 9 and is at full commercial application today; longer development and construction timeframe of 5+ years, earliest deployment late 2020's
- RTE >80%
- This type of plant has specific siting requirements (elevation differential), and there is some uncertainty around the feasibility of a hydro facility in the desert (though reservoirs can be covered)
- Siemens 2025 capital cost estimate of $3,577/kW for 10-hr system (2022 $)*



* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022
Source: Energy.gov "*Pumped Storage Hydropower*"

COMPRESSED AIR/LIQUIFIED AIR ENERGY STORAGE

Operation of compressed air energy storage (CAES) system:

- When charging, power from the grid is used to run a multi-state motor-compressor to compress ambient air – heat generation in the compression process can be captured for later use in the expansion process (adiabatic CAES)
- Compressed air is stored under high pressure – usually in underground caverns (salt, rock)
- To deploy energy, the pressurized air is released from the cavern and expanded in multiple stages – the air cools as it expands, and so heat must be added as the pressure falls; the heating and expansion process drives a turbine generator
- In an adiabatic process, expansion uses recovered heat from compression; in a diabatic process, natural gas or other fuel is added for heat during expansion

Operation of liquified air energy storage (LAES) system:

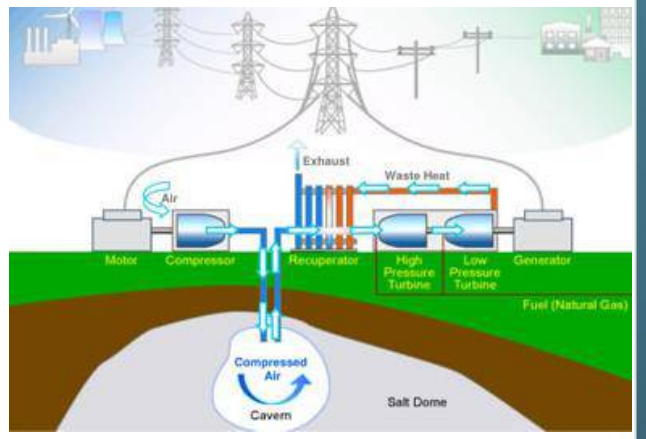
- Charging process consists of chilling and liquefying ambient air using an electric air liquefier – this creates heat, which can be stored for later use in the generation process
- Liquid air is stored in tanks at low pressure (similar to liquid nitrogen or LNG storage)
- To generate electricity, liquified air is drawn from tanks, pumped to high pressure, evaporated and superheated to ambient temperature – this high-pressure gas is used to drive a turbine generator
- Waste cold from the expansion stage can be captured for use in liquefaction process

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: Energy Storage Association "*Compressed Air Energy Storage (CAES)";* Highview Power

Considerations:

- CAES requires large storage volume and specific siting; LAES has no geographical constrains on location
- Both CAES and LAES use technologies that are mature and rely on established power-generation processes and off-the-shelf equipment; both can be modular and scalable
- Both ITC eligible
- Only diabatic CAES proven at large scale
- Longer development and construction period of 5+ years
- RTE of ~50-70% depending on design
- Waste heat/cold can from industrial processes can be utilized
- Siemens estimates a 2025 CAES capital cost of $1,472/kW for a 100-200 MW, 30-hr system (2022 $)*
- Siemens estimates a 2025 LAES capital cost of $3,147/kW for a 100-200 MW, 8-hr system (2022 $)*



Source: https://phys.org/news/2010-03-compressed-air-energy-storage-renewable.html



Source: https://highviewpower.com/technology/

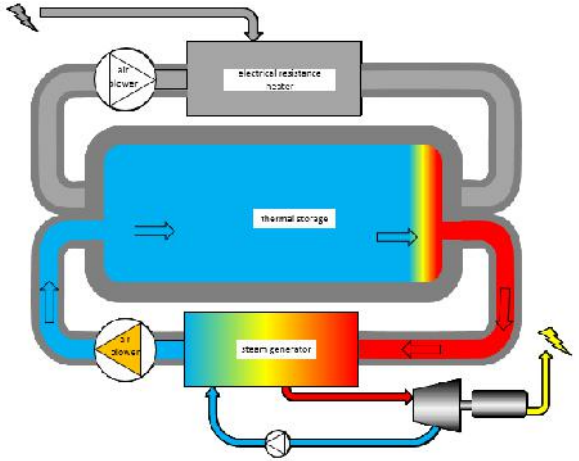
THERMAL ENERGY STORAGE

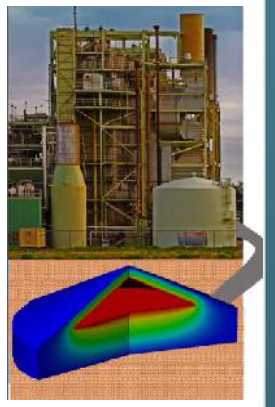
Operation:

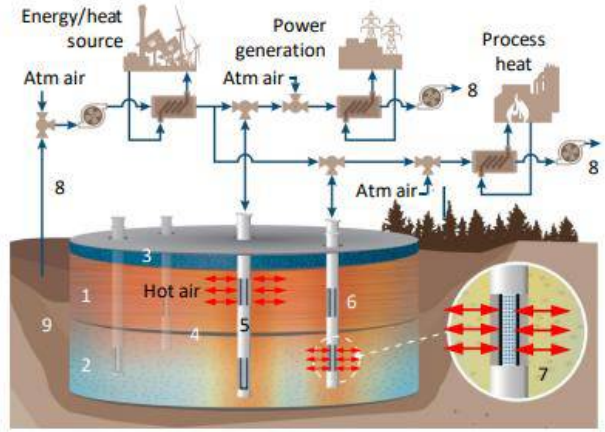
- There are many types of thermal storage utilizing a wide array of technologies
- Generally, thermal storage systems utilize inexpensive and safe materials; storage medium can be contained in tanks, or underground
- The following describes operation of a packed-bed project submitted as a response to PNMs 2022 future resource RFI
- A granular storage medium surrounds a primary well used for the heat transfer fluid – this particular design uses air as the working fluid
- The charging process consists of heating geomaterials (basalt, quartzite) with blown hot air – air is heated using an electrical resistance heater powered by the grid
- Discharging consists of moving the working fluid through the repository to move heat from the storage medium to a steam generator – this steam can then be used to power an existing turbine generator unit for electrical power production

Considerations:

- Thermal energy storage has been implemented with concentrated solar power projects at a utility scale, though other large-scale grid storage applications have not been proven
- ITC eligible
- Storage capacity is limited by the heat capacity of the storage medium
- Development and construction timeframe not entirely clear given technology deployment/readiness level, but estimated to be greater than 5 years
- Thermal storage process can be implemented at existing generation sites
- Siemens has provided a capital cost estimate of $809/kW for the thermal storage component of a 104 MW CSP plant with 10 hours of storage (2022 $)*







* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: www.csolpower.com; Clifford Ho and Walter Gerstle "Terrestrial Heat Repository For Months of Storage (Therms): A Novel Radial Thermocline System" (https://www.csolpower.com/wp-content/uploads/2021/07/ES2021_THERMS_Ho_v8.pdf)

Sources: www.csolpower.com, https://www.csolpower.com/wp-content/uploads/2021/07/ES2021_THERMS_Ho_v8.pdf

GREEN HYDROGEN

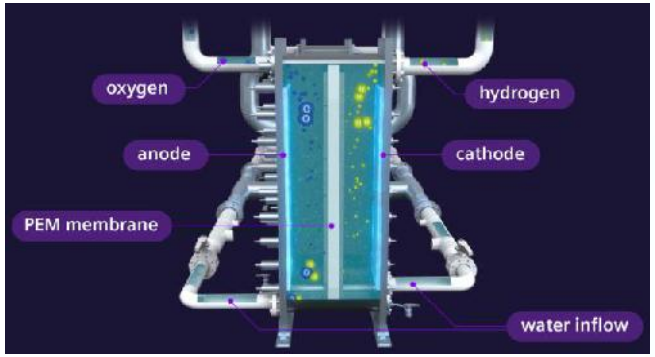
Operation:

- Green hydrogen is produced using power from renewable resources (as opposed to blue or gray hydrogen, which is created using power from fossil-fuels)
- To make hydrogen, an electrolysis process is used to split water molecules into their hydrogen and oxygen components – the following describes a process that utilizes a Polymer Electrolyte Membrane Electrolyzer
  - Each electrolyzer has two electrodes – the cathode is negatively charged, and provides electrons, while the anode is positively charged, and extracts electrons
  - The electrodes are immersed in water, which must contain salts and minerals (and thus positively and negatively charged ions) to conduct electricity
  - The negatively-charged electron-producing cathode attracts ions with a positive charge, while the positively-charged electron-releasing anode attracts ions with a negative charge
  - Water reacts at the anode to form oxygen and positively charged hydrogen ions, which flow across the PEM membrane to the cathode
  - At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas
    - The hydrogen is captured and either stored or combusted in a turbine generator
- Green hydrogen is a form of energy storage – renewable power is stored as hydrogen, and later converted back to electricity

Considerations:

- ITC/PTC available for hydrogen and renewable production (potential for stacking of credits)
- Uncertain feasibility of 100% hydrogen combustion by 2040 – technology readiness, safety issues, transportation and storage of hydrogen
- Potential for green H2 production and use in another non-power application
- Low RTE of a green hydrogen to power system, ~30%
- While PEM electrolyzers are preferable, they are expensive and use precious metals
- Siemens 2025 capital cost estimate of $1,100/kW for electrolysis equipment, and $337/kW for CT conversion (2022 $)*





Source: Siemens

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: Green Power "*Hydrogen Production by Electrolysis";* Energy.gov *"Hydrogen Production: Electrolysis"*; Encyclopedia Britannica "Electrolysis"

CARBON CAPTURE TECHNOLOGIES

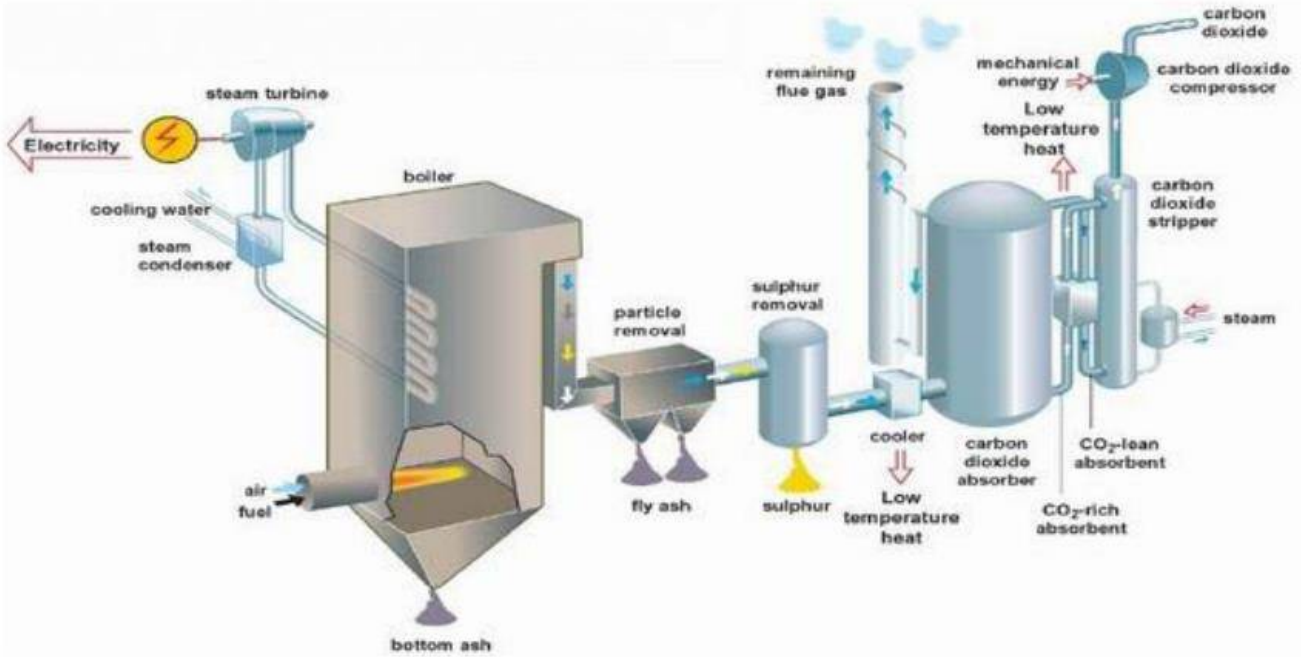
POST COMBUSTION CARBON-CAPTURE FROM FLUE GAS USING CHEMICAL ABSORPTION

Operation:

- Exhaust gasses from combustion are put into contact with a liquid amine solution, which binds with and separates the CO2
- The CO2 is then stripped out of the liquid amine solvent using steam
- The concentrated CO2 is compressed for transport and/or storage

Considerations:

- Can be utilized with existing infrastructure
- Transportation and/or storage costs for CO2 must be considered
- Carbon capture credit/ITC/PTC eligible
- Due the concentration of carbon stream in flue gas, this method is less energy intensive and cheaper than direct air capture
- Designed to capture 85-95% of CO2 produced; may not be able to capture 100% of CO2 without additional cost for CO2 absorption reactor (~10% cost increase)
- Does not reduce SOx or NOx emissions – flue gas must be treated prior to chemical absorption (though these criteria pollutant emissions would still be non-zero)
- Capital cost of natural gas combined cycle with >99% CCS ~$2,500-3,200/kW (E3 analysis; 2030 cost in 2022 $, does not include IRA impacts)



Source: E3 CPUS Zero Carbon Technology Review (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/cpuc-irp-zero-carbon-technology-assessment.pdf)

Sources: E3 *CPUC IRP Zero-Carbon Technology Assessment;* National Energy Technology Laboratory *"Carbon Dioxide Capture Approaches"*

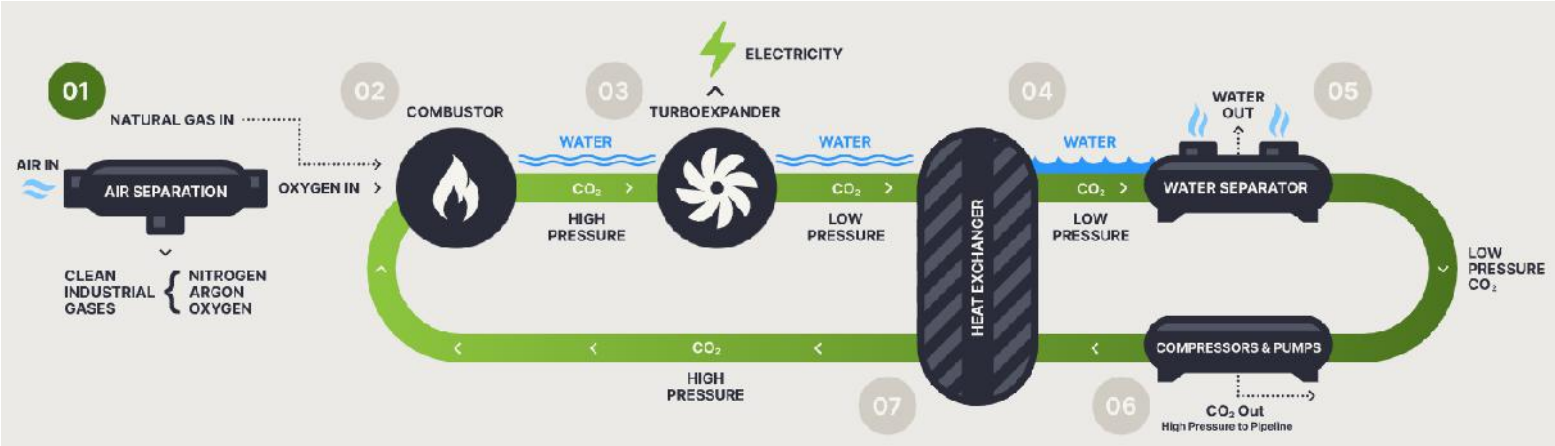
NET POWER PLANT

Operation:

- Allam power cycle uses supercritical CO2 to produce power, instead of steam (it has no emissions)
- CO2 remains in closed-loop system and never enters atmosphere, though carbon byproduct is generated
- Natural gas is combusted with oxygen (primary oxidant) and recuperated CO2
- Resulting working fluid consists of high-pressure CO2 and water; this is then expanded through a turbine for power production
- Expansion process results in low-pressure CO2 and water, which are then cooled in a heat exchanger before the water is removed, and the remaining pure CO2 stream is compressed
- At this point, excess high-pressure CO2 can be exported as a stream of pipeline-quality CO2 (could be sequestered, or sold for use in other applications), while the rest is returned to the combustor

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: NETpower, NET Power, LLC Allam Cycle Overview: https://www.youtube.com/watch?v=vFcbev1TkoU



Source: www.netpower.com

Considerations:

- Provides firm, dispatchable capacity and energy
- Uses proprietary Allam-Fetvedt process that recycles CO2 as a working fluid and captures excess as pipeline-quality CO2
- No NOx, SOx, VOC or particulate emissions
- Water-neutral; eliminates water consumption
- Proven at small scale (25 MW), but commercial viability at utility scale remains unproven; 280 MW Coyote Clean Power plant utilizing NET technology expected online in 2026
- PNM carbon emissions targets would likely necessitate requirement for 100% carbon capture and sequestration
- Siemens estimates capital cost of $2,649/kW in 2025 (2022 $, includes IRA assumptions)*

DISTRIBUTED ENERGY RESOURCES, ENERGY EFFICIENCY, AND DEMAND RESPONSE

PNM Talk to us. PNM.com

BEHIND-THE-METER SOLAR AND STORAGE

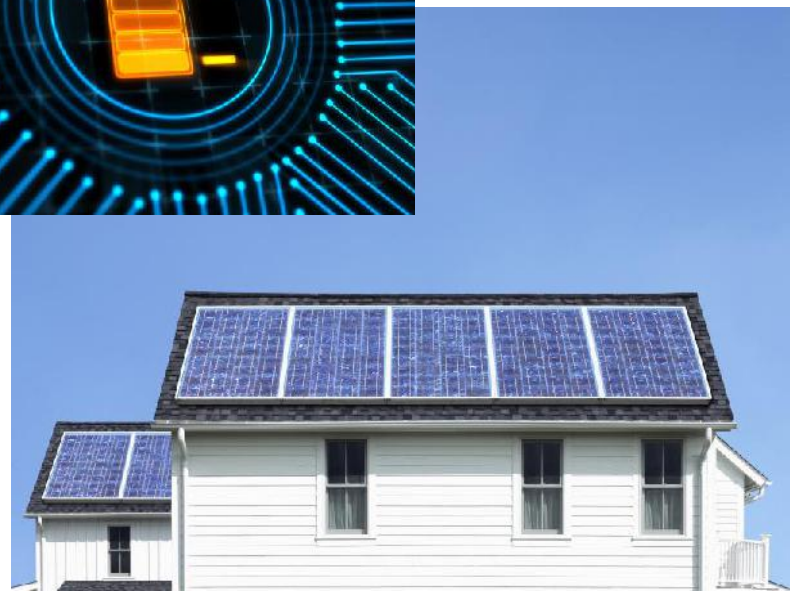
Operation:

- Solar/storage sited at customer location, connected to the distribution system
- BTM resources are on the customer side of the meter; PNM sees load net of BTM resource production (or load, in the case of storage)
- Residential solar is generally fixed-tilt, installed on rooftops
- Residential storage systems are generally lithium-ion or lead-acid batteries

Considerations:

- Increasing adoption of BTM PV can be expected given tax incentives, net metering, and general customer trends towards green energy
- Customer usage patterns and may shift as we implement time-of-use rates and AMI; customers may begin to install BTM storage at their homes and businesses
- Widespread adoption of BTM solar, storage, and EVs combined with AMI could enable aggregated customer-sited resources to become a system resource when needed (Virtual Power Plants)
- In current framework, distributed energy resources are load modifiers
- Eventually DERs will be evaluated independent of load in the resource adequacy and capacity expansion/production cost modeling framework
- These resources have their own associated risk profile, and will impact the system-level risk





Source: Microsoft stock images

ENERGY EFFICIENCY

Operation:

- Residential and commercial customers reduce energy usage by implementing efficiency measures
- Residential examples include more efficient household appliances, replacement of incandescent lighting with LEDs, better insulation and weatherization measures
- Commercial and industrial examples include high-performance buildings and efficient design, retrofits, installation of high-efficiency equipment

Considerations:

- Available potential less than technical potential
- Estimates of potential for modeling involve rigorous studies
- Incremental efficiency incentives become increasingly costly; savings from "low-hanging fruit" captured early on
- Energy efficiency modeled as load modifier
- Energy efficiency generally reduces energy needs with little impact on capacity needs



Sources: PNMenergyefficiency.com; energystar.gov; Microsoft stock images

Source: PNM Energy Efficiency

DEMAND RESPONSE

Operation:

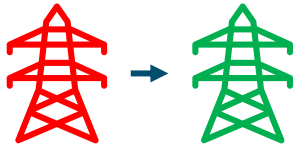
- Energy users participate in a program that provides compensation for reduced consumption when the grid is particularly stressed – such as peak summer demand periods



- During periods of high demand, users are asked to reduce energy consumption



- Demand reductions effectively act like increased generation, helping to reduce stress on the system



PNM Power Saver:

- For residential customers
- $25/year incentive to participate
- Air conditioners and heat pumps put into activation during hot summer days when electric demand is particularly high
- Home temperatures generally rise a few degrees

PNM Peak Saver:

- For commercial and industrial customers
- Annual incentive based on amount of electricity managed during participation in program
- Response called upon by system operators when needed during peak hours
- Performance measured and verified

Considerations:

- Reductions in demand – particularly during peak periods – have outsized impact on system costs as they can reduce the amount of capacity needed on the system
- As the system decarbonizes, shifting peak demands will help to enable a smoother transition
- Demand response modeled as a system resource
- Has little impact on energy needs
- AMI expected to enhance efficacy of demand response
- Customers will have varying levels of willingness to participate – achievable level of DR uncertain
- Pairs best with variable electricity rates
- New programs and incentives will need to be designed/structured

Source: https://www.pnm.com/peaksaver; https://www.pnmpowersaver.com/business/

APPENDIX: SUPPLEMENTAL INFORMATION

Talk to us.

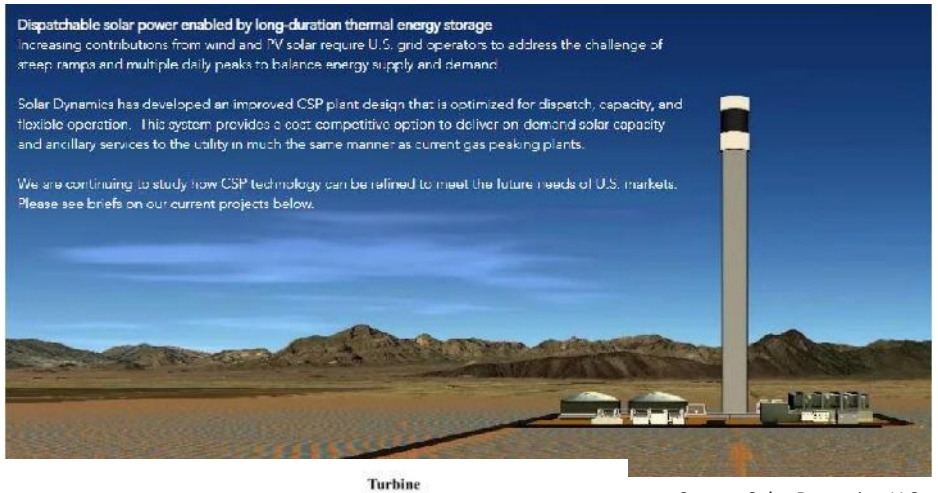
CONCENTRATED SOLAR WITH THERMAL ENERGY STORAGE

Operation:

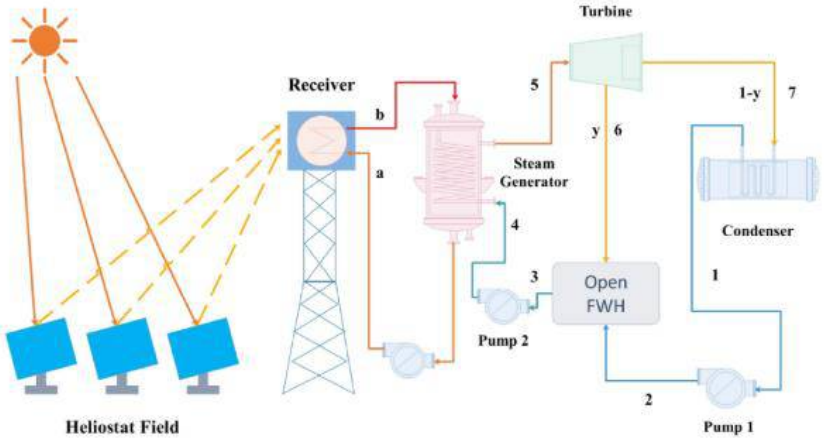
- Concentrated solar molten-salt tower with thermal energy storage is a central receiver system
- Central receiver power plants use a field of large mirrors to track the sun; these mirrors reflect energy to heat the working fluid in the tower – working fluid examples are water/steam, molten salt
- A heat exchanger transfers heat from the working fluid to water, creating steam for use in a conventional steam turbine
- The working fluid can be stored to produce power when most needed – storage size depends on the desired operating parameters

Considerations:

- 12-16 hours of energy storage possible
- No cycling limits
- Commercially available and proven at grid-scale (though not widely deployed, <10 tower projects exist)
- ITC/PTC eligible
- Longer development and construction lead-time of ~5+ years, earliest deployment late 2020's
- Siemens estimates a 2025 capital cost of $6,579/kW for a 10-hr system (2022 $)*



Source: Solar Dynamics, LLC



Source: https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.802

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: Energy.gov "*Concentrating Solar-Thermal Power Basics";* Energy.gov "Power-Tower System *Concentrating Solar-Thermal Power Basics"*

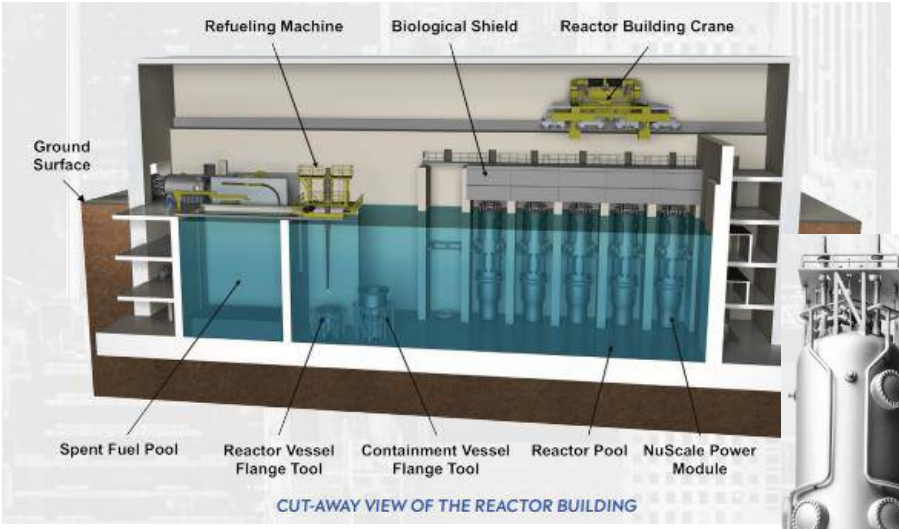
SMALL MODULAR NUCLEAR REACTOR

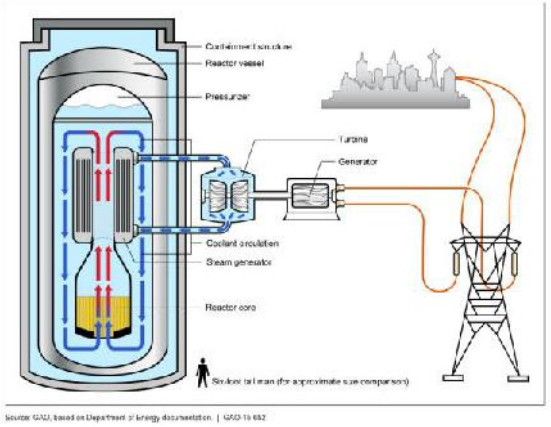
Operation:

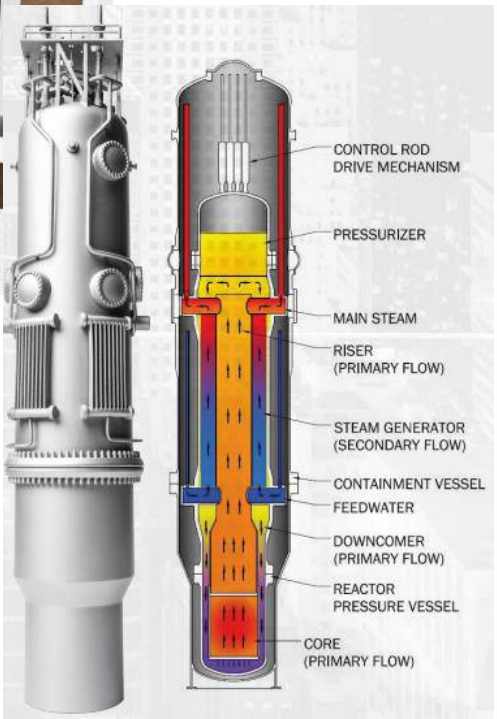
- SMRs are small (<300 MW) nuclear fission reactors that can be built in one location and shipped to operate at a separate site
- Nuclear fission is the process by which a neutron splits a uranium atom, generating additional neutrons that in turn split other uranium atoms
- Fission produces heat, which is used to make steam for use in a steam turbine generator
- SMRs employ passive safety features, which is expected to improve safety performance and require less staffing relative to conventional nuclear

Considerations:

- Carbon-free dispatchable power
- Relatively small physical footprint, modular
- Reduced fuel requirements relative to conventional nuclear
- Small reactors may produce more waste than traditional light water reactors, particularly those cooled by water, sodium, or molten salt (Stanford study published May 31, 2022)
- Could be paired with renewables to firm variations in renewable output; or provide carbon-free charging energy to batteries
- Nuclear PTC
- Most designs remain in various stages of development; not yet deployed at utility scale
- 2025 capital cost of $9,944/kW (Siemens estimate for single module Small Modular Reactor, 2022 $)*







Source: NuScale Power, LLC

* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: EIA "*Nuclear Explained*"; *NuScale*

Talk to us.

GRAVITY ENERGY STORAGE

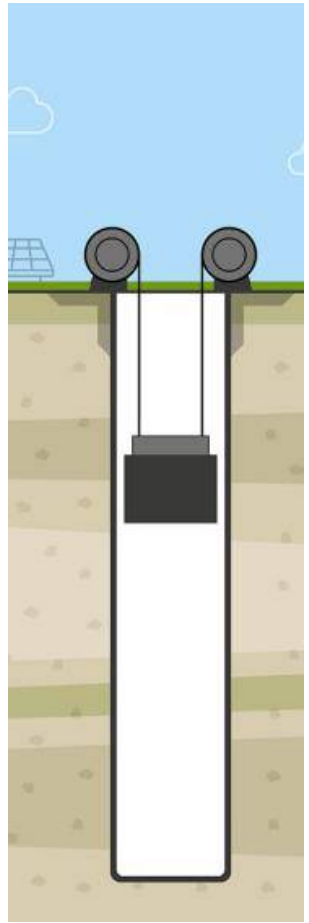
Operation:

- Utilizes gravity to generate electricity; potential energy is stored in the elevation gain of the raised mass
    - Pumped hydro storage is a form of gravitational energy storage
- There are several forms of gravitational storage, but all employ the use of electricity to lift a large object when charging
    - Electrical energy can be used to power a crane to lift and stack large bricks or composite blocks
    - Another form utilizes an electric winch to lift a weight up through an underground shaft
- When discharging, the mass is lowered using a controlled gravitational force, releasing kinetic energy which is converted to electricity through a generator

Considerations:

- 2-18 hours of duration
- Efficiency >80%
- ITC eligible
- Lots of moving parts – charging and generating equipment require maintenance
- Can require naturally occurring elevation differential or have specific siting needs
- The crane and block approach has been deployed at grid-scale in Europe, Australia, and China
- Siemens estimates a 2025 capital cost of $5,535/kW for a 100-200 MW, 12 to 16-hr system (Energy Vault (tower construction) or similar, 2022 $)*





* Siemens cost estimates reported in 2021 $, assumes 8.0% inflation in 2022

Sources: Gravitricity, Energy Vault

Sources: https://gravitricity.com/technology/, Energy Vault

2023 IRP: MODELING AND SCENARIO ANALYSIS FRAMEWORK, PROCESS TIMELINE, AND SCENARIO RUN REQUESTS

MAY 4, 2023



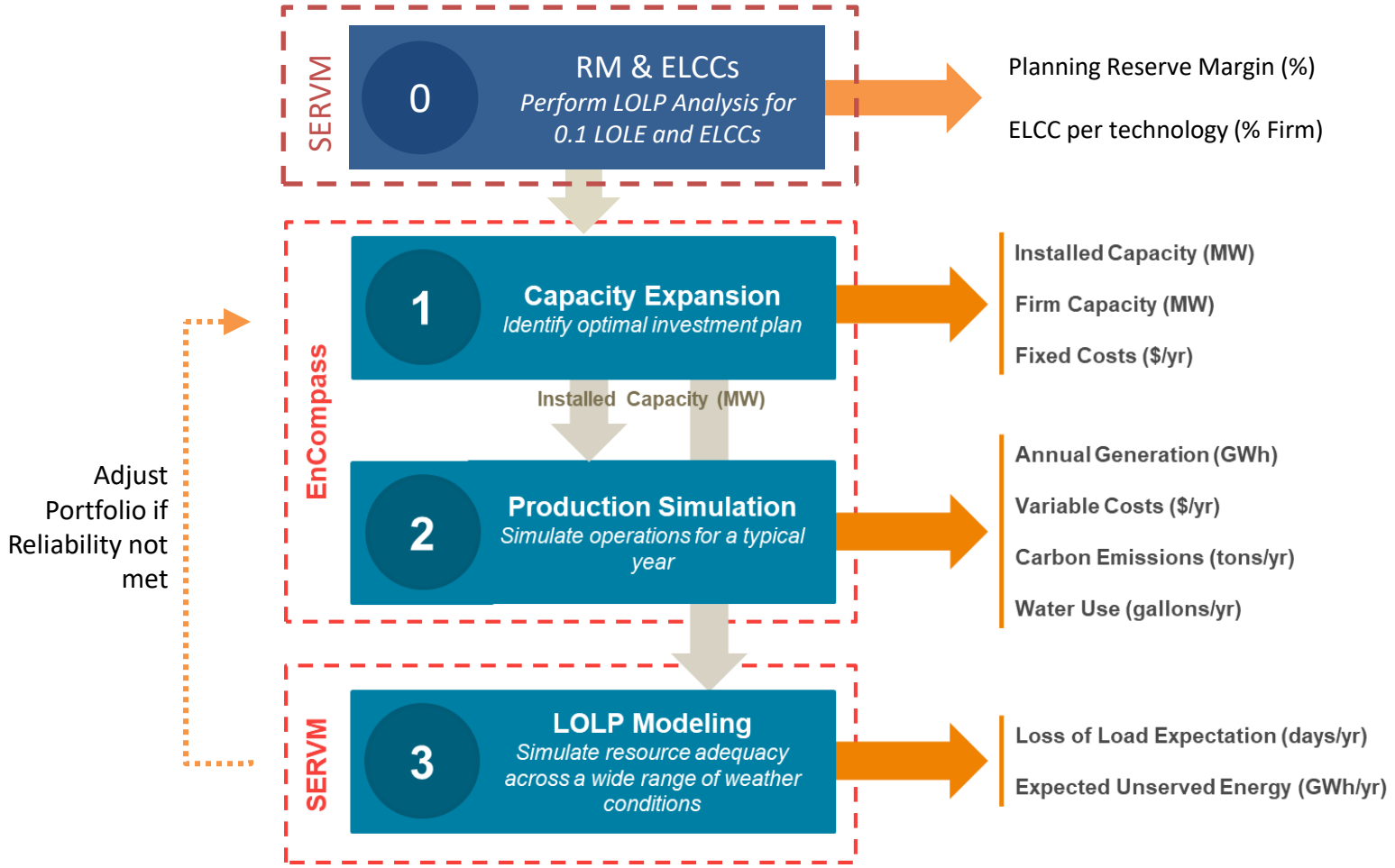
AGENDA

- **Reliability modeling and connection to capacity expansion and production cost modeling**
- **Transmission in IRP analysis**
- **IRP modeling process timeline and key dates**
- **Scenario analysis framework**
    - Terminology
    - Key elements within the 2023 IRP analysis
    - PNM scenarios for Phase 1 Modeling
- **Modeling run requests**
- **Appendix 1: PNM modeling approach and scenario detail**
- **Appendix 2: Futures and sensitivities detail**
- **Appendix 3: Additional detail on transmission modeling approaches**

RELIABILITY MODELING AND CONNECTION TO CAPACITY EXPANSION/PRODUCTION COST MODELING

Talk to us.

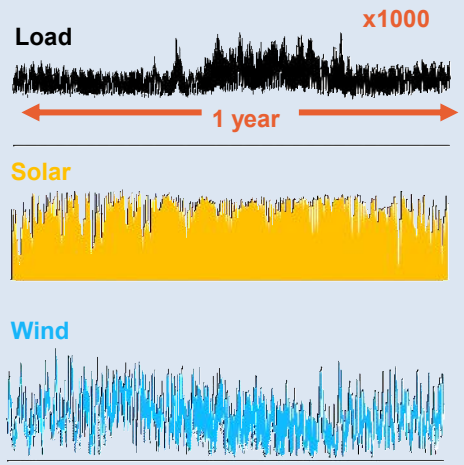
MODELING PROCESS



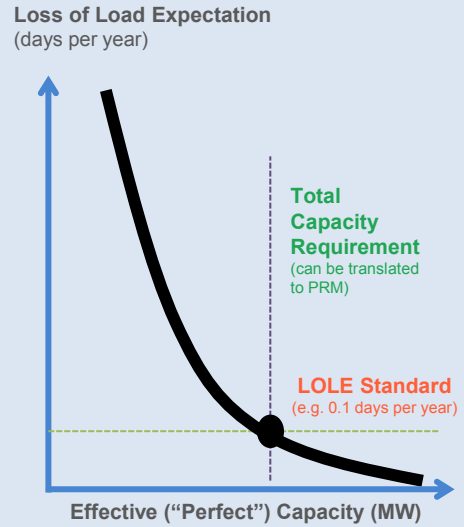
Talk to us.

BEST PRACTICES IN RESOURCE ADEQUACY ANALYSIS

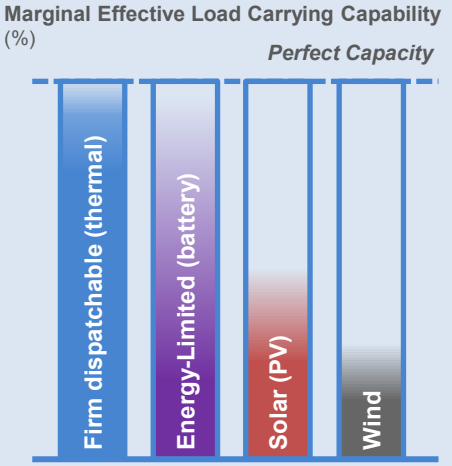
Loss of Load Probability modeling evaluates resource adequacy across all hours of the year



Amount of perfect capacity needed to achieve the desired level of reliability is identified



Effective Load Carrying Capability is calculated based on resource contributions to reliability



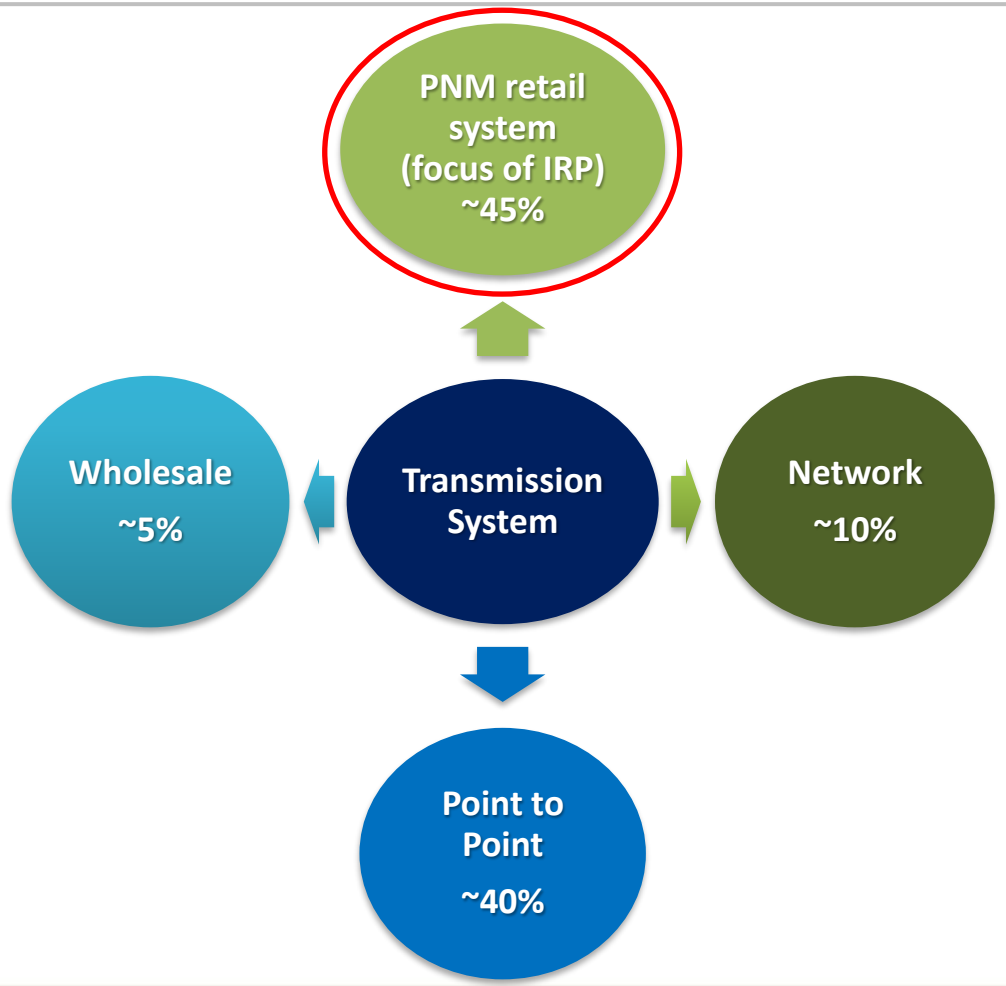
Talk to us.

TRANSMISSION IN IRP ANALYSIS

Talk to us.

PNM TRANSMISSION SYSTEM USAGE

- Transmission grid serves a variety of needs, one of which is retail power
- PNM plans and constructs its system to meet *all* forecasted transmission customer needs
- Point-to-Point service (wheeling energy between locations) represents significant usage



Talk to us.

Transmission in IRPs vs. Transmission Planning

Transmission Analysis in IRPs

+ Transmission analysis in IRPs are typically performed under a ZONAL (pipe and bubble) modeling framework
+ Purpose of the analysis is to ensure resource selection reflects the attendant needs of the transmission system and to allow evaluation of remote resources coupled with transmission expansion as an option – not to directly inform transmission investment decisions

Transmission Planning Studies

+ More detailed NODAL analysis is typically conducted in utilities' transmission planning processes, including detailed resource deliverability study, nodal production cost modeling, and power flow analysis, to support direct resource interconnection and transmission investment decisions

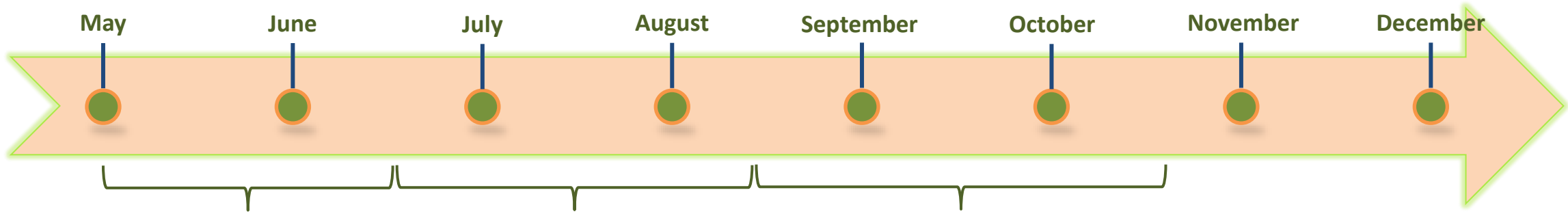


All under a zonal modeling framework, with Increasing Complexity

PNM will model cost adders and selected transmission expansion scenarios in 2023 IRP

MODELING PROCESS TIMELINE AND KEY DATES

IRP PROCESS TIMELINE



May 4 – June 15
PNM modeling

June 15 – August 17
SERVM reliability modeling (PNM MCEPs) & stakeholder EnCompass scenario modeling

August 17 – October 19
Requested SERVM runs for stakeholder scenarios

PNM

- EnCompass modeling complete by June 15 (Phases 1-3)
- PNM develops Most Cost Effective Portfolios (MCEPs)

- SERVM modeling of PNM MCEPs
- PNM runs modeling requests from Stakeholders and determines if SERVM runs are necessary

- Requested stakeholder SERVM runs
- PNM resiliency study on single MCEP

Stakeholders

- Stakeholders complete and submit modeling run requests
- PNM provides feedback regarding feasibility of modeling runs and overlap with PNM analysis

- Stakeholder EnCompass results by July 13th; stakeholders determine SERVM requested runs by August 17

Key dates:

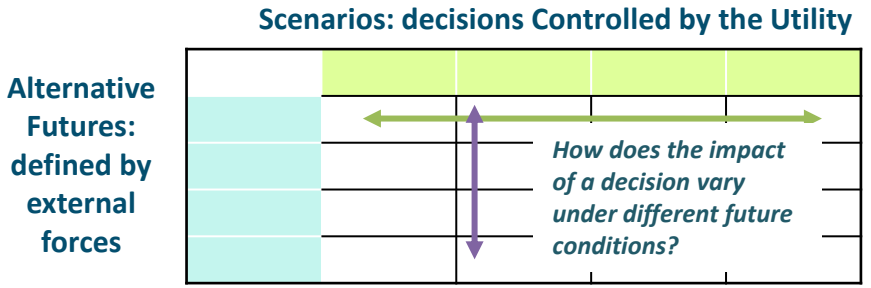
- Stakeholder modeling run requests MUST BE submitted by **June 15th**
  - Scenarios to be discussed with PNM ahead of time to avoid overlap
  - Please refer to modeling logistics document
- PNM to provide results of stakeholder modeling runs by **July 13th**
- Stakeholders review results and request selection of SERVM modeling requests by **August 17th**

2023 IRP SCENARIO ANALYSIS FRAMEWORK

Talk to us.

TERMINOLOGY AND MODELING APPROACH

- A **scenario** describes potential key decisions made by PNM
- A **future** consists of a set of forecasts or conditions that describe a future state of the world; PNM generally has no ability to influence factors that determine which future becomes reality
- A **sensitivity** describes a change in a single element of a given future; sensitivity analysis is used to understand how sensitive the results are to the changed variable



Utility decisions;
future portfolio choices made by the utility to meet objectives
e.g., resources considered, plant retirements

Scenarios

Futures

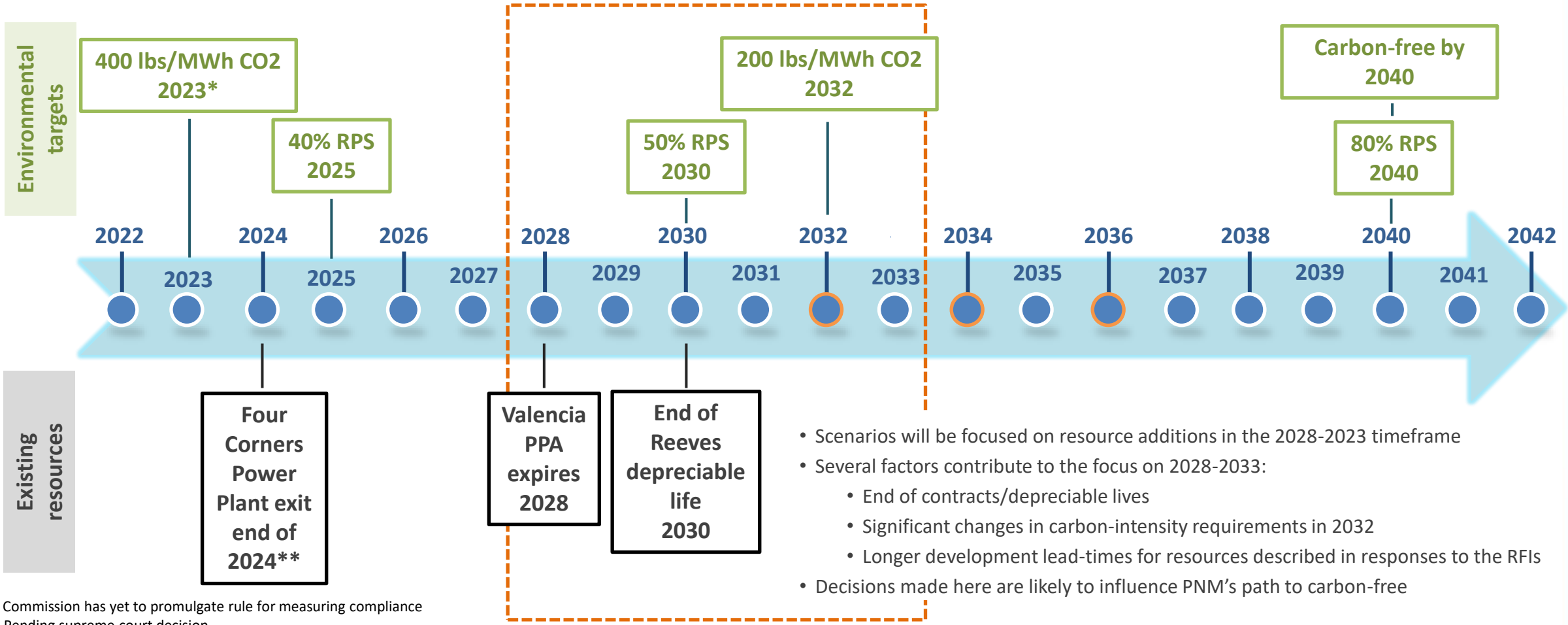
External forces; certain or uncertain variables outside of utility's control that present risks
e.g., gas price, load forecast, technology prices

Variation of selected parameter or variable within a scenario in order to understand its impact on key metrics

Sensitivities

Talk to us.

KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS

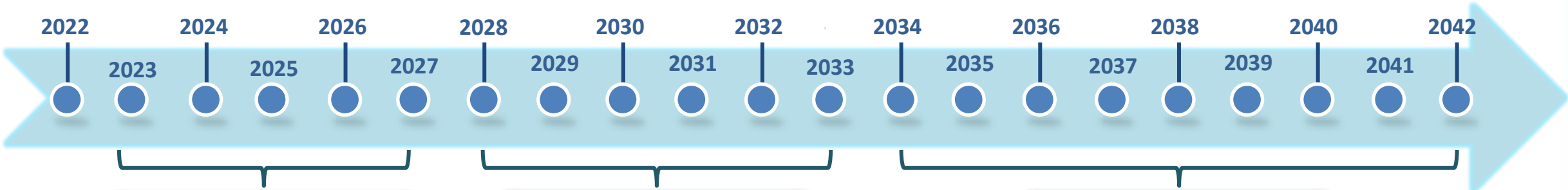


- Scenarios will be focused on resource additions in the 2028-2023 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs
- Decisions made here are likely to influence PNM's path to carbon-free

* Commission has yet to promulgate rule for measuring compliance
** Pending supreme court decision

PNM Talk to us. PNM.com

POTENTIAL RESOURCE DECISIONS IN THE 2028-2033 TIMEFRAME IMPACT LONGER-TERM SYSTEM DYNAMICS



Near-term (Action Plan Period)
2023-2027:

Low uncertainty

- The resource portfolio for this period has largely been determined through 2025; additional resources selected from near-term 2026-28 RFPs
- PNM may be required to act here to prepare for changes in the 2028-2033 period

Mid-term
2028-2033:

Focus of 2023 IRP analysis

- IRP will evaluate best mix of known resource alternatives pivotal for enabling a carbon-free system by 2040
- Carbon intensity requirement of 200 lbs/MWh in 2032 is expected to be highly impactful
- Use of the scenario screening approach

Long-term
2034-2042:

High uncertainty

- Core scenarios outline additions in the 2028-2033 timeframe, which will impact PNM's portfolio in the later years of the study period

SCENARIOS FOR PHASE 1 MODELING

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



Base + carbon capture

NM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



MODELING RUN REQUESTS

Talk to us.

KEY DELIVERABLE FROM MODELING WORKING GROUP: MODELING RUN REQUESTS

- One of the deliverables from the modeling request sub-group will be identification of a consensus set of modeling runs for PNM to implement on behalf of all stakeholders
    - If a requested modeling run is not possible, PNM will provide a discussion of why such a run is not possible, and suggest a potential alternative to the requested run

Process for requesting a modeling run (not already conducted by PNM):

1. Create technological scenarios by grouping technologies to evaluate
2. Choose future
3. Choose one or more sensitivities to augment base future assumptions (optional)
    - If more than one sensitivity is selected, an examination must be conducted to make sure the sensitivities implied in the chosen future do not conflict with additional sensitivities

MODELING RUN CREATION BY STEP

Step 1: define scenario – choose technologies

- Base technologies
- Long duration storage
- Natural gas
- Transmission expansion
- Carbon capture & storage
- Early adoption H2

Step 2: Choose future under which to evaluate scenario

- Current Trends & Policy
- High Economic Growth
- Low Economic Growth
- National carbon policy

Step 3: Choose one or more sensitivities to augment base future assumptions (optional)

Load
- High load
- Strong ED growth
- Very strong ED growth
- Extreme weather
- Low load
- TOU pricing

Technology costs
- Fast technology advancement
- Slow technology advancement
- IRA tax credits expire

Gas price
- High gas price
- Low gas price

Behind-the-meter
- High BTM PV
- Low BTM PV
- No BTM PV
- High EV adoption
- Low EV adoption
- High building electrification
- DERMS

Carbon price
- IRP rule $40 CO2 price
- IRP rule $20 CO2 price
- IRP rule $8 CO2 price
- PNM high CO2 price
- PNM mid CO2 price
- PNM low CO2 price

MODELING RUN EXAMPLE

Scenario:

Base + long-duration Storage

Technologies included for consideration in optimization:

- ☐ Scenario technologies as defined
- ☒ Include additional technologies:
  - Flow battery
  - Compressed Air Storage
- ☒ Exclude technologies:
  - Iron-air storage

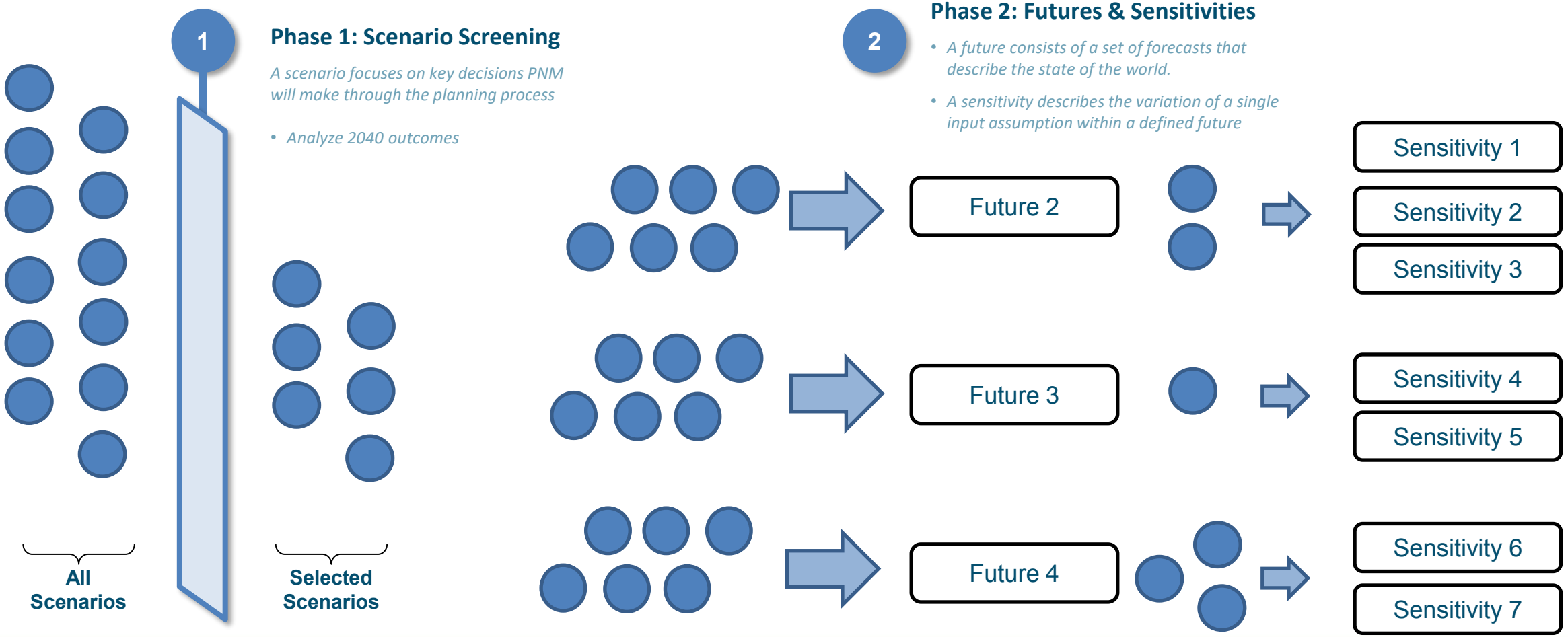
Future: Current Trends & Policy

Sensitivity 1: TOU pricing

Sensitivity 2: High carbon price

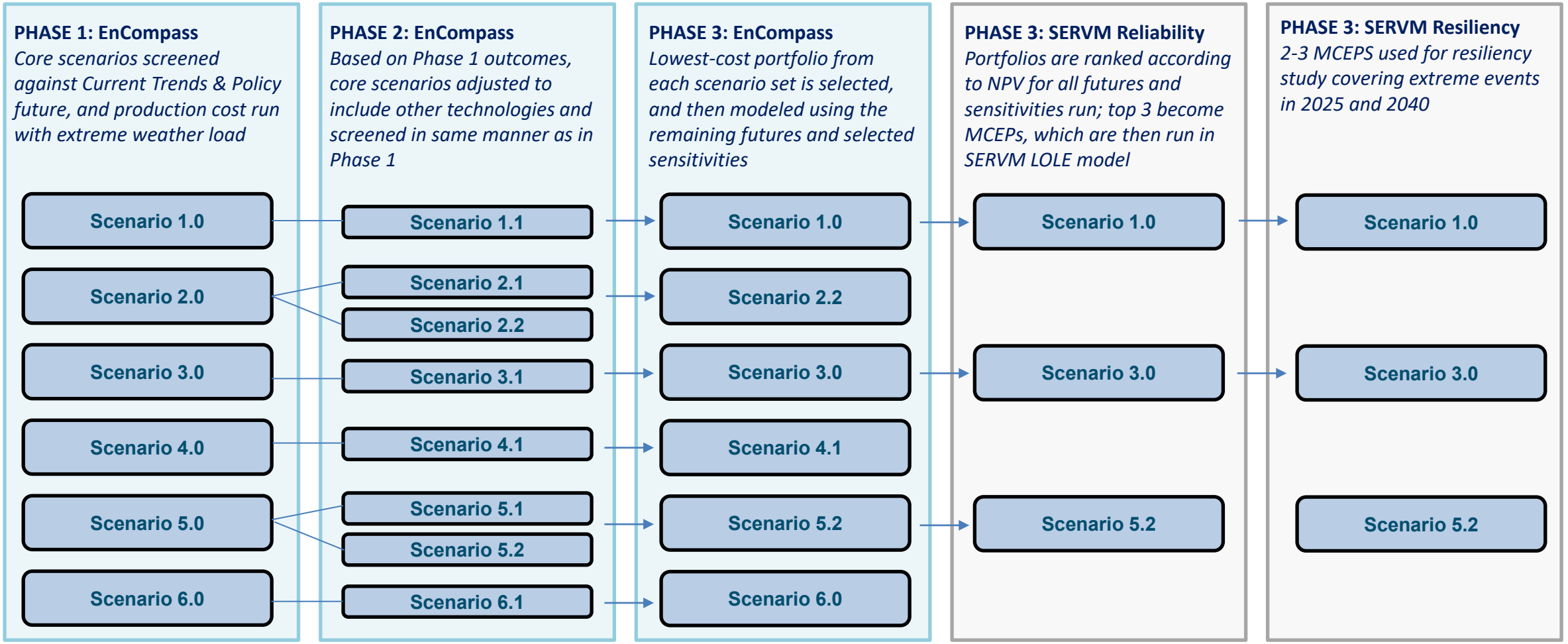
APPENDIX 1: PNM MODELING APPROACH AND SCENARIO DETAIL

SCENARIO SCREENING ILLUSTRATIVE EXAMPLE: HIGH LEVEL



Talk to us.

PNM MODELING PROCESS (ILLUSTRATIVE)



Talk to us.

SUPPLY RESILIENCE VS. RESOURCE ADEQUACY

- Traditional probabilistic analysis framework for resource adequacy is not suitable for resilience analysis
  - ***The probabilities and outcomes of potential resilience events are not well known***
- A deterministic, risk management framework based on worse case study scenarios is better suited to address resilience planning questions
  - ***Case studies allow utilities to understand the impact of potential extreme events and explore mitigation measures when making planning decisions***

Resource Adequacy	Supply Resilience
Issues that can be captured in LOLP modeling	**Issues that require a deterministic case study framework**
Potential load/renewable events based on historical conditions	Extreme load/renewable events; specific ***worse case scenarios***
Randomly simulated outages	***Correlated outages*** due to ***external or common mode events*** beyond electricity (e.g. gas fuel supply during a polar vortex, natural disasters, etc.)
The frequency, magnitude, and duration of expected loss of load events	The ***acceptability of and response to the loss of load events*** modeled

PNM Talk to us. PNM.com

PHASE 1 BASE TECHNOLOGIES SCENARIO

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



- Modeling allows for additions of generic resources in the base case and across all scenarios:
  - Solar (beginning in 2026)
  - Wind (beginning in 2033 – to compare against the Base + Wind Exp.)
  - Battery storage – 4-hr, with the option to convert to 8-hour (beginning in 2026)
- Once the RFP resources for 2026 are determined, those resources will become part of the base portfolio analyzed across all scenarios
- In other scenarios, additions of these resources are optimized around the addition of scenario resources

PHASE 1 BASE + LONG-DURATION STORAGE SCENARIO

Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal long-duration storage project(s) from selection of technologies
- Allow addition of long duration storage projects beginning in 2028 (earliest COD tied to RFI)
- Allow model to optimize among additions of:
    - 85% efficiency storage resource with long-duration/mid-ramp (70-hr) (i.e., PHS)
        - Shorter duration variant
    - ~40% efficiency storage resource with mid-duration/long-ramp (100-hr) (Form)

PHASE 1 BASE + NATURAL GAS SCENARIO

Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal natural gas project(s) from selection of technologies
- Allow addition of natural gas-fired projects beginning in 2026-2033 timeframe
- Allow model to optimize among additions of:
  - Generic gas project in any location
    - La Luz project (LM6000) – option to force addition if indicated by RFP analysis
    - Pinion project (LM6000) – option to force addition if indicated by RFP analysis
  - Linear generator units
- All gas resources will be converted to burn Hydrogen at the end of 2039 (assumes hydrogen economy)

PHASE 1 BASE + WIND EXPANSION SCENARIO

Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal level of new transmission with access to generic wind resource in eastern New Mexico
- Transmission project added in 2030-2032 timeframe
- Transmission project reflects a new "pipe", with access to new "bubble" containing wind resources
- Allow for optimization regarding:
    - When to add the transmission line
    - The amount of new wind to add

PHASE 1 BASE + CARBON CAPTURE SCENARIO

Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal carbon-free dispatchable project(s) from selection of technologies
- Allow for addition of carbon capture and storage technologies beginning in 2028
- Allow model to optimize among additions of:
  - Existing CCGT fitted with Carbon Capture and Storage (CCS) technology
  - New or existing CT with CCS
  - Net Power Plant with CO2 transport and storage

PHASE 1 BASE + HYDROGEN SCENARIO

Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



- Modeling allows for addition of base case resources (generic solar, wind, and storage) plus optimal hydrogen-fueled project(s) from selection of technologies
- A hydrogen facility will include electrolysis, on-site storage, and CT for combustion
- Hydrogen tax credits applied
- Allow for addition of hydrogen facilities starting in 2028
- Allow model to optimize among additions of:
    - Small project (250 MW)
        - Greenfield and brownfield options
    - Large project (500 MW)
        - Greenfield and brownfield options

SCENARIOS FOR PHASE 2 MODELING

Base technologies only

Variations:

1. FCPP exit end of 2027
2. FCPP exit by July 2031



Base + long-duration Storage

Variations:

1. Original +8-hr PHS
2. Original +CAES, Flow battery
3. Original with timing adjustments
4. Original with inventory adjustments for chosen technologies
5. Other variations dependent on Phase 1 results



Base + natural gas

Variations:

1. Original + Iron-air storage
2. Original with FCPP exit in 2027
3. Original with FCPP exit in 2031
4. Original with Reeves retiring in 2030, repowered with LM6000s
5. Other variations dependent on Phase 1 results



Base + wind expansion

Variations:

1. Sensitivities regarding size of new wind resource available
2. Original pipe & bubble, add long-duration storage to bubble
3. North-South transmission line
4. Other variations dependent on Phase 1 results



Base + carbon capture

Variations:

1. Variants dependent on Phase 1 results



Base + H2/early gas conversion

Variations:

1. Variants dependent on Phase 1 results



APPENDIX 2: FUTURES, SENSITIVITIES, AND TECHNOLOGIES AVAILABLE FOR MODELING

2023 IRP CORE FUTURES

Key assumption	Current Trends & Policy	High Economic Growth	Low Economic Growth	National Carbon Policy (Carbon-free by 2035)
Load forecast	Mid	High	Low	High
BTM PV forecast	Mid	High	Low	High
EV adoption forecast	Mid	High	Low	High
Building Electrification Forecast	Mid	Mid	Mid	High
Economic development	Limited	Accelerated	Limited	Stable
Gas price forecast	Mid	Mid	Low	High
Carbon price forecast	Mid	Mid	Mid	High
Technology cost forecast	Mid	Mid	Mid	Low

2023 IRP SENSITIVITIES

Gridworks Compiled Presentations

	Sensitivity	Load forecast	Economic Development	BTM PV forecast	EV adoption forecast	Building electrification	Gas price forecast	CO2 price forecast	Technology costs	IRA tax credits & incentives
Load	High load	**High**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Strong ED growth	Mid	**Stable**	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Very strong ED growth	Mid	**Accelerated**	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Extreme weather	**P90 hot/cold**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Low load	**Low**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	TOU pricing	**TOU shaping**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
BTM	High BTM PV	Mid	Limited ED	**High**	Mid	Mid	Mid	Mid	Mid	Extended
	Low BTM PV	Mid	Limited ED	**Low**	Mid	Mid	Mid	Mid	Mid	Extended
	No BTM PV	Mid	Limited ED	**Zero**	Mid	Mid	Mid	Mid	Mid	Extended
	High EV adoption	Mid	Limited ED	Mid	**High**	Mid	Mid	Mid	Mid	Extended
	Low EV adoption	Mid	Limited ED	Mid	**Low**	Mid	Mid	Mid	Mid	Extended
	High building electrification	Mid	Limited ED	Mid	Mid	**High**	Mid	Mid	Mid	Extended
	DERMS	Mid	Limited ED	**High**	**High**	Mid	Mid	Mid	Mid	Extended
Gas price	High gas price	Mid	Limited ED	Mid	Mid	Mid	**High**	Mid	Mid	Extended
	Low gas price	Mid	Limited ED	Mid	Mid	Mid	**Low**	Mid	Mid	Extended
Carbon price	IRP rule $40 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$40/ton**	Mid	Extended
	IRP rule $20 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$20/ton**	Mid	Extended
	IRP rule $8 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$8/ton**	Mid	Extended
	PNM high CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**High**	Mid	Extended
	PNM mid CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	PNM low CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**Low**	Mid	Extended
Technology costs	Fast technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	**Low**	Extended
	Slow technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	**High**	Extended
	IRA tax credits expire	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	**Expire 2032-2034**

TECHNOLOGIES BY SCENARIO

As defined:

Base technologies only



- Solar
- Wind (beginning in 2033)
- Battery storage (4-hr)
- *Additions of these technologies optimized in all scenarios*

Base + long-duration Storage



- Long-duration Pumped-hydro storage (70-hr)
- Shorter duration Pumped-hydro storage (8 to 12-hr)
- Long-duration iron-air storage (100-hr)

Base + natural gas



- Generic gas project (Combustion turbine)
- Linear generator units
- *All resources converted to burn Hydrogen in 2040*

Base + wind expansion



- New transmission project reflects a new “pipe”, with access to new “bubble” containing wind resources

Base + carbon capture



- Existing CCGT fitted with Carbon Capture and Storage (CCS) technology
- New or existing CT with CCS
- Net Power Plant with CO2 transport and storage

Base + H2/early gas conversion



- Hydrogen facility with on-site electrolysis, storage, and CT for combustion
  - Small project (250 MW), greenfield and brownfield options
  - Large project (500 MW), greenfield and brownfield options

Other technology options:

- Concentrated solar power with thermal energy storage
- Thermal energy storage (steam turbine)
- Flow battery (10-hr)
- Compressed Air storage
- Liquid air storage

- Option to add other resources to bubble in addition to/in place of wind

APPENDIX 3: ADDITIONAL DETAIL ON TRANSMISSION MODELING APPROACHES

Tradeoffs among transmission modeling approaches

Methodology	Advantages	Limitations
Cost Adders Generic transmission assumptions used to develop cost adders that are applied to resources in capacity expansion modeling	• Can easily be incorporated into any capacity expansion model	• Difficult to capture "lumpiness" of new transmission investments • Only suitable for transmission whose primary benefit is the delivery of new resources to loads
Scenario Analysis Scenarios with and without certain transmission projects are analyzed in resource planning analysis, which allows the planners to compare the benefits and costs associated with those transmission projects	• Provides an explicit quantification of the benefits of a specific project (or set of projects)	• Puts pressure on scenario design to identify the right set of options to study • Difficult to examine generic long-term transmission options when used alone
Co-optimization of Generation and Transmission (under zonal representation) Potential transmission upgrade and expansion are characterized as candidate new build options which increase transmission capability between zones with estimated costs in capacity expansion models; resource and transmission expansion are co-optimized in the modeling process	• Allows for better characterization of resource competition of transmission capacity within a zone and the "lumpiness" of new transmission investments	• Computationally complex to implement; not compatible with all capacity expansion models • Subject to knife-edge effects

MODELING INPUTS FOR 2023 IRP ANALYSIS

MAY 4, 2023



CONTENTS

Modeling working group next steps:

- IRP process timeline
- Modeling run request creation and example

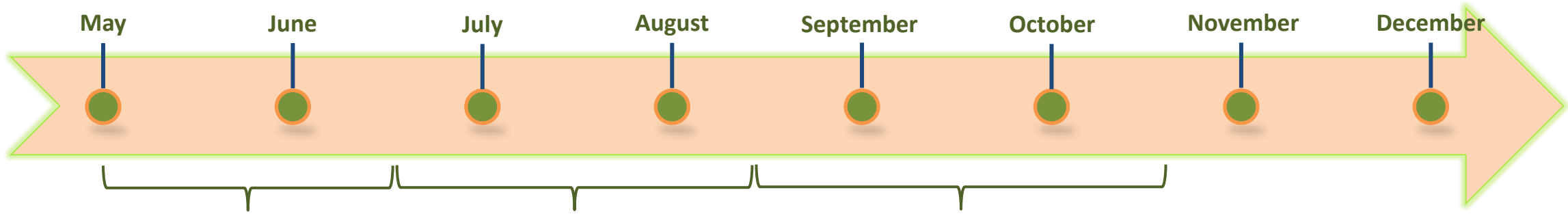
Modeling inputs:

- High-level modeling framework
- Inputs, requirements, and outputs for capacity expansion optimization
- Inputs, requirements, and outputs for production cost modeling
- Reliability inputs and market import limits
- Load and resource inputs
- Environmental constraints
- Commodity price inputs
- Changes to inputs
- EnCompass: modeling for performance
- EnCompass: commitment levels and runtime tradeoffs
- **Appendix: additional detail on selected inputs**

MODELING WORKING GROUP NEXT STEPS

Talk to us.

IRP PROCESS TIMELINE



May 4 – June 15
PNM modeling

June 15 – August 17
SERVM reliability modeling (PNM MCEPs) & stakeholder EnCompass scenario modeling

August 17 – October 19
Requested SERVM runs for stakeholder scenarios

PNM

- EnCompass modeling complete by June 15 (Phases 1-3)
- PNM develops Most Cost Effective Portfolios (MCEPs)

- SERVM modeling of PNM MCEPs
- PNM runs modeling requests from Stakeholders and determines if SERVM runs are necessary

- Requested stakeholder SERVM runs
- PNM resiliency study on single MCEP

Stakeholders

- Stakeholders complete and submit modeling run requests
- PNM provides feedback regarding feasibility of modeling runs and overlap with PNM analysis

- Stakeholder EnCompass results by July 13th; stakeholders determine SERVM requested runs by August 17

Key dates:

- Stakeholder modeling run requests MUST BE submitted by **June 15th**
  - Scenarios to be discussed with PNM ahead of time to avoid overlap
  - Please refer to modeling logistics document
- PNM to provide results of stakeholder modeling runs by **July 13th**
- Stakeholders review results and request selection of SERVM modeling requests by **August 17th**

Talk to us.

KEY DELIVERABLE FROM MODELING WORKING GROUP: MODELING RUN REQUESTS

- One of the deliverables from the modeling request sub-group will be identification of a consensus set of modeling runs for PNM to implement on behalf of all stakeholders
    - If a requested modeling run is not possible, PNM will provide a discussion of why such a run is not possible, and suggest a potential alternative to the requested run

Process for requesting a modeling run (not already conducted by PNM):

1. Create technological scenarios by grouping technologies to evaluate
2. Choose future
3. Choose one or more sensitivities to augment base future assumptions (optional)
    - If more than one sensitivity is selected, an examination must be conducted to make sure the sensitivities implied in the chosen future do not conflict with additional sensitivities

MODELING RUN CREATION BY STEP

Step 1: define scenario – choose technologies

- Base technologies
- Long duration storage
- Natural gas
- Transmission expansion
- Carbon capture & storage
- Early adoption H2

Step 2: Choose future under which to evaluate scenario

- Current Trends & Policy
- High Economic Growth
- Low Economic Growth
- National carbon policy

Step 3: Choose one or more sensitivities to augment base future assumptions (optional)

Load
- High load
- Strong ED growth
- Very strong ED growth
- Extreme weather
- Low load
- TOU pricing

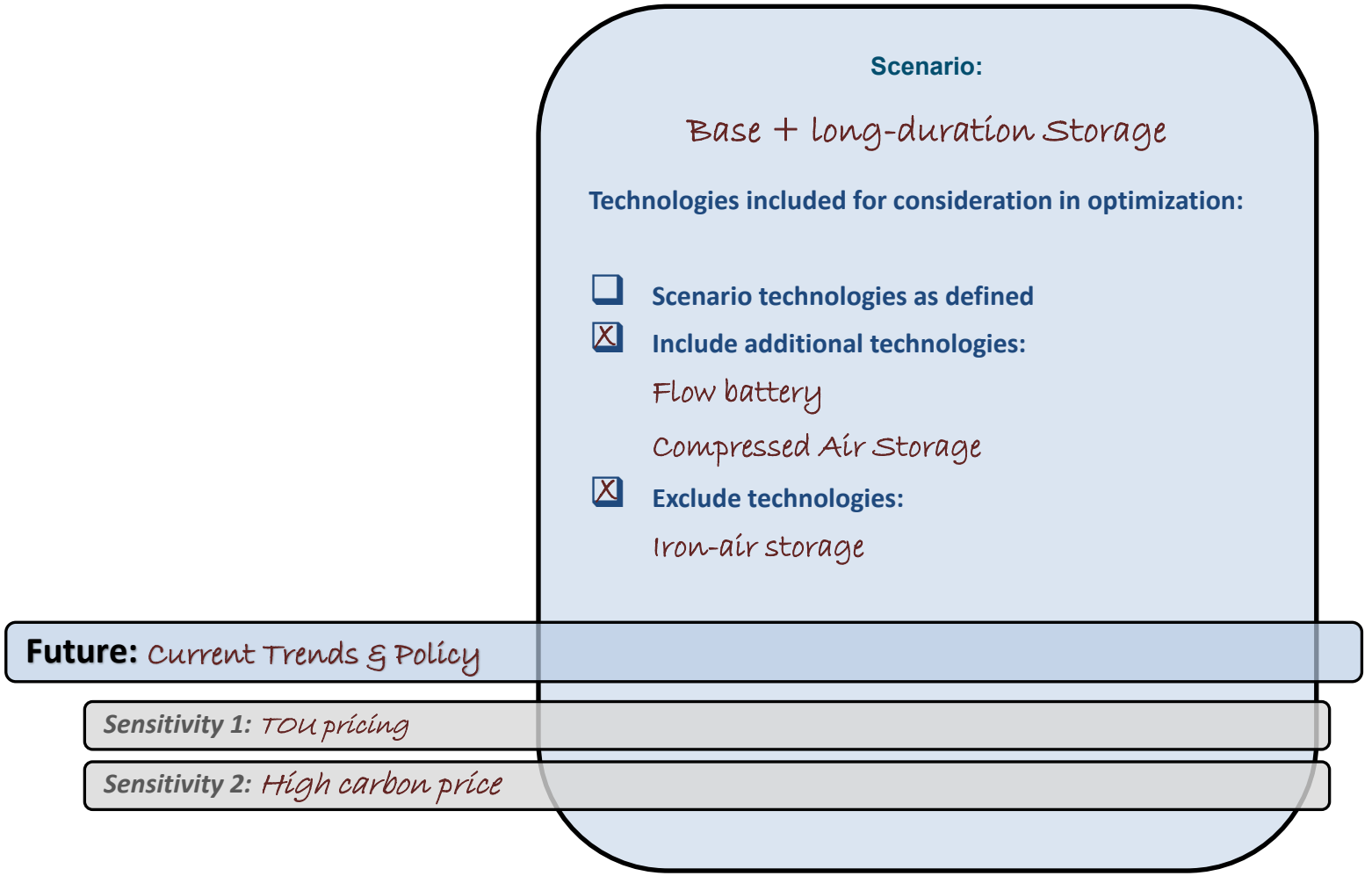
Technology costs
- Fast technology advancement
- Slow technology advancement
- IRA tax credits expire

Gas price
- High gas price
- Low gas price

Behind-the-meter
- High BTM PV
- Low BTM PV
- No BTM PV
- High EV adoption
- Low EV adoption
- High building electrification
- DERMS

Carbon price
- IRP rule $40 CO2 price
- IRP rule $20 CO2 price
- IRP rule $8 CO2 price
- PNM high CO2 price
- PNM mid CO2 price
- PNM low CO2 price

MODELING RUN EXAMPLE

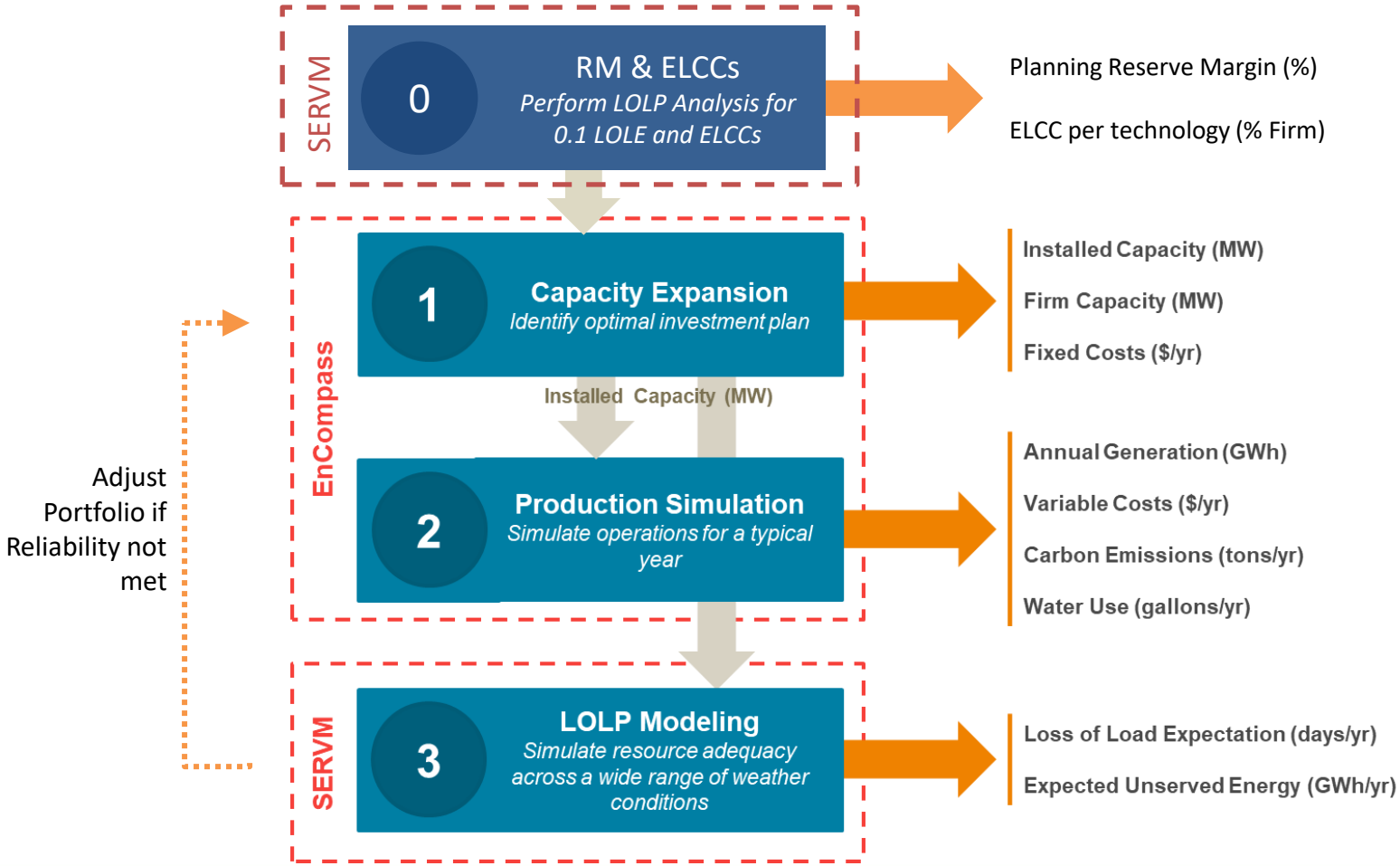


Talk to us.

MODELING INPUTS

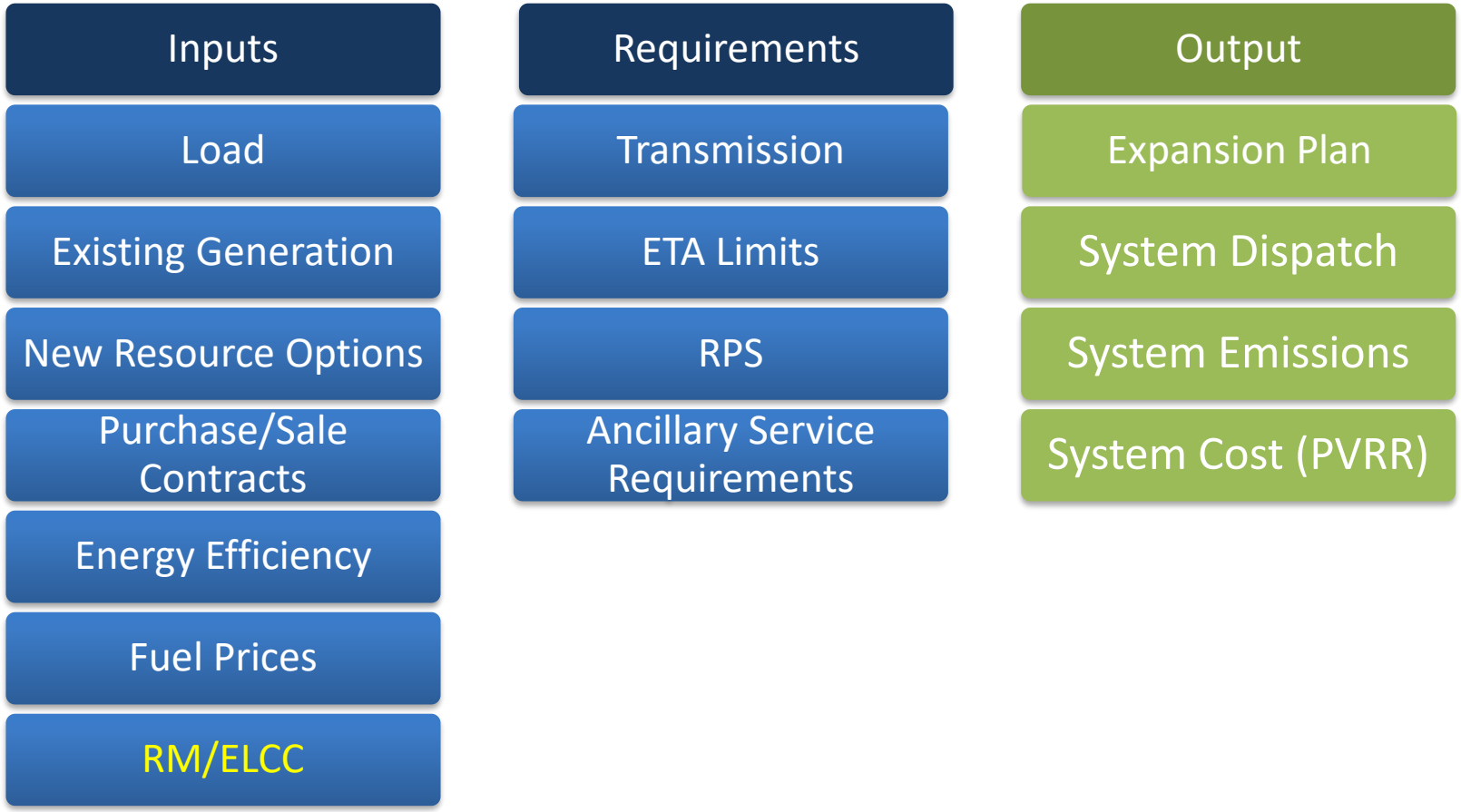
Talk to us.

MODELING FRAMEWORK



Talk to us.

PNM SYSTEM MODELING – CAPACITY EXPANSION



PNM Talk to us. PNM.com

PNM SYSTEM MODELING – PRODUCTION COST MODELING

Inputs	Requirements	Outputs
Expansion plan	Transmission	Detailed Dispatch
Load	ETA Limits	Emissions
Existing generation	RPS	System Costs (PVRR)
New resource options	Ancillary Service Requirements	
Purchase/Sale Contracts	Market Transaction Limits	
Energy Efficiency		
Fuel Prices		
Energy Market prices		

PNM Talk to us. PNM.com

RELIABILITY INPUTS AND MARKET IMPORT LIMITS

Planning Reserve Margin (PRM):

- 16% for 0.1 LOLE target

ELCCs for new and existing resources:

- Utilize 3-axis ELCC curves for wind, solar, and storage accounting for diversity benefits and resource interactions
- See Appendix for summary
- See January 17, 2023 presentation on Astrape ELCC study results

Market import limitations:

- Modeled market assistance included in resource adequacy analysis reflects wholesale transactions based on economics and transmission constraints
- Market participation is allowed in all hours except for the following constraints:
  - Limited to 200-300 MW in all hours when load is greater than 85% of the gross peak load
  - Limit to 100-150 MW for Jun-Aug hours 16-18 when load is greater than 85% of gross peak load
  - Limit to 50 MW for Jun-Aug hours 19-22 when hourly gross load is greater than 80% of the gross peak load
- See January 17, 2023 presentation on Market Imports and Summer 2022 review

LOAD AND RESOURCE INPUTS

Load forecasts:

- Reference forecast
- High economics
- Low economics
- Strong energy growth
- Weak energy growth
- High BTM PV
- Low BTM PV
- Zero incremental BTM PV
- Zero BTM PV
- High EV adoption
- Low EV adoption
- Aggressive environmental regulation
- High building electrification
- TOU pricing
- Extreme weather
- See December 15, 2022 presentation on Energy Efficiency, Load Forecast, and Pricing topics

Energy efficiency:

- Existing EE programs
- New EE bundles
- See June 22, 2022 and December 15, 2022 presentation on Energy Efficiency programs and bundles

Resources:

- Existing generation
  - Existing nuclear, coal, and gas
  - Existing wind, solar, and storage
  - 2026 RFP resources
- New generic resource options
  - Wind, solar, storage
- New RFI resource options
- See November 2, 2022 presentation on Siemens commodity price forecast and technology costs
- See February 15, 2023 presentation on Modeling Framework, Core Scenarios, and RFI selections
- See Appendix H of 2020 IRP for existing resource detail

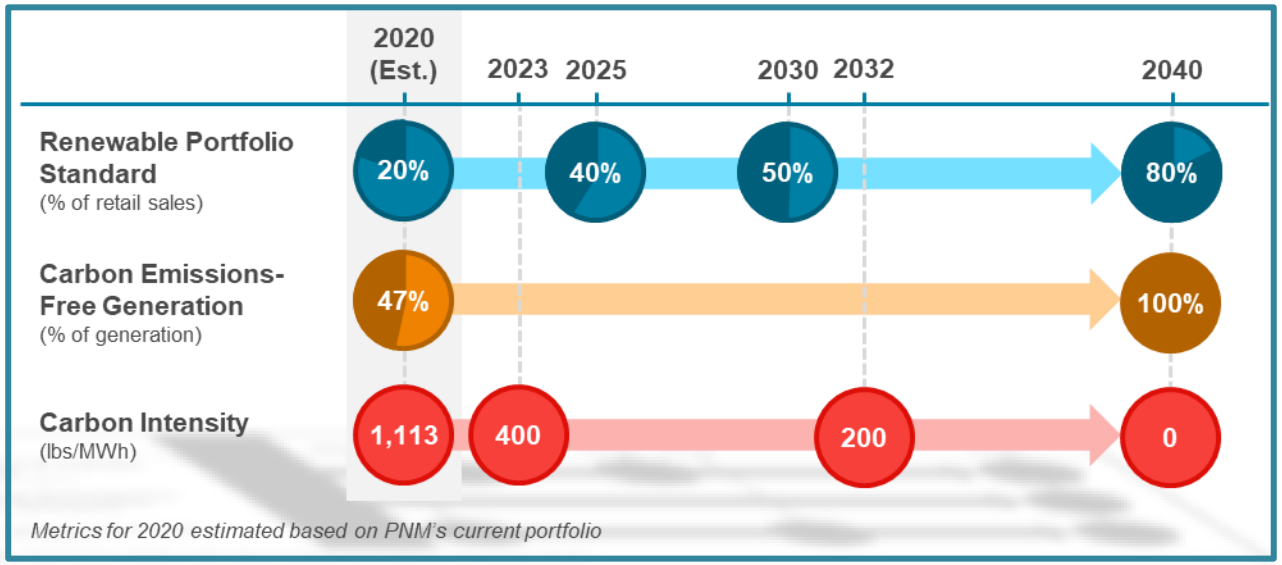
ENVIRONMENTAL PROGRAM INPUTS (CONSTRAINTS)

Energy Transition Act:

- 400 lbs CO2/MWh in 2023
- 200 lbs CO2/MWh by 2032
- 0 lbs CO2/MWh by 2040

Renewable Portfolio Standard:

- 40% of retail sales supplied by renewables in 2025
- 50% of retail sales supplied by renewables in 2030
- 80% of retail sales supplied by renewables in 2040



Talk to us.

COMMODITY PRICE INPUTS

Energy market prices:

- Developed by Horizons Energy using National Database

Fuel prices:

- Natural gas hub pricing
  - San Juan (Northern resources, ABQ resources, FCPP startup)
  - Permian basin (Southern resources)
  - See November 2, 2022 presentation on Commodity Pricing forecasts
  - See Appendix for summary
- Hydrogen pricing developed by E3
  - See appendix for summary

CO2 prices:

- PNM will utilize Siemens CO2 price forecast, with adjustments for 2028 start year
- See appendix for summary
- See November 2, 2022 presentation on Commodity Pricing forecasts

CHANGES TO INPUTS

Inputs/assumptions that can be adjusted

- Fuel prices (natural gas, hydrogen)
- Technology cost curves, capital costs
- New candidate resources costs and/or operating parameters
- Transmission cost adders
- Timing of CO2-free
- RPS timing and requirements

Inputs/assumptions with some flexibility for adjustment

- Market prices
- CO2 prices
- PV or EV assumptions embedded in reference load forecast

Static inputs/assumptions (long lead time for development)

- Reliability requirements (LOLE target, PRM)
- ELCCs
- PNM WACC
- Energy Efficiency Bundles
- New/different load forecasts
- Study period (2023-2042)

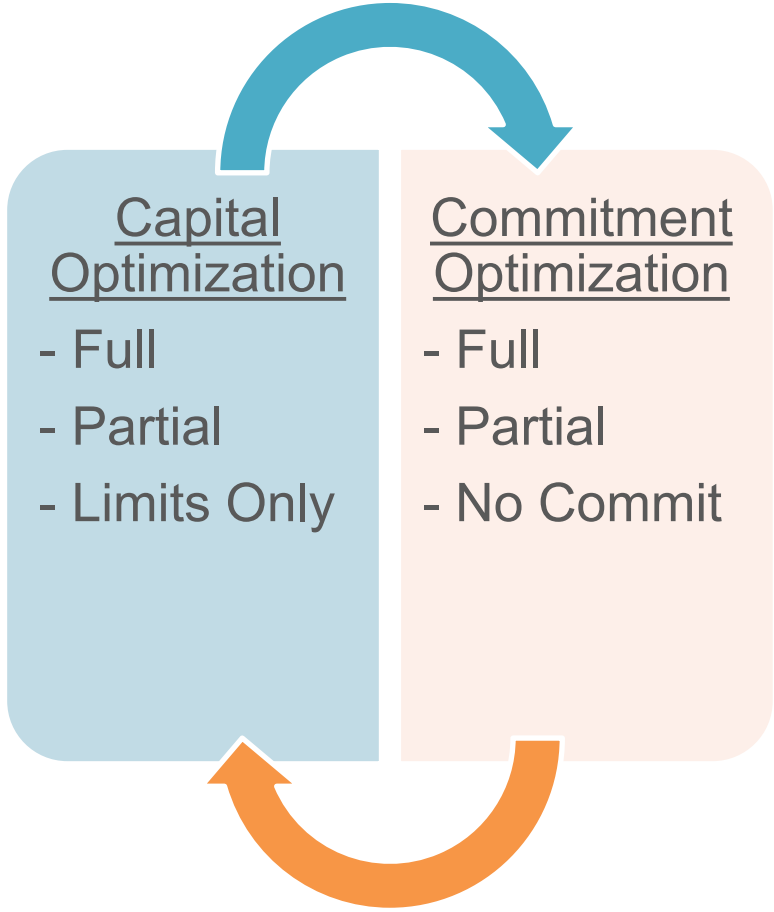
PNM Talk to us. PNM.com

ENCOMPASS MODELING FOR PERFORMANCE

Maximize commitment and dispatch detail of existing and new resources within simulations



Minimize time to perform detailed simulations to allow more time for additional scenarios/and or in-depth analysis



PNM Talk to us. PNM.com

ENCOMPASS MODELING FOR PERFORMANCE - COMMITMENT

No Commitment

Enforced
- Ramp rates
- Ancillary requirements (spin)

Ignored
- Min Capacity (non-must-run)
- Regulation (min/max range)
- Min Uptime/Downtime

Estimated
- Starts/Shutdowns

Best For:
- Scenario Capacity Expansion Planning

Partial Commitment

Enforced
- Starts/Shutdowns (fractional, i.e., 0.4 units = 1 unit @ 40%)
- Ramp rates
- Ancillary requirements (spin)
- Regulation (min/max range)
- Min Uptime/Downtime

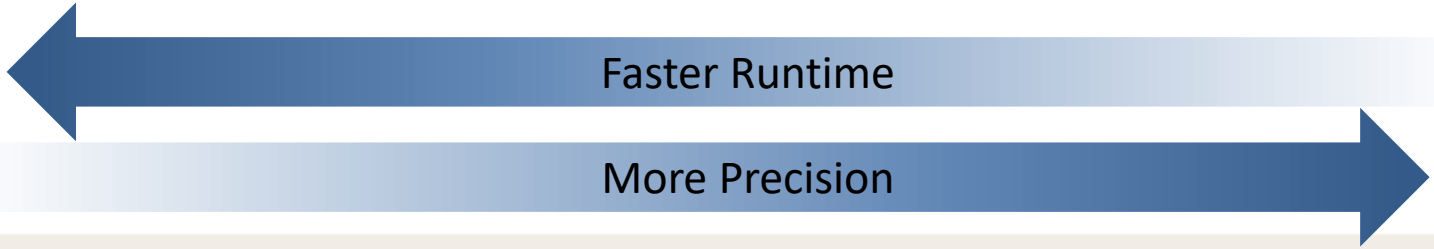
Ignored
- Min Capacity (non-must-run)

Best For:
- Scenario Production Cost Modeling (Annual/Monthly)
- Annual Emission Limits

Full Commitment

Enforced
- Starts/Shutdowns (integer)
- Ramp rates
- Ancillary requirements (spin)
- Min Capacity (non-must-run)
- Regulation (min/max range)
- Min Uptime/Downtime

Best For:
- Hourly Production Cost/Dispatch

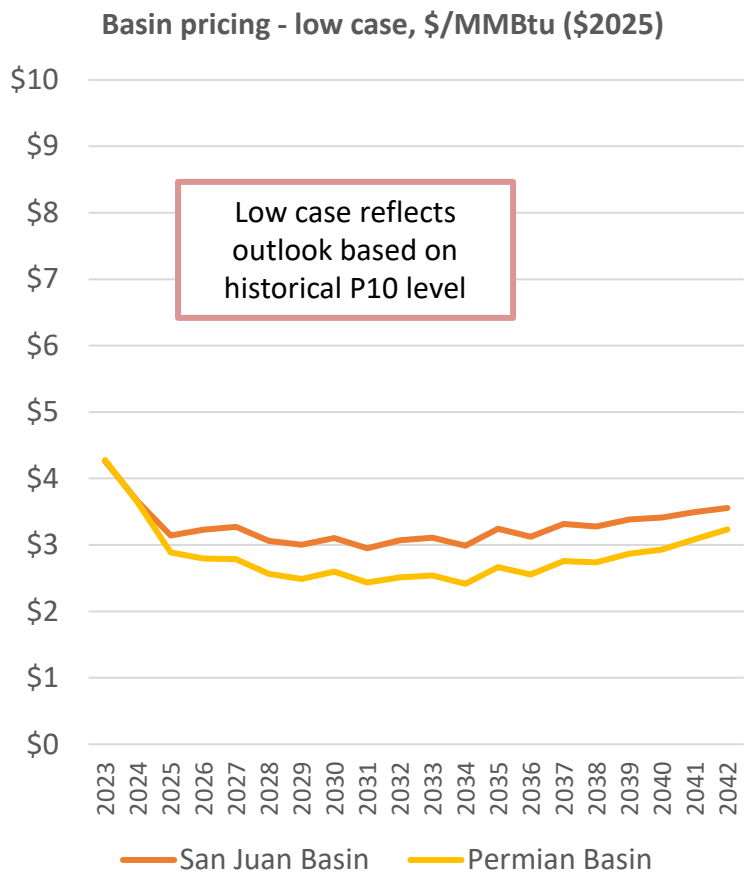


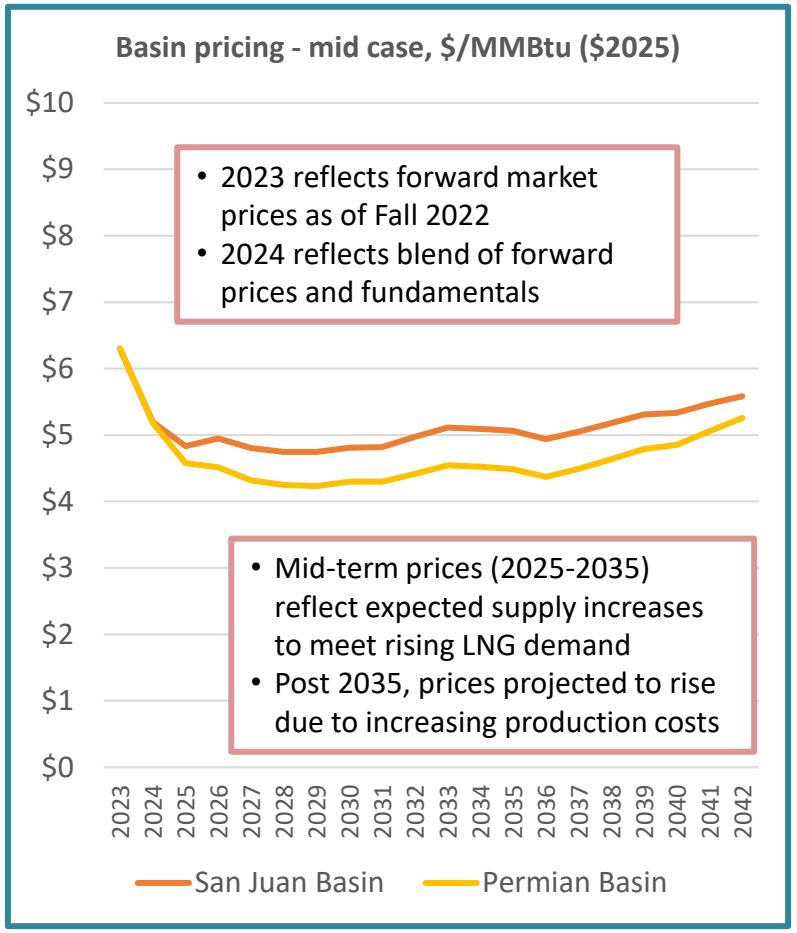
PNM Talk to us. PNM.com

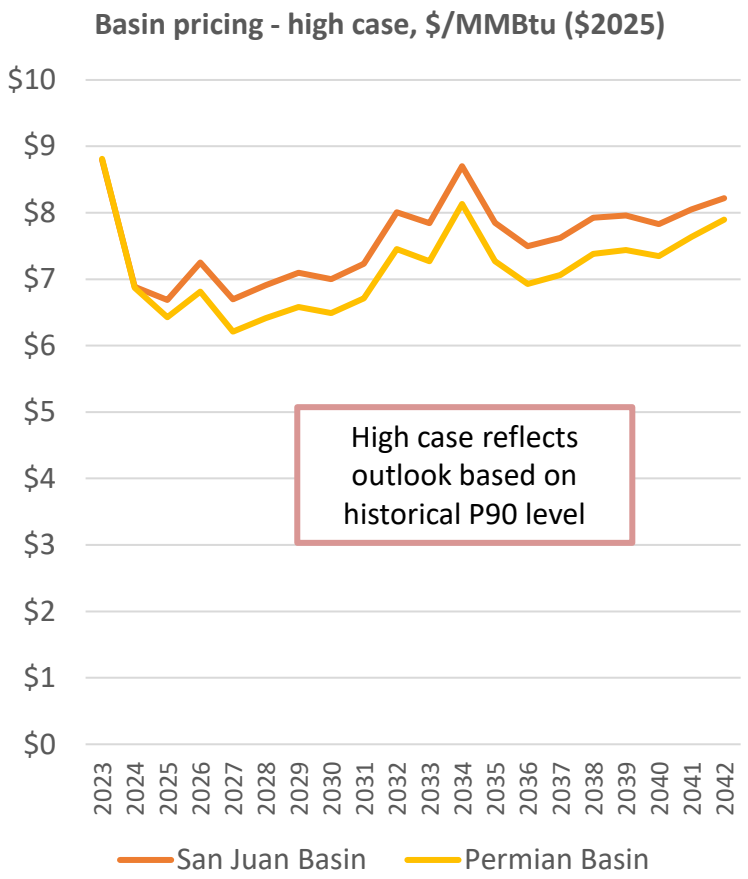
APPENDIX: ADDITIONAL DETAIL ON SELECTED INPUTS

PNM Talk to us. PNM.com

NATURAL GAS PRICING SUMMARY



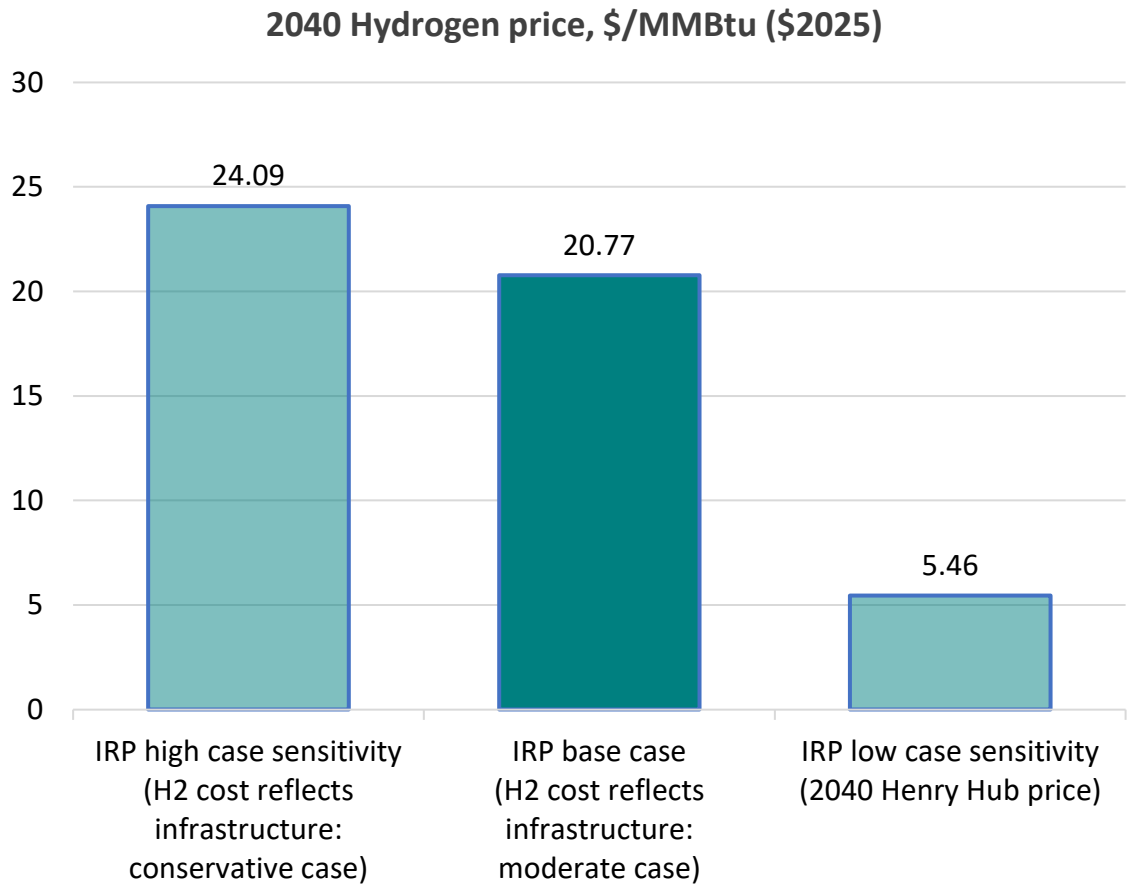




Natural gas pricing provided by Siemens

PNM Talk to us.

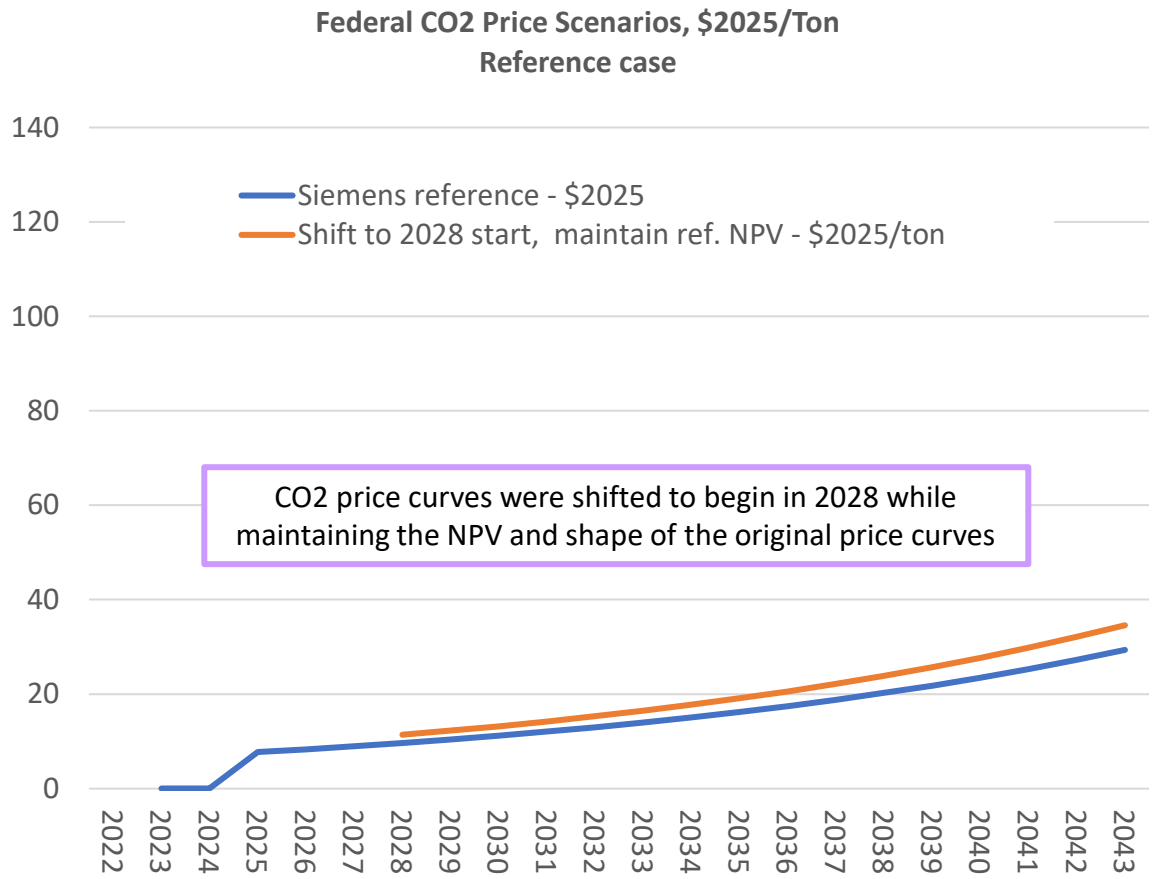
HYDROGEN PRICING SUMMARY – HYDROGEN PRICE TO BE UTILIZED IN 2040 AND BEYOND

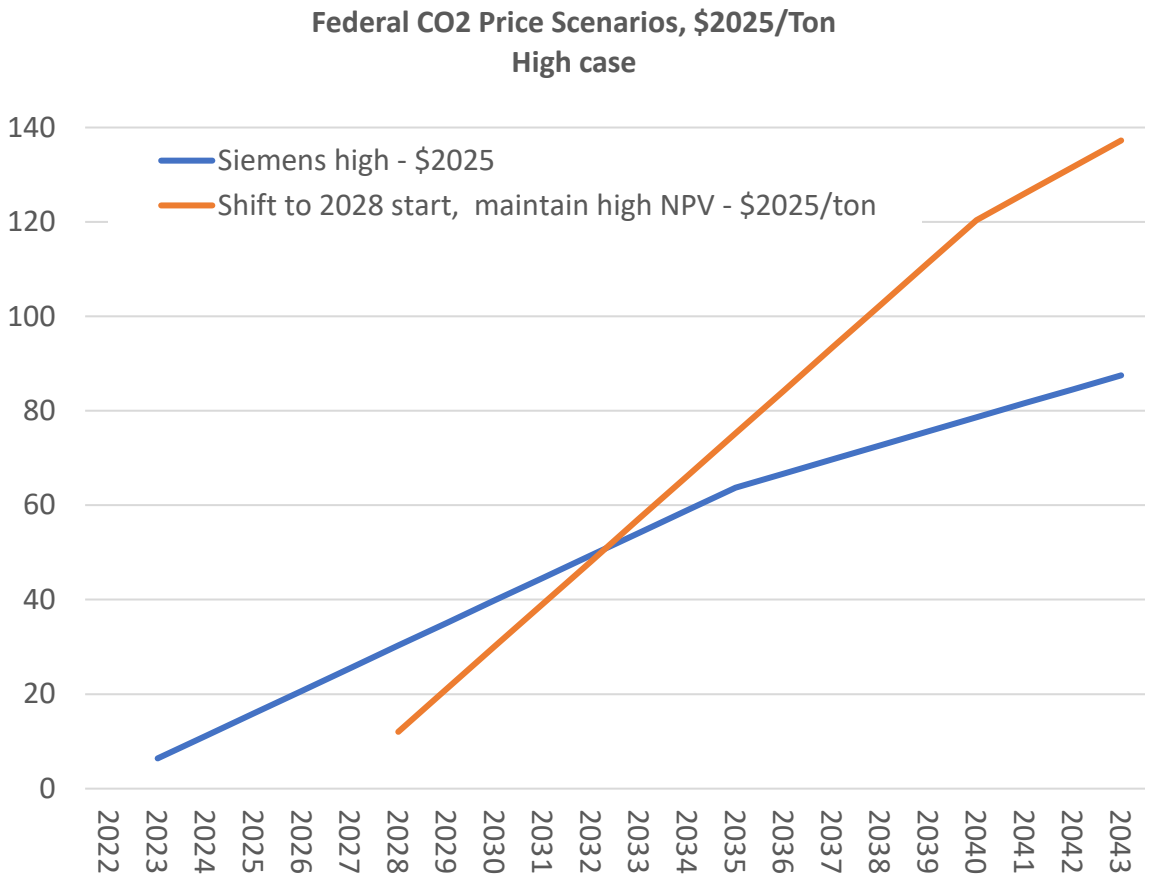


Hydrogen pricing developed by E3

- Natural gas scenarios assume that plants capable of burning hydrogen will be converted beginning in 2040
- In these cases, hydrogen is assumed to be available via pipeline, and utilization incurs a fuel cost
- Hydrogen pricing in 2040 and beyond is uncertain today
- E3 developed hydrogen pricing that reflects a levelized cost of new hydrogen production infrastructure each year (2040 estimate shown here)
- Actual commodity price is still unknown, and may not track levelized cost of new infrastructure
- PNM will also run sensitivities under which hydrogen is priced using natural gas as a benchmark – specifically, a scenario in which hydrogen has a floor price set by natural gas

CO2 PRICING SUMMARY





Carbon prices provided by Siemens; PNM adjustments

TRANSMISSION COST ADDERS

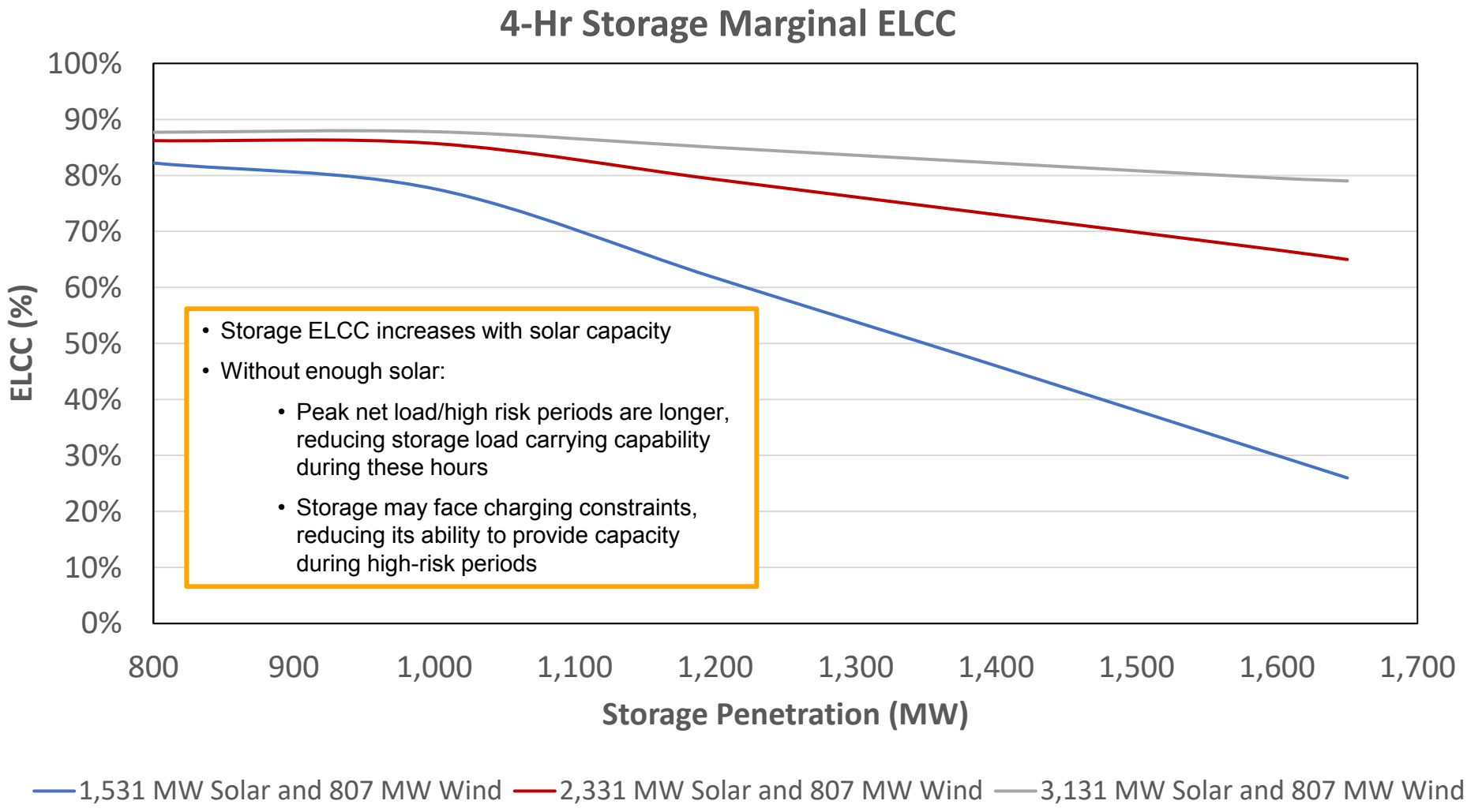
Assumptions:

- Transmission costs include interconnection and delivery costs
- Cost reflect total project cost
- Zonal transmission adders to be combined with zonal generic resource costs to determine total resource cost to portfolio in expansion plans

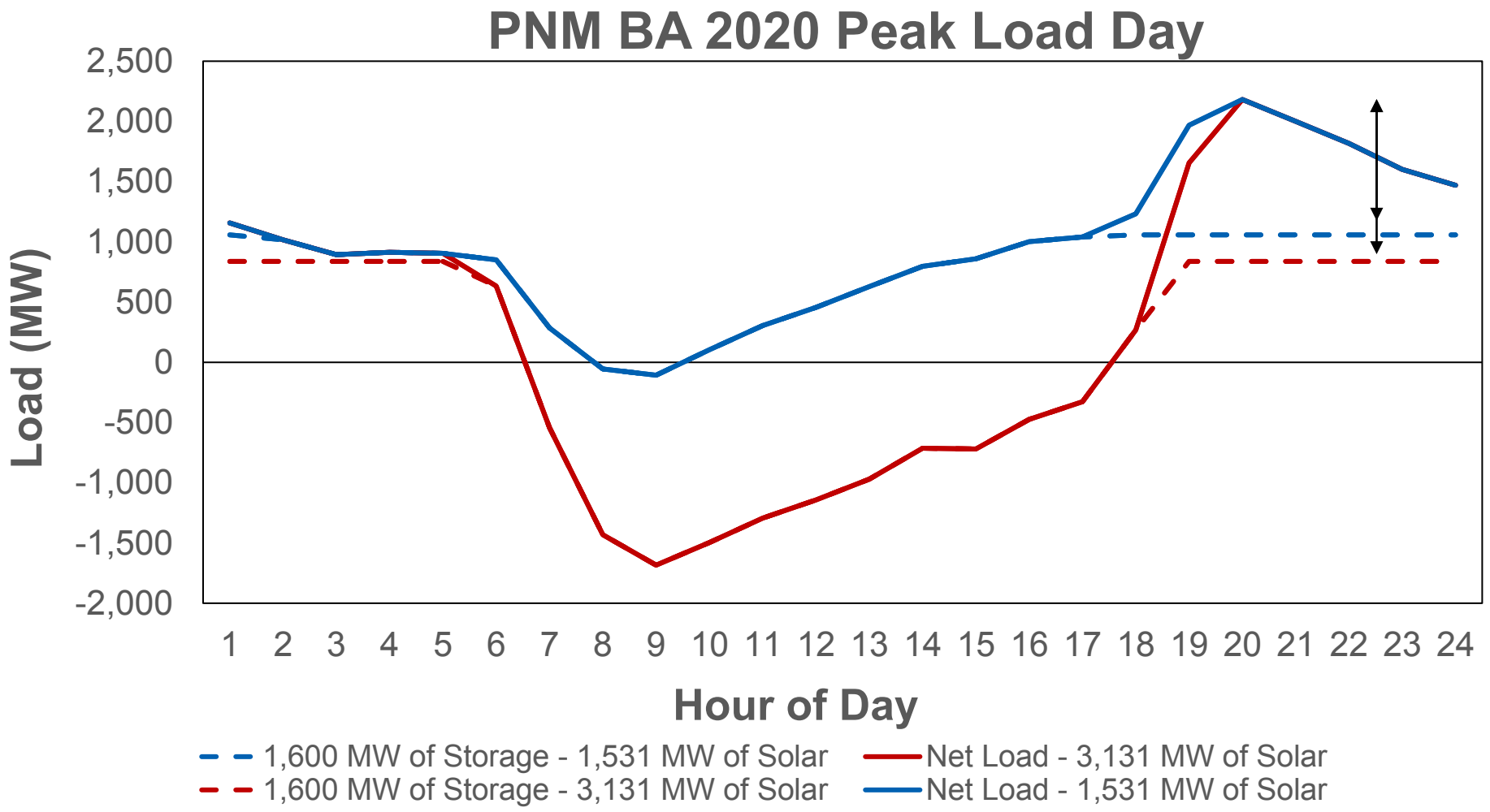
	$2025	$2025	$2025	$2025	$2025	$2025	$2025
	Loadside	North (1st 600 MW)	North (2nd 600 MW)	North (3rd 600 MW)	South	West	East
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	$248	$137	$267	$638	$-	$500	$324
2026	$248	$137	$267	$638	$-	$500	$324
2027	$248	$137	$267	$638	$-	$500	$324
2028	$248	$137	$267	$638	$-	$500	$324
2029	$248	$137	$267	$638	$-	$500	$324
2030	$248	$137	$267	$638	$-	$500	$324
2031	$248	$137	$267	$638	$-	$500	$324
2032	$248	$137	$267	$638	$-	$500	$324
2033	$248	$137	$267	$638	$-	$500	$324
2034	$248	$137	$267	$638	$-	$500	$324
2035	$248	$137	$267	$638	$-	$500	$324
2036	$248	$137	$267	$638	$-	$500	$324
2037	$248	$137	$267	$638	$-	$500	$324
2038	$248	$137	$267	$638	$-	$500	$324
2039	$248	$137	$267	$638	$-	$500	$324
2040	$248	$137	$267	$638	$-	$500	$324
2041	$248	$137	$267	$638	$-	$500	$324
2042	$248	$137	$267	$638	$-	$500	$324

Transmission cost adders developed by PNM

Marginal ELCCs: 4-Hr Storage

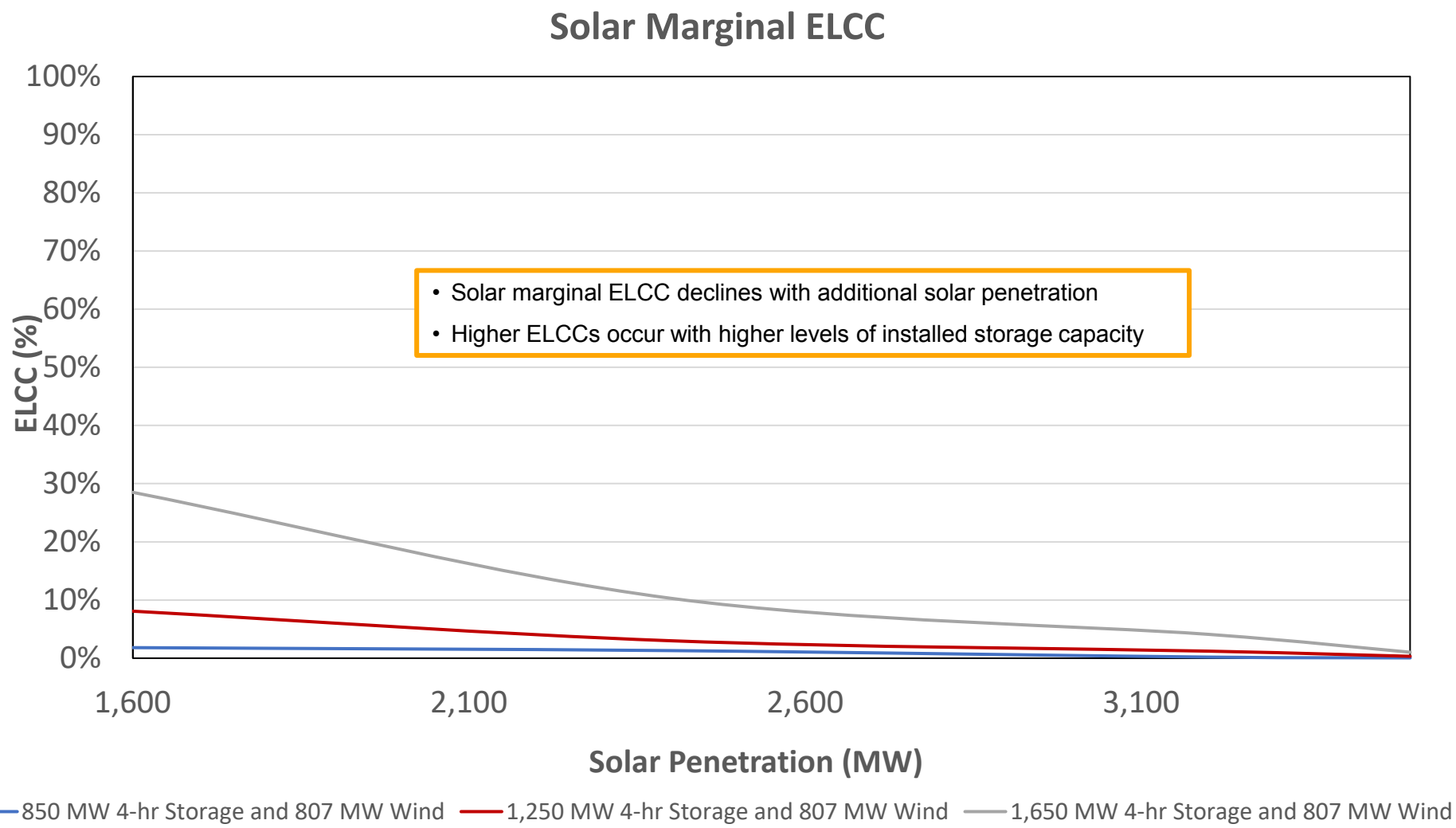


Net Load Shape Analysis – 1,600 MW of Storage under 2 Solar Scenarios

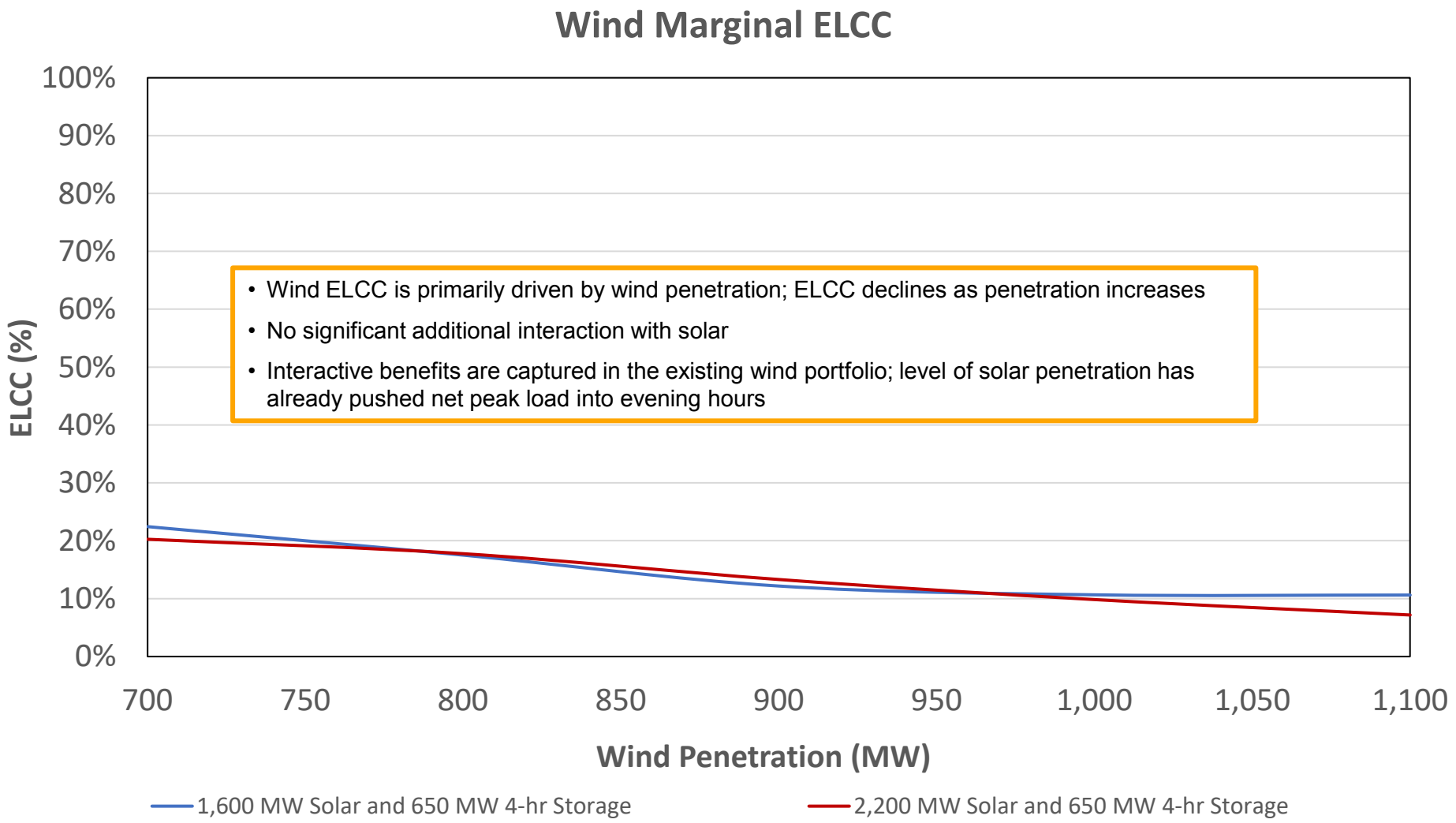


- Additional solar pushes net load down during the day
- Peak net load hour is the same regardless of solar capacity, because it occurs after sundown
- Peak net load/high risk period is shorter in the high solar case – more solar pushes the high-risk period beyond sunset
- Storage ELCC is greater in the higher solar case because storage is better able to cover the shorter risk period
- Charging not shown on chart, but 1,600 MW of storage sees charging constraints in the baseline solar case

Marginal ELCCs: Solar



Marginal ELCCs: Wind



Acronym List

ADMS	Advanced Distribution Monitoring System
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Company
ATB	Annual Technologies Baseline
BA	Balancing authority
BAA	Balancing authority area
BTM	Behind the meter
Btu	British thermal unit
CAA	Clean Air Act
CAISO	California Independent System Operator
CAES	Compressed Air Energy Storage
CCGT	Combined cycle gas turbine
CCN	Certificate of Convenience & Necessity
COP	Conference of the Parties
CT	Combustion turbine
DCS	Disturbance Control Standard
DERMS	Distributed Energy Resource Management System
DG	Distributed generation
DR	Demand response
DSM	Demand Side Management
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EEA	Energy Emergency Alert
EIM	Energy Imbalance Market
EIP	Eastern Interconnection Project
ELCC	Effective load carrying capability
EPA	Environmental Protection Agency
EPE	El Paso Electric Company
EPNG	El Paso Natural Gas Company
ETA	Energy Transition Act
EUEA	Efficient Use of Energy Act 62-17 NMSA
EUE	Expected Unserved Energy
EV	Electric vehicle
FCPP	Four Corners Power Plan
FERC	Federal Energy Regulatory Commission
GE	General Electric Company
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hours
HE	Hour ending
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITC	Investment tax credit
kW	Kilowatt
kWh	Kilowatt-hours
LADWP	Los Angeles Department of Water & Power
LIHEAP	Low Income Home Energy Assistance Program
LOLE	Loss of load expectation
LOLH	Loss of load hours
MCEP	Most Cost-Effective Portfolio
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hours
NEM	Net energy metering
NERC	North American Electric Reliability Council
NPV	Net present value
NMAC	New Mexico Administrative Code
NMPRC	New Mexico Public Regulatory Commission
NMWEC	New Mexico Wind Energy Center
NRC	Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company
OATT	Open Access Transmission Tariff
PNM	Public Service Co. of New Mexico
PNMR	PNM Resources, Inc.
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PTC	Production tax credit
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
REC	Renewable Energy Certificate
RFI	Request for Information
RFP	Request for Proposals
RPS	Renewables Portfolio Standard
SERVM	Strategic Energy Risk Valuation Model
SCPPA	Southern California Public Power Authority
SJGS	San Juan Generating Station
SMR	Small modular reactor
SPS	Southwestern Public Service Co.
SRSG	Southwest Reserve Sharing Group
SWAT	Southwest Area Transmission
TEP	Tucson Electric Power
TOD	Time of day
TSGT	Tri-State Generation and Transmission Association
UCAP	Unforced capacity
UCT	Utility cost test
UNFCCC	United Nations Framework Convention on Climate Change
WAPA	Western Area Power Administration
WECC	Western Electric Reliability Council

RENEWABLE ENERGY RESOURCES

Resource	TRL	Development lead time	Capital cost, $/kW ($2022)	Other considerations
Solar	9	<2 years	$1,269[1]	PTC more beneficial than ITC
Wind	9	<2 years	$1,713[1]	Eligible for PTC

THERMAL ENERGY RESOURCES

Resource	TRL	Development lead time	Capital cost, $/kW ($2022)	Other considerations
Aeroderivative gas CT	9	Up to ~5 years	$1,280[1]	Conversion to CO2-free fuel
Linear generator units	8	<2 years	$2,068[2]	Conversion to CO2-free fuel

1. Cost for 2025 delivery (reflects 2023 cost estimate); utilizes Siemens forecast reported in $2021, converted to $2022 assuming 8.0% inflation in 2022
2. Siemens forecast for 2025, initially reported in $2021 and converted to $2022 assuming 8.0% inflation in 2022

Draft of 5/12/2023

ENERGY STORAGE RESOURCES

Resource	TRL	Development lead time	Capital cost, $/kW ($2022)	Other considerations
Lithium-ion battery	9	<3 years	$1,491[1]	Best suited for shorter-duration solutions (30 minutes to 4 hours); storage ITC
Redox-flow battery	8	<5 years	$4,254[2]	Best suited for longer-duration solutions (8-12 hours); storage ITC
Iron-air storage	8	<5 years	$2,228[2]	Very-long duration/seasonal storage (100 hours); storage ITC
Pumped-hydro storage (10-hr)	9	5+ years	$3,577[2]	Specific siting requirements, long duration (8-70 hours); storage ITC
Compressed air energy storage (Adiabatic, 24-hrs)	9	5+ years	~$2,300[3]	Specific siting requirements, long duration; storage ITC
Liquified air energy storage	7-8	5+ years	$3,147 [2]	Long duration (~6-20 hours); storage ITC
Thermal energy storage	5	5+ years	~$800 for thermal storage component[2]	Utilized with existing infrastructure; long duration (4-168 hours); significant assumptions for modeling; storage ITC
Green hydrogen	5-6	5+ years	$1,100 for electrolyzers, $337/kW for CT conversion[2]	Significant uncertainties around necessary CT upgrades to allow for 100% hydrogen combustion; uncertainties exist regarding storage/transport; PTC/ITC

1. Cost for 2025 delivery (reflects 2023 cost estimate); utilizes Siemens forecast reported in $2021, converted to $2022 assuming 8.0% inflation in 2022
2. Siemens forecast for 2025, initially reported in $2021 and converted to $2022 assuming 8.0% inflation in 2022
3. E3 estimate for 24-hr A-CAES 2030 capital cost (E3 *CPUC IRP Zero-Carbon Technology Assessment)*

Draft as of 5/12/2023

CARBON CAPTURE RESOURCES

Resource	TRL	Development lead time	Capital cost, $/kW ($2022)	Other considerations
Post combustion carbon-capture	8	Up to 5 years	$2,500-3,200[1]	Utilized with existing infrastructure; ~99% carbon capture, uncertainties around CO2 storage/transport
NET power plant	7	5+ years	$2,649[2]	Uncertainty around treatment of post-production carbon stream – likely need to sequester

1. E3 estimate for 2030 capital cost for ~99% carbon capture; ~90% carbon capture estimated to cost $2,500-3,000/kW in 2030 (E3 *CPUC IRP Zero-Carbon Technology Assessment)*
2. Siemens forecast for 2025, initially reported in $2021 and converted to $2022 assuming 8.0% inflation in 2022

Printed: 5/12/2023

DISTRIBUTED ENERGY RESOURCES, ENERGY EFFICIENCY, AND DEMAND RESPONSE

Resource	TRL	Development lead time	2025 capital cost, $/kW ($2022)	Other considerations
BTM solar and/or storage	9	<2 years	NA	Currently a load modifier, could act like system resource with DERMS/AMI
Energy efficiency	9	<2 years	Multiple bundles ranging in price	Finite potential; treated as load modifier
Demand response	9	<2 years	~$115-kW-year*	Modeled as system resource

* PNM is currently reviewing additional information regarding DR costs

Uncontrolled as of 5/12/2023

OTHER RESOURCES NOT MODELED IN 2023 IRP

Resource	TRL	Development lead time	2025 capital cost, $/kW ($2022)	Other considerations
Geothermal	9	5+ years	$7,800-9,800 (standard)[1]	Dispatchable, high-cost
Concentrated solar with thermal energy storage	8	5+ years	$6,579[2]	ITC/PTC; ~10 hours of storage; cost-prohibitive
Small modular nuclear reactor	6-7	5-10 years	$9,944[2]	Nuclear PTC; 80% RPS limits carbon-free energy from other sources
Gravity energy storage	8	5+ years	$5,535[2]	Specific siting requirements; 2-18 hours of duration; storage ITC; cost-prohibitive

1. E3 estimate for 2030 capital cost; enhanced geothermal plant cost estimated to be ~$9,000-52,000/kW (E3 *CPUC IRP Zero-Carbon Technology Assessment)*
2. Siemens forecast for 2025, initially reported in $2021 and converted to $2022 assuming 8.0% inflation in 2022

Printed: 5/12/2023

Phase 1: simple scenario screen (individual technologies)

Screen scenarios under the following futures

CT&P future

- P50 load 8760 production cost run
- Extreme weather load 8760 production cost run

CT&P + Stable ED Growth

- P50 load 8760 production cost run
- Extreme weather load 8760 production cost run

Scenarios (additions of RFI technologies occur 2028-2033)

(Base technologies include wind, solar, 4-hr li-ion storage, energy efficiency, demand response; EnCompass capacity expansion modeling optimizes installed capacity of base technologies in each scenario)

1. Base technologies only
2. Base + Pumped hydro storage 70-hr (NW NM)
3. Base + Pumped hydro storage 8-hr (NW NM)
4. Base + Iron-air storage
5. Base + CAES (+transmission adder for salt access)
6. Base + LAES
7. Base + flow battery
8. Base + thermal storage (with steam turbine)
9. Base + CTs
10. Base + linear generators
11. Base + wind expansion (transmission + 800 MW wind)
12. Base + carbon capture retrofit (Afton)
13. Base + NET power plant
14. Base + 250 MW hydrogen project
15. Base + 500 MW hydrogen project

Evaluate scenarios based on:

a) Overall cost
b) Cost difference to incorporate strong ED growth
c) Ability to accommodate extreme weather load

Other (qualitative) considerations for reporting:

- *TRL*
- *Similarities to other technologies evaluated*

Rank all scenarios based on evaluation criteria.

Phase 2: complex scenario evaluation (multiple technologies)

Determine complex scenarios

- Combine technologies in portfolios for EnCompass optimization (identify technologies that are likely to complement each other; additions of RFI technologies occur 2028-2033)
    - Base technologies, 70-hr PHS, CTs
    - Base technologies, 70-hr PHS, linear generator
    - Base technologies, 70-hr PHS, CTs, transmission expansion + eastern wind
    - Base technologies, 70-hr PHS, carbon capture (>99%)
    - Base technologies, 8-hr PHS, CTs
    - Base technologies, 8-hr PHS, linear generator
    - Base technologies, 8-hr PHS, CTs, transmission expansion + eastern wind
    - Base technologies, 8-hr PHS, carbon capture (>99%)
    - Base technologies, Iron-air storage, CTs
    - Base technologies, Iron-air storage, linear generator
    - Base technologies, Iron-air storage, CTs, transmission expansion + eastern wind
    - Base technologies, Iron-air storage, carbon-capture (>99%)
    - Base technologies, transmission expansion + wind + CAES
    - Base technologies + transmission expansion + eastern wind & co-located battery storage

Screen scenarios under the following futures

CT&P future

- P50 load 8760 production cost run
- Extreme weather load 8760 production cost run

CT&P + Stable ED Growth

- P50 load 8760 production cost run
- Extreme weather load 8760 production cost run

Evaluate scenarios based on:

d) Overall cost
e) Cost difference to incorporate strong ED growth
f) Ability to accommodate extreme weather load

Other (qualitative) considerations for reporting:

- *TRL*
- *Diversity benefits between technologies/operating characteristics represented among portfolios*

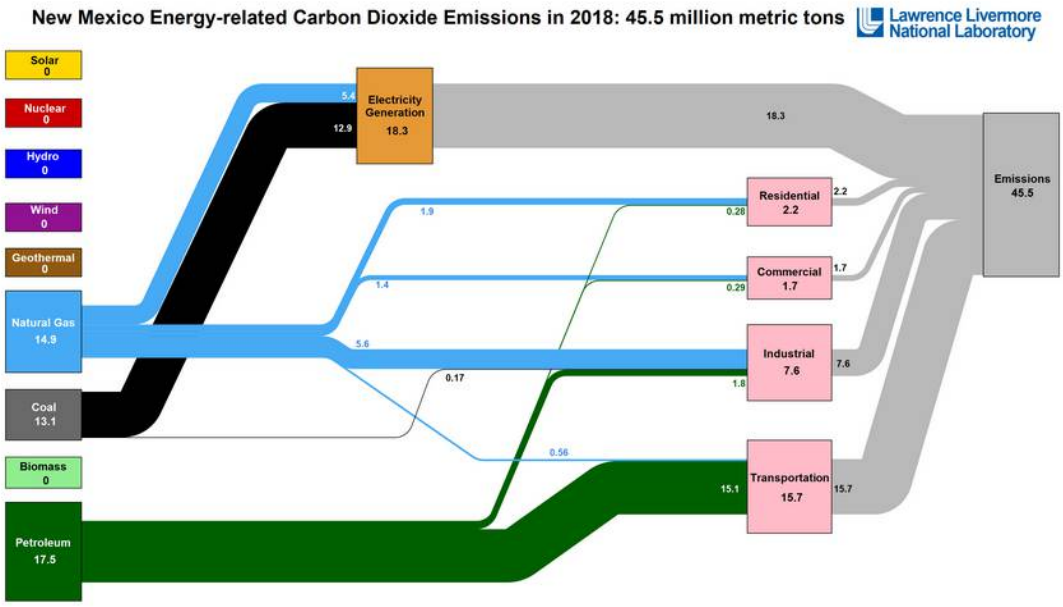
Rank all scenarios based on evaluation criteria.

Phase 3: evaluate selected complex and/or simple scenarios against all futures and additional selected sensitivities

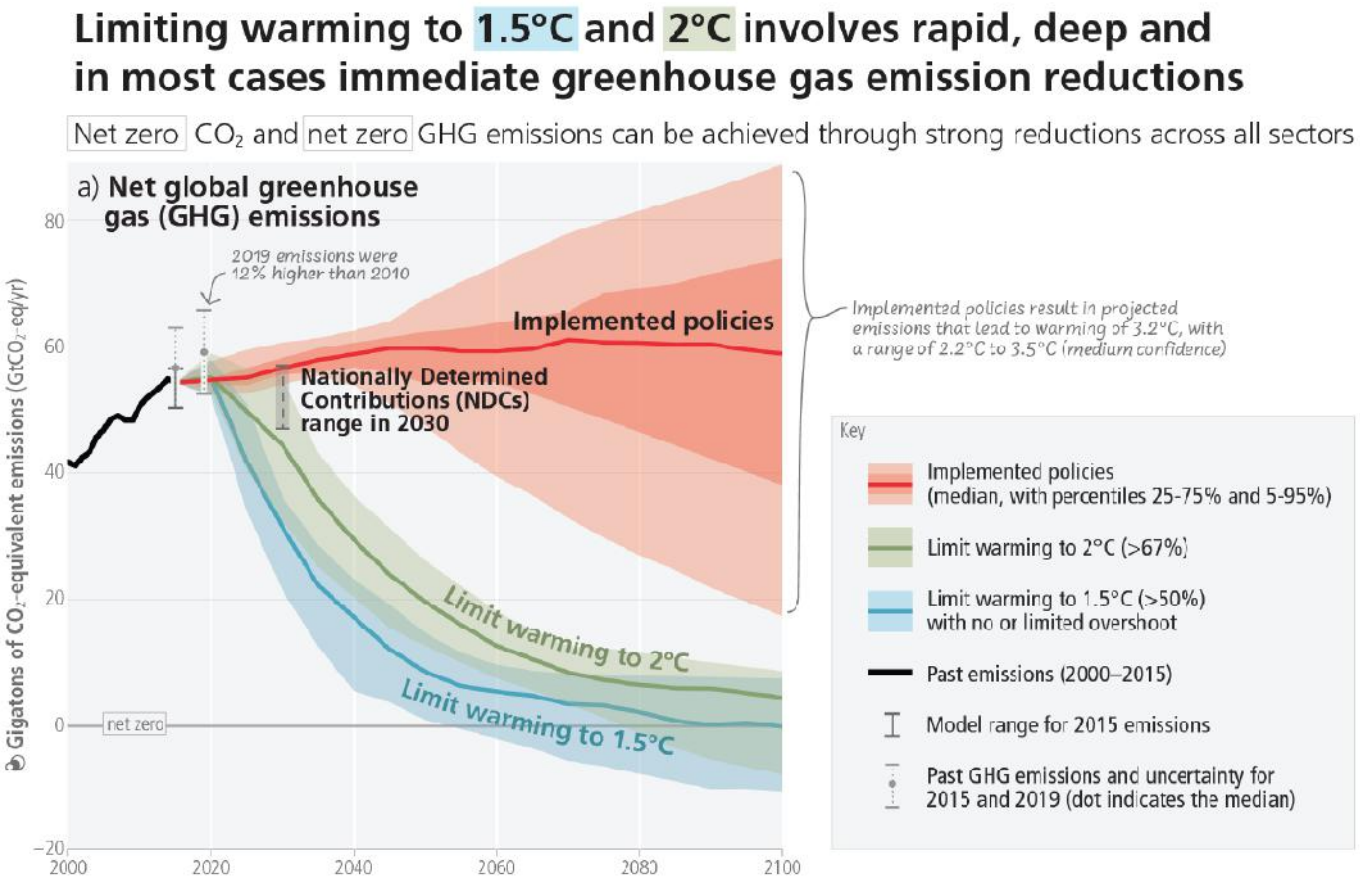
Futures and sensitivities:

Future	**Sensitivities**
Current trends & policy	Technology costs (high/low), economic development (accelerated), TOU rates, natural gas prices (high/low, applies to scenarios with natural gas), carbon prices (NMPRC prices), IRA tax credits expire
High economic growth	Technology costs (high/low), economic development (stable)
Low economic growth	Technology costs (high/low), no carbon price
National carbon policy	Technology costs (high/low), economic development (accelerated)

Climate Action 2023-2033



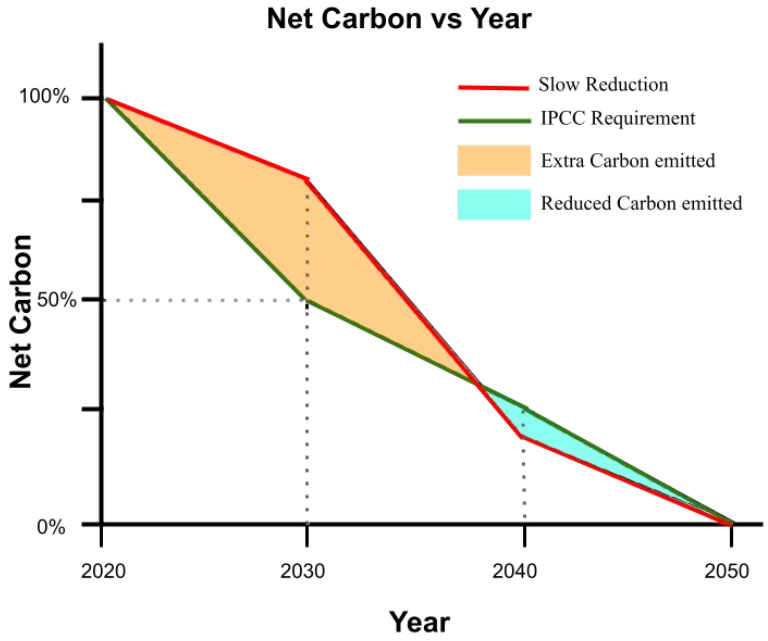
Methane waste emissions from the oil and gas (O/G) industry are not included on the left. Methane, in the short term, is 150-200 times more potent greenhouse gas than CO_2. Estimates are that in 2021 O/G operations emitted 1.1 mmt…160 mmt eq CO_2!



Mar 2023 IPCC report analysis - https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23

Climate Action 2023-2033

The Journey Matters as Much as the Destination



By Solargetic Designs, LLC

NM can reduce carbon emissions ASAP by:

1. Moving to solar/wind (and maybe some geothermal) with carbon-free energy storage for electricity generation.
2. Electrify our transportation sector
3. Electrify our industrial sector
4. Plug underperforming O/G wells

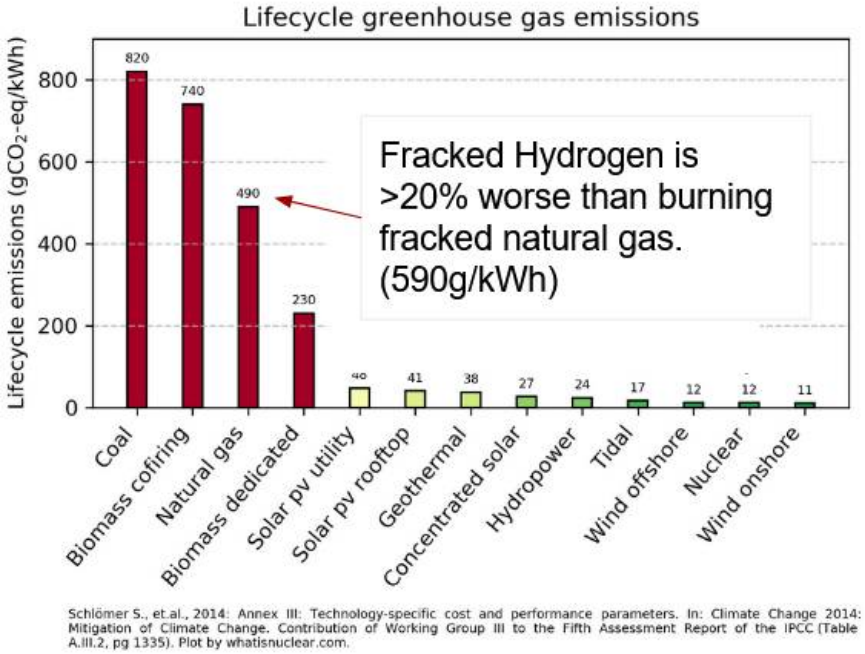
Individuals can make a personal commitment to:

1. Limit flying until airlines commit to reducing their emissions
2. Use pedal power, electrify their vehicle, and/or use mass transit
3. Electrify/solarize water and space heating
4. Electrify/solarize cooking (for better indoor air quality, as well)
5. Buy local

Don't get distracted by false or fluff solutions like:

1. Hydrogen for electric generation, especially if it will be made with carbon-based materials.
2. Direct Air Carbon Capture & Sequestration
3. Vegetative, ocean or soil, carbon sequestration
4. Regenerative Farming
5. Plastic Waste reduction

All these efforts detract from the main efforts needed and have little to no impact on net fossil fuel emission reduction.



Happy Earth Decade

SANDIA REPORT
SAND2022-0583
Printed January 2022

Sandia National Laboratories

Probabilistic Modeling of Climate Change Impacts on Renewable Energy and Storage Requirements for NM's Energy Transition Act

Clifford K. Ho, Erika L. Roesler, Tu Nguyen, and James Ellison

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico
87185 and Livermore,
California 94550

Issued by Sandia National Laboratories, operated for the United States Department of Energy by National Technology & Engineering Solutions of Sandia, LLC.

NOTICE: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees, nor any of their contractors, subcontractors, or their employees, make any warranty, express or implied, or assume any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represent that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government, any agency thereof, or any of their contractors or subcontractors. The views and opinions expressed herein do not necessarily state or reflect those of the United States Government, any agency thereof, or any of their contractors.

Printed in the United States of America. This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831

Telephone: (865) 576-8401
Facsimile: (865) 576-5728
E-Mail: reports@osti.gov
Online ordering: http://www.osti.gov/scitech

Available to the public from
U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Rd
Alexandria, VA 22312

Telephone: (800) 553-6847
Facsimile: (703) 605-6900
E-Mail: orders@ntis.gov
Online order: https://classic.ntis.gov/help/order-methods/



ABSTRACT

This report provides a study of the potential impacts of climate change on intermittent renewable energy resources, battery storage, and resource adequacy in Public Service Company of New Mexico's Integrated Resource Plan for 2020 – 2040. Climate change models and available data were first evaluated to determine uncertainty and potential changes in solar irradiance, temperature, and wind speed in NM in the coming decades. These changes were then implemented in solar and wind energy models to determine impacts on renewable energy resources in NM. Results for the extreme climate-change scenario show that the projected wind power may decrease by ~13% due to projected decreases in wind speed. Projected solar power may decrease by ~4% due to decreases in irradiance and increases in temperature in NM. Uncertainty in these climate-induced changes in wind and solar resources was accommodated in probabilistic models assuming uniform distributions in the annual reductions in solar and wind resources. Uncertainty in battery storage performance was also evaluated based on increased temperature, capacity fade, and degradation in round-trip efficiency. The hourly energy balance was determined throughout the year given uncertainties in the renewable energy resources and energy storage. The loss of load expectation (LOLE) was evaluated for the 2040 No New Combustion portfolio and found to increase from 0 days/year to a median value of ~2 days/year due to potential reductions in renewable energy resources and battery storage performance and capacity. A rank-regression analyses revealed that battery round-trip efficiency was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. An increase in battery storage capacity to ~25,000 – 30,000 MWh from a baseline value of ~14,000 MWh was required to reduce the median value of LOLE to ~0.2 days/year with consideration of potential climate impacts and battery degradation.

ACKNOWLEDGEMENTS

The authors thank Nick Phillips from PNM for providing data and consultation regarding this work. This work was funded by the Climate Change Security Center program (278/40.02.01.04.02.01.06) at Sandia National Laboratories (Center 8900).

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Sandia National Laboratories is a multimission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC., a wholly owned subsidiary of Honeywell International, Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA0003525.

CONTENTS

1. Introduction and Objectives 9
   1.1. Background and Problem Statement 9
   1.2. Objectives 9
   1.3. Overview of Report 10
2. Climate Change Modeling 11
   2.1. Climate Data Source and Methods 11
   2.2. Results and Discussion 14
   2.3. Comparison with Other Studies 16
   2.4. Next Steps 17
3. Climate Change Impacts on Solar and Wind Power Generation 19
   3.1. Wind and Solar Resources in New Mexico 19
   3.2. Impact of Modeled Climate Change on PNM Wind Power Generation 19
      3.2.1. Methodology 19
   3.3. Impact of Modeled Climate Change on PNM Solar Power Generation 21
      3.3.1. Climate Scenario Selection 21
      3.3.2. Methodology – Specific Method 22
      3.3.3. Methodology – General Method 23
4. Climate Change Impacts on Battery Storage 25
   4.1. Impact of Temperature Change on Battery Storage 25
   4.2. Impacts of Capacity Fade and Round-Trip Efficiency on Battery Storage 27
   4.3. Implementation into QuEST 28
5. Probabilistic Analysis of Climate Change Impacts and Battery Performance 29
   5.1. Modeling Approach 29
      5.1.1. Uncertainty in Wind Energy Resources 31
      5.1.2. Uncertainty in Solar Energy Resources 33
      5.1.3. Uncertainty in Battery Storage Resources 34
      5.1.4. Annual Energy Load 35
   5.2. Modeling Results 36
6. Conclusion and Recommendations 41
   6.1. Climate Modeling 41
   6.2. Climate Impacts on Wind and Solar Energy Resources 41
   6.3. Climate Impacts on Battery Performance and Storage 41
   6.4. Energy Balance and Climate Impacts on LOLE 42

LIST OF FIGURES

Figure 1. PNM 2040 portfolios for carbon-free electricity production in 2040 [1]. 9
Figure 2. Contour plots of the annual mean of the entire simulation from the E3SM CMIP5 data. Top to bottom are the 'No Climate Change' (ECA_piControl), 'Low Climate Change' (historical), and 'High Climate Change' (SSP585) simulations. Variables of interest for this study included (left to right) Surface Downwelling Shortwave Radiation, Surface Temperature, and Near-Surface Wind Speed 12
Figure 3. Time series of the surface downwelling shortwave radiation, surface temperature, and near-surface wind speed for the 'No Climate Change' (ECA_piControl), 'Low

Climate Change' (historical), 'High Climate Change' (SSP585) CMIP6 E3SM simulations for global, contiguous United States, and New Mexico areas. The time series represents monthly means from the simulation data, and the data were smoothed by applying a 48-point running average. 14
Figure 4. Probability Distribution Functions of the time-averaged and spatially-averaged (over New Mexico) of (top to bottom) surface downwelling shortwave radiation, surface temperature, and near-surface wind speed for the three simulations scenarios in the CMIP6 E3SM database. 15
Figure 5. Power Curve for IEC Class II Turbine 20
Figure 6. Cumulative distribution functions of climate-induced changes in wind and solar resources (top) and uncertainty in battery performance (RTE and capacity fade; bottom). 31
Figure 7. Plot of historical average capacity factors for PNM wind energy resources by hour and month (2013 – 2019) [1]. 32
Figure 8. Plot of historical average capacity factors for PNM solar energy resources by hour and month (2013 – 2019) [1]. 34
Figure 9. Cumulative probability of loss of load expectation (LOLE) with inclusion of solar and wind resource uncertainty resulting from climate change and uncertainty in battery performance. Uniform distributions of ±25% (top) and ±50% (bottom) were assumed for the solar, wind, and battery performance uncertainty distributions. 37
Figure 10. Impact of uncertainties in solar and wind resources and battery performance resulting from climate change on LOLE. Standardized rank regression coefficients are shown. Uniform distributions of ±50% were assumed for the solar, wind, and battery performance uncertainty distributions. 38
Figure 11. Impact of uncertainties in solar and wind resources and battery performance resulting from climate change on LOLE variability. Incremental coefficients of determination are shown. Uniform distributions of ±50% were assumed for the solar, wind, and battery performance uncertainty distributions. 38
Figure 12. Cumulative probability of LOLE with increased battery storage capacity of 100,000 MWh (from 14,328 MWh) resulting in a 95% confidence that the LOLE would be ≤ 0.2 days/year for assumed uncertainties in solar, wind, and battery performance. 39

LIST OF TABLES

Table 1. Description of data sources from simulations used for three climate change scenarios over New Mexico. 11
Table 2. List of Variables for used to determine resources uncertainty for solar, wind, and battery. 13
Table 3. Averages and Standard Deviations of solar radiation, surface temperature, and surface wind from E3SM CMIP6 scenarios. 16
Table 4. Wind Resources in New Mexico. 19
Table 5. List of PRC-approved and pending-approval large solar arrays in New Mexico. 19
Table 6. IEC Wind Turbine Classes 20
Table 7. Solar PV Scenarios and Results. 23
Table 8. Parameters used in HVAC modeling of BESS power consumption. 25

Table 9. Modeled annual HVAC energy consumption as a function of ambient temperature rise. 27
Table 10. Summary of firm fixed resources assumed for PNM 2040 No New Combustion scenario (in addition to solar and wind generation) [1]. 29
Table 11. Summary of uncertainty distributions in probabilistic simulations. 30
Table 12. Historical average capacity factors for PNM wind energy resources (2013 – 2019) [1]. 32
Table 13. Hourly baseline wind generation (MW) based on capacity factors in Table 12 and total prescribed wind generation capacity of 956 MW in the PNM IRP 2040 No New Combustion portfolio [1]. 33
Table 14. Historical average capacity factors for PNM solar energy resources (2013 – 2019) [1]. 33
Table 15. Hourly baseline solar generation (MW) based on capacity factors in Table 14 and total prescribed solar generation capacity of 3,165 MW in the PNM IRP 2040 No New Combustion portfolio [1]. 34
Table 16. Summary of planned battery storage systems in PNM's No New Combustion, most cost-effective portfolio [1]. 35
Table 17. Average hourly loads (MW)* by month using reference 2040 forecast (PNM 2020 – 2040 IRP [1]). 35

This Page Left Blank

1. INTRODUCTION AND OBJECTIVES

1.1. Background and Problem Statement

In January 2021, the Public Service Company of New Mexico (PNM) issued its fifth Integrated Resource Plan (IRP), "PNM 2020-2040 Integrated Resource Plan," which included carbon-free electricity generation portfolios by 2040 [1]. PNM is a regulated utility and NM's largest energy provider with currently over 500,000 residential and business customers and ~3 GW of generation capacity. The PNM 2020-2040 IRP included portfolios to meet NM's Energy Transition Act, which requires 100% of electricity generation to be carbon free by 2045. PNM intends to meet that goal by 2040 and includes two different portfolios: a Technology Neutral scenario that includes hydrogen combustion turbines (initially powered by natural gas through the 2020s), and a No New Combustion scenario that relies primarily on solar, wind, and battery storage (Figure 1).

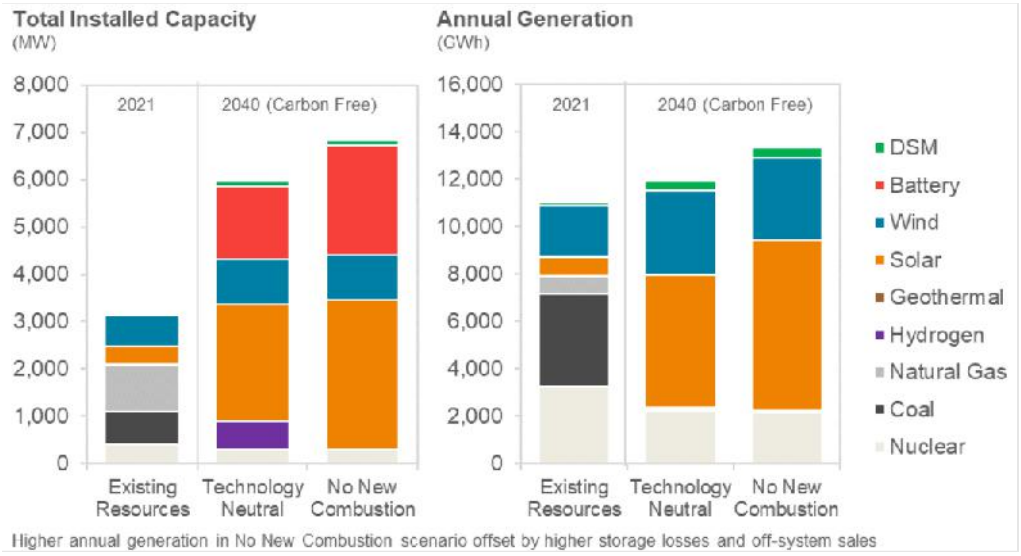


Figure 1. PNM 2040 portfolios for carbon-free electricity production in 2040 [1].

In the PNM 2020-2040 IRP, treatment of uncertainty and sensitivity analyses focused primarily on demand-side uncertainty. Climate change and potential impacts on intermittent wind and solar resources were not considered. In addition, uncertainties in large-scale, long-term performance and reliability of battery storage systems were not considered; the battery storage system was assumed to operate at nameplate capacity for its entire 20-year lifetime (due to contracted maintenance and servicing of the systems).

1.2. Objectives

The objectives of this study were to develop a probabilistic model and framework to evaluate inherent uncertainties in the energy resources and storage assumed in the PNM 2020-2040 IRP:

- Long-term changes in solar and wind resources caused by climate change
- Uncertainties in battery performance caused by capacity fade, degradation in round-trip efficiency, and long-term temperature increase caused by climate change
- Impact on the annual loss of load expectation (LOLE) and required energy storage

Probabilistic models were developed to evaluate the hourly energy balance each year given uncertainties in the renewable energy resources and energy storage. The loss of load expectation (LOLE) was probabilistically evaluated for the 2040 No New Combustion portfolio considering potential reductions in renewable energy resources and battery storage.

1.3. Overview of Report

Section 2 presents the climate data and methods that were used to determine potential climate-change impacts on solar irradiance, temperature, and wind speeds. Wind and solar resources are evaluated, and comparisons with other climate models are presented. Section 3 then evaluates the impact of the modeled climate change on PNM wind and solar power generation. Section 0 describes modeling to evaluate the potential impacts of climate change (increased temperatures), capacity fade, and round-trip efficiency degradation on battery performance. Section 5 describes a probabilistic model to evaluate the hourly energy balance with consideration of the inherent uncertainties in solar and wind resources, power generation, and battery storage on LOLE. Finally, Section 0 provides conclusions and recommendations for follow-on work.

2. CLIMATE CHANGE MODELING

2.1. Climate Data Source and Methods

Three simulations from the Department of Energy's Energy Exascale Earth System Model (E3SM) were chosen from the Earth System Grid Federation Climate Model Intercomparison Project – version 6 (CMIP6) repository [2-5]. The CMPI6 simulation set contains output contributed from Earth system modeling centers. This set includes simulations representing the Earth system response under various, prescribed forcing scenarios. For this study, the three simulations chosen were a baseline simulation called pre-industrial control (piControl), a moderately warming simulation called historical, and a highly warming simulation called SSP585. The three simulations were from the 'r1i1p1f1' variant identification, meaning the first realization, first initialization, and same physics and forcing. The data were all written in the form of monthly averages with more details below.

The baseline simulations include prescribed greenhouse gas concentrations, such as CO_2, set to values at a time in human history where anthropogenic signatures were not distinguishable on the temperature of the atmosphere. These baseline simulations start in the year 1850 and usually run with that concurrent year, 1850, for several hundred years. The purpose of the duration of these simulations is to emulate the Earth system climate variability and seasonality so that statistically significant values for a baseline, unperturbed Earth, can be compared against a simulated earth with increasing anthropogenic signatures such as increasing greenhouse gas concentrations. Table 1 lists the description of data used for the Preindustrial control, baseline data. Because this data set has no induced warming on the Earth system, it was also referred to as the 'no climate change' scenario for this work.

The historical simulation dataset, also described in Table 1, uses CO_2 concentrations prescribed or calculated from years 1850 to 2014. The Earth system will be warming due to increased greenhouse gas concentration build-up over this time period, so this dataset was referred to as the 'low climate change' scenario. The last simulation dataset used is called SSP585. It was developed as an update of the high-emission 'business as usual' IPCC RCP8.5 scenario [2, 5]. This dataset has the highest amount of warming of the three and is called 'high climate change' in this work.

Table 1. Description of data sources from simulations used for three climate change scenarios over New Mexico.

Scenario	Data and Simulation Description
No Climate Change	- ECA version of Preindustrial control simulation - CR-1.7 CMIP-6.2, ScenarioMIP - Concurrent year 1850 year for 165 years, monthly averages
Low Climate Change	- Update of RCP8.5 based on SSP5 - CR-1.7 CMIP-6.2, ScenarioMIP - Jan 1850 - Dec 2014, monthly averages
Extreme Climate Change	- Update of RCP8.5 based on SSP5 - CR-1.7 CMIP-6.2, ScenarioMIP - 1032 monthly-averaged time points, Jan 2015-Dec 2021

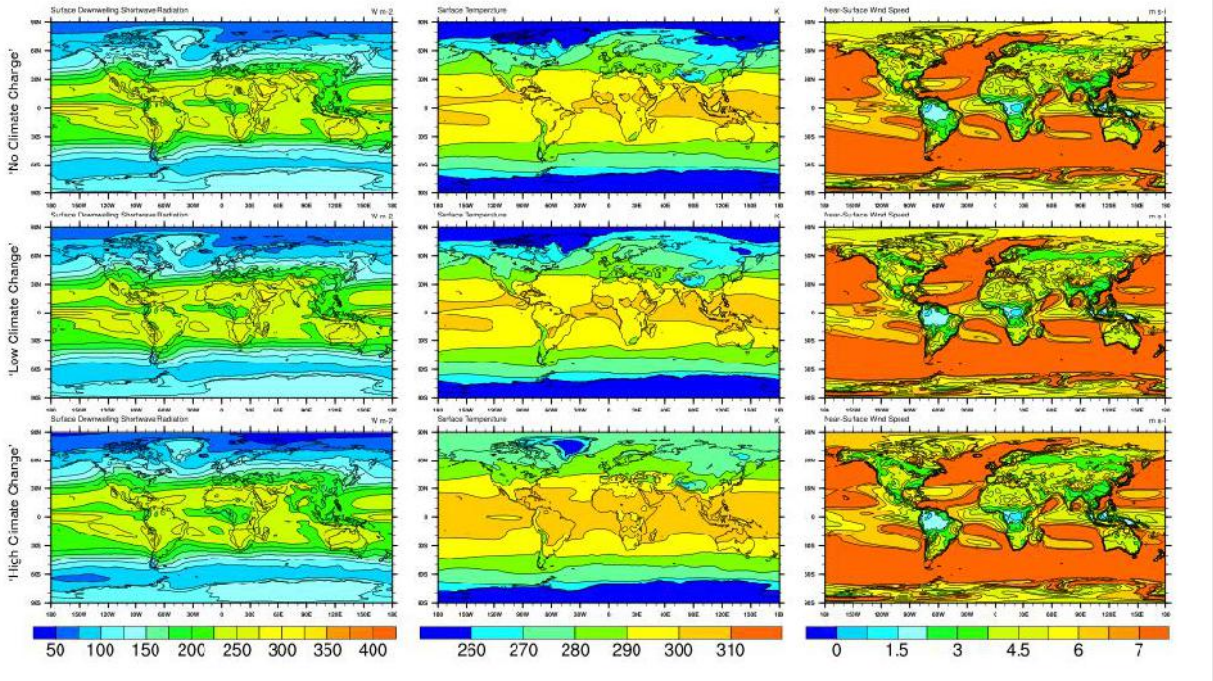


Figure 2. Contour plots of the annual mean of the entire simulation from the E3SM CMIP5 data. Top to bottom are the 'No Climate Change' (ECA_piControl), 'Low Climate Change' (historical), and 'High Climate Change' (SSP585) simulations. Variables of interest for this study included (left to right) Surface Downwelling Shortwave Radiation, Surface Temperature, and Near-Surface Wind Speed.

The variables chosen for analysis are fundamental variables influencing wind energy production, solar energy production, and battery storage efficiency. Table 2 lists the variables chosen from the E3SM CMIP6 database. For wind power generation, power is a function of wind speed cubed. The variable for near surface wind, sfcWind, was used instead of wind at hub height. 'sfcWind' is stated to be the wind at about 10 meters off the ground surface. It should be noted that the wind speed within the boundary layer generally follows a log wind profile as the surface frictional effects are less impactful as you move away from the surface. Therefore, any additional low level increase in height – 10s to 100s of meters will give 'generally' an increase in wind speed and therefore power. This variable was readily available and required no additional data processing after downloading.

Solar energy production from solar installations relies on direct and diffuse solar radiation. The potential for solar energy production is computed from the Global Horizontal Irradiance (GHI), which is the sum of Diffuse Horizontal Irradiance (DHI) and Direct Normal Irradiance (DNI) multiplied by the cosine of the solar zenith angle (z), $GHI = DHI + DNI \cdot \cos(z)$. Given radiation parameterizations in earth system models are column-based physics with no radiation interaction between columns, the surface downwelling shortwave radiation is associated with the needed GHI variable. Clear-sky shortwave radiation at the surface from climate models is DNI, but the diffuse radiation that could be scattered equally in all directions from molecules, aerosols, and clouds is more difficult to ascertain from earth system model output. Ground reflectance could also be included in GHI, but this contribution is usually low compared to DHI and DNI. It was determined that the variable 'rsds' would be the most appropriate choice for determining solar variability with a changing climate.

Table 2. List of Variables for used to determine resources uncertainty for solar, wind, and battery.

CMIP6 Variable	Renewable Resource	Description
sfcWind (m s^{-1}),	Wind power	Near-surface (usually, 10 meters) wind speed in Time, (Latitude, Longitude) (1 degree) (180, 360)
rsds (W m^{-2}),	Solar power	Surface Downwelling Shortwave Radiation in Time, (Latitude, Longitude) (1 degree) (180, 360)
Ts (K),	Battery storage	Surface Temperature in Time, (Latitude, Longitude) (1 degree) (180, 360)

Figure 2 shows the time-averaged global annual mean of the three simulations and the variables of interest, surface downwelling shortwave radiation, surface temperature, and near-surface wind power. These annual averages are shown to give a notional sense of the global variability and magnitudes of the three variables, showing differences in energy, temperature, and wind over New Mexico compared to other regions of the globe. Qualitatively, there is little spatial difference between the 'No Climate Change' and 'Low Climate Change' scenarios. The 'High Climate Change' scenario shows significant warming in the Arctic and in New Mexico. Wind speeds and surface downwelling shortwave radiation over New Mexico do not change as much as temperature across the three scenarios.

The time series trends for each of the variables for each of the simulation is shown in Figure 3. The simulation output is in the form of monthly means, and a 48-point running average was computed for each of the time series. Three area-weighted averages were computed for comparison: the entire globe, the contiguous United States (i.e., lower 48 States), and the State of New Mexico. In the 'No Climate Change' scenario, it is expected for there to be little-to-no-trend over the time series because the Earth system is in pre-industrial energy equilibrium. The 'Low Climate Change' scenario shows increasing surface temperatures in the latter portion of the simulation, which is consistent with observations and the basis upon which this simulation is designed. The trends in the surface downwelling shortwave radiation and near-surface wind speed also show minute changes in the end of the simulation. Impacts in the simulation of coarse spatial resolution and parameterizations, or not enough forcing to cause a discernable change in the time series are all probably causes for these two variables' trends. The 'High Climate Change' scenario shows the expected increase in surface temperature, a reduction in near-surface wind speed, and no discernable change in the surface downwelling shortwave radiation. There is little confidence in the trends of wind and radiation for this scenario, with more discussion given in Section 2.3.

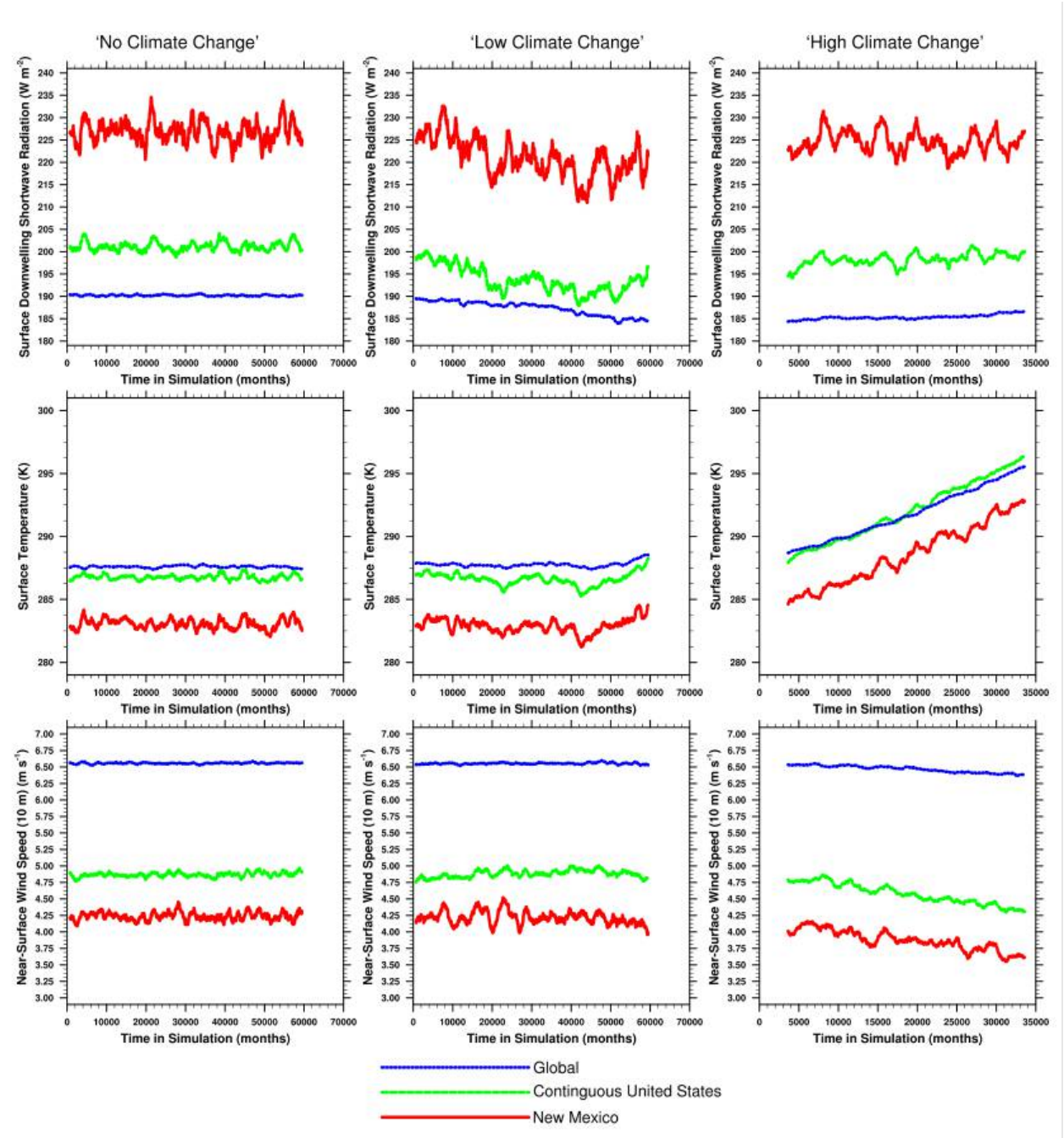


Figure 3. Time series of the surface downwelling shortwave radiation, surface temperature, and near-surface wind speed for the 'No Climate Change' (ECA_piControl), 'Low Climate Change' (historical), 'High Climate Change' (SSP585) CMIP6 E3SM simulations for global, contiguous United States, and New Mexico areas. The time series represents monthly means from the simulation data, and the data were smoothed by applying a 48-point running average.

2.2. Results and Discussion

Bounds and trends are needed for the solar and wind resource calculations. Because climate models are inherently uncertain in that they are and represent chaotic systems with much dependence on

initial conditions for solutions, it was decided to take averages of the three simulations over the state of New Mexico. New Mexico's land area is small compared to the global surface, and instances of the climate over New Mexico for any given month could be representative of the past, current, and future climate. Table 3 shows the time averages and standard deviations over New Mexico for the entire simulations for the three variables. Figure 4 shows the probability distribution functions for the time series averaged over New Mexico for each of the variables in each simulation scenario.

From Table 3, there is no trend in surface downwelling shortwave radiation (i.e., solar radiation) over the 'No', 'Low', and 'High climate change scenarios. The near-surface wind decreases slightly from 'No' to 'High' climate change scenarios, and the temperature increases by 5 K from 'No' to 'High' climate change.

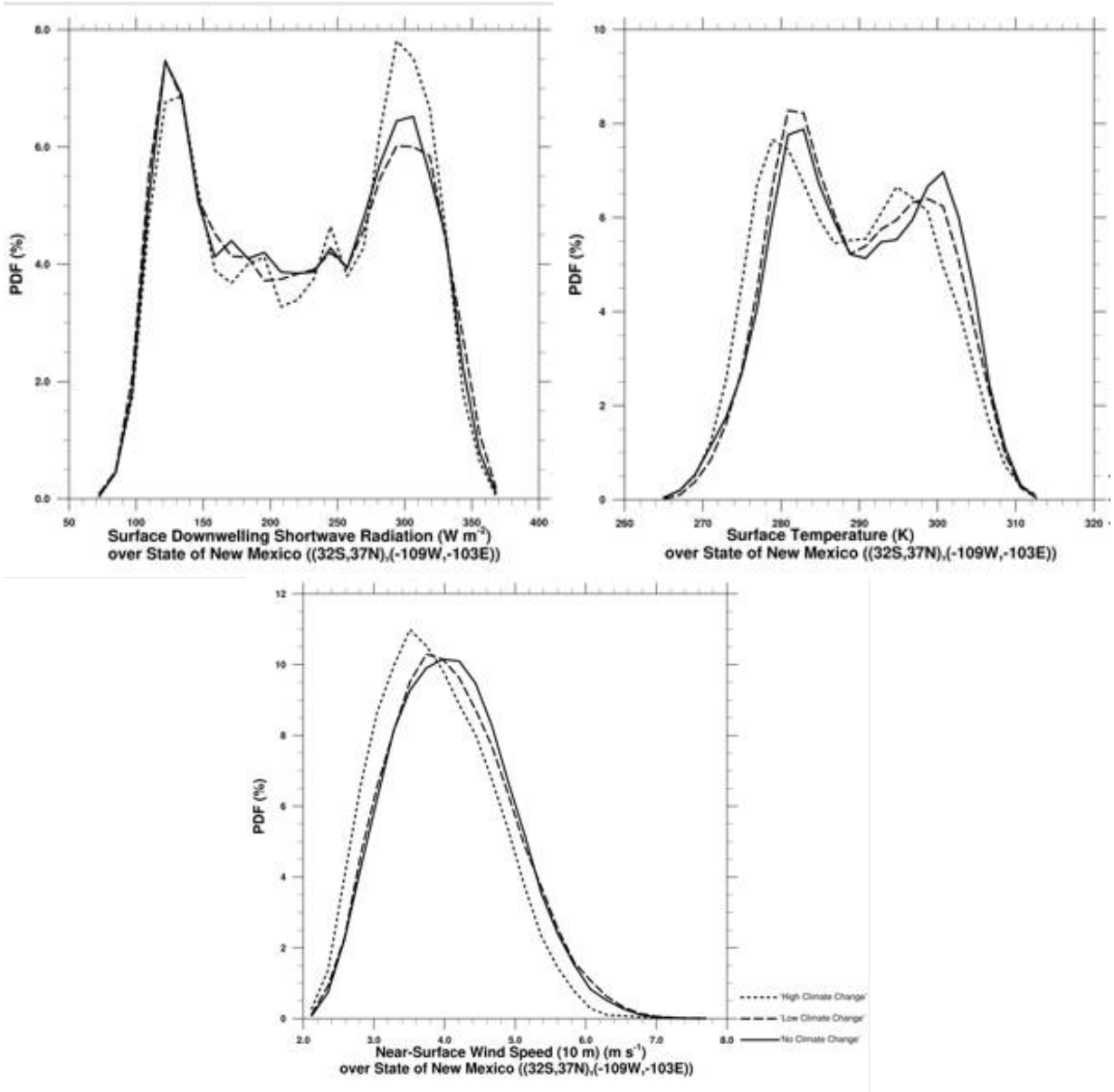


Figure 4. Probability Distribution Functions of the time-averaged and spatially-averaged (over New Mexico) of (top to bottom) surface downwelling shortwave radiation, surface temperature, and near-surface wind speed for the three simulations scenarios in the CMIP6 E3SM database.

Table 3. Averages and Standard Deviations of solar radiation, surface temperature, and surface wind from E3SM CMIP6 scenarios.

Variable	Scenario	Average	Standard Deviation
Solar, rsds (W m^{-2})	No climate change	226.7	75.21
	Low climate change	221.0	76.51
	High climate change	224.4	75.56
Surface Temperature, Ts (K)	No climate change	283.0	9.250
	Low climate change	283.1	9.244
	High climate change	288.5	9.613
Surface Wind, sfcWind (m s^{-1})	No climate change	4.239	0.7831
	Low climate change	4.215	0.8471
	High climate change	3.871	0.8012

2.3. Comparison with Other Studies

This study is not alone in assessing climate change impacts on renewable energy resources. Global, national, and regional bodies of research exist for specific technologies as well as system-level studies. For future reference, Solaun & Cerdá [6] provides global overviews of climate change effects on renewable resources. Additionally, a nationwide assessment of energy demand under different emissions scenarios stated that electricity demand will increase on average of 10%, which included power system generation with power system planning and operations [7]. In the literature review performed for this study, it was found that there is unanimous uncertainty in the magnitude and direction of energy resources being impacted regionally and under different future climate scenarios. The focus now narrows to literature that has the most direct application or comparison with this work, this section provides an overview of select literature reporting for the southwestern United States. For neighboring state Texas for solar and wind, wind increases by 1-4%, but there is no clear concurrence on solar production for future years 2041-2050 [8, 9].

Wind power, although very specific to region, show both an increase and decrease in potential wind energy production through the variability of wind speed projections over different seasons and emissions scenarios [8-10]. Often, a higher-resolved North American regional atmospheric model such as the NACORDEX (North American component of the international CORDEX (Coordinated Regional Downscaling Experiment) [11], or WRF (Weather Research and Forecasting model) [12] is used in these studies and compared with a courser resolution global model [13]. Recently there have been observations that winds, including surface winds, are slowing globally. A recent review paper suggests that the data supporting this claim might be region-specific, and more information about internal modes of climate and changes to land use, land cover is needed before understanding this theoretical trend [14]. The previous works considered for comparison here did not mention the observational trend of wind stillness in their findings.

For solar power, there appears to be no agreement that solar resources will increase or decrease for a given future, warmer climate across the western United States [10, 15-18]. Even comparisons using 37 Earth system models run under the CMIP5 protocols showed an increase in solar production for the southern United States. However, when 14 regional climate models (i.e., higher spatial

resolution) were used, the solar production was calculated to decrease [19]. Although unresolved cloud behavior seems to be a likely culprit in explaining the differences between the global and regional models, differences in cloud properties alone could not explain differences, so it was assumed aerosols were also playing a role with an approximately ± 2.5% change in solar radiation at the surface. However, it should be noted that aerosol concentrations and pathways contain high uncertainty and speculation in future climate projections.

For general climate model bias as it relates to observations, climate modelling groups publish simulated model bias compared to global observations. The climate model used in this work, E3SM, has reported a negative bias of shortwave (visible) cloud radiative effects compared to observations, but with little to no precipitation bias compared to global satellite observations. This could imply that E3SM rains-out the simulated cloud, leaving too-little cloud mass after a precipitation event. Additionally, E3SM has a strong aerosol-related effective radiative forcing and a high equilibrium climate sensitivity. This means the SSP585 scenario is likely to project a warmer Earth than other models at the end of the simulation in year 2100.

2.4. Next Steps

In gathering information needed to compute future climate change scenarios, a list was developed of potential future work that could analyze details of future climate change impacts to renewable energy production.

- Models that have high spatial and temporal resolution produce different trends than global models. Despite high variability and uncertainty, understanding the benefits of additional information at the cost of computer time is still undetermined for New Mexico [9]. Understanding downscaling for this problem is needed.
- In the CMIP6 database, the climate variable standards for solar radiation did not separate the Global Horizontal Irradiance (GHI), into the terms of Diffuse Horizontal Irradiance (DHI) and Direct Normal Irradiance (DNI), $GHI = DHI + DNI \cdot \cos(z)$. Understanding predictions and baseline results of diffuse and direct will help understand model bias in changes in aerosol optical depth and cloud cover.
- The results presented here are monthly means which do not account for nighttime and daytime differences with high time resolved datasets. For solar power production, nighttime values will be different than daytime, and wind production might also change over a diurnal cycle. Finding data in the CMIP6 archive or going to individual model output will clarify the computed answers and could change the uncertainty distribution.
- Wind turbines have cut-in and cut-out speeds. Higher time-resolved values for wind will show when wind speed is too great for turbines.
- Although this is not expected to change the findings of this report, using data from the CMIP6 archive that has more vertical levels, or altitude values, so that hub height and not sfcWind is used to calculate the wind power generation.
- Trends for wind slowing and stillness over New Mexico should be investigated in both observational data and simulated future climate projections.

- The E3SM baseline simulation (i.e., the pre-industrial control) should be compared to reanalysis and other weather-based datasets to improve the understanding of the baseline bias.
- Other studies have used field-acquired data with machine learning sorting algorithms to determine potential weather impacts on renewable energy production [20]. Given the difficultly of earth system models to simulate extremes, linking realistic data with future projections is an area of potential research.
- How can the unresolved clouds, and uncertainty in cloud cover be accounted for? Jiménez et al. [21] looked at 6-hour ensemble simulations with WRF Solar for unresolved cumulus with observations and found that parameterizing radiative effects of deep and shallow cumulus is necessary to reduce a 55% overprediction in GHI. A positive GHI bias has been reported in WRF over Albuquerque, New Mexico [12]. How can this cloud bias be accounted for in global earth system models?
- Other options for increasing resolution include using variable or refined resolution atmospheric models. These configurations could also be linked with Sun4Cast and weather prediction to compute solar variability [17]. Wang et al. [22] used CESM-VR with clustering for wind resources over California and found statistically significant changes in capacity. They found through clustering weather patterns that over a 36-year period, wind regimes occurring on "hot summer days increased at half a day per year and stagnant conditions increased at one-third days per year." Using downscaled MERRA with WRF and energy firm data helped drive this finding [23].

3. CLIMATE CHANGE IMPACTS ON SOLAR AND WIND POWER GENERATION

3.1. Wind and Solar Resources in New Mexico

Table 4 summarizes the existing wind resources in NM operated by PNM, and Table 5 summarizes the existing and pending solar resources in NM operated by PNM. The older wind turbines are at a hub height of 80 meters, and the newer ones are at 90 meters. PNM will likely add more wind in the future, but the timing and amount are uncertain. Additional wind capacity will probably also be in Torrance County (near Clines Corners) because of access to PNM transmission.

Table 4. Wind Resources in New Mexico.

Existing Wind PPA Resources	County	Net Capacity (MW)	Lat.	Lon.	Turbine Cap (MW)	Turbine Model	Hub Height (m)
NM Wind Energy Center	Quay	200	34.63	-104.05	1.5	GE1.5-87	80
Casa Mesa Wind	Quay	50	34.6	-103.99	2.5	GE2.5-127	89
La Joya 1	Torrance	166	34.62	-105.65	2.5	GE2.5-127	89
La Joya 2	Torrance	140	34.69	-105.34	2.5	GE2.5-127	89
Red Mesa Wind	Sandoval	102	35.26	-107.38	1.6	GE1.6-82.5	80

Table 5. List of PRC-approved and pending-approval large solar arrays in New Mexico.

	AC Capacity (MW)	Latitude	Longitude	Status
Arroyo	300	35.95462	-107.622	PRC-approved
Jicarilla 1	50	36.31675	-107.316	PRC-approved
San Juan	200	36.82913	-108.349	PRC-approved
Rockmont*	100	36.77774	-108.373	PRC-approved
Atrisco	300	35.2007	-106.933	Submitted Application
Jicarilla 2	50	36.238	-107.297	Submitted Application
Sky Ranch	190	34.76835	-106.791	Submitted Application
Encino North	50	35.35457	-106.856	Submitted Application

3.2. Impact of Modeled Climate Change on PNM Wind Power Generation

Using hourly 2012 wind speed data [24] for a point representing the NM Wind Energy Center wind generator (204 MW installed capacity), we found that that a drop of 8.7% in wind speed each hour yielded a *13% drop in total wind energy output* for the year. The following sections describe these findings.

3.2.1. Methodology

2012 wind speed data for a site representing the NM Wind Energy Center were obtained on an hourly basis from the Wind Prospector [24]. Specifically, wind speed data for the cell located at lat: 34.65, long -104.04 (Site ID: 874603 on the Wind Prospector [24]) was downloaded on an hourly basis for 2012.

Turbines are classified as Class I, II, or III depending on the average annual wind speed, as outlined in the International Electrotechnical Commission (IEC) 61400-1 standard [25]. See Table 6 for average wind speed design details for each class.

Table 6. IEC Wind Turbine Classes

Wind Turbine Class	Average Design Windspeed (m/s)
I (High wind)	10
II (Medium wind)	8.5
III (Low wind)	7.5

The wind power equation is as follows: Power = ½ ρ AV^3 Cp, where ρ = Density of Air in kg/m^3 (about 1.225 kg/m^3 at sea level), V = velocity in m, A = area swept by the wind turbine blades, and Cp = ratio of power extracted by wind turbine to total available in the wind resource, where 0.59 (the Betz Limit) is the theoretical maximum [26]. Because the kinetic energy available in wind is proportional to the cube of the wind velocity, a wind turbine experiencing 9 m/s winds is exposed to more than three times the force of a wind turbine experiencing 6 m/s winds. It would not be economical to design turbines for low-wind sites to the same standards as high-wind sites; therefore, different design standards were established for sites with different average levels of wind.

A wind speed-to-power conversion curve was then obtained for a Class II turbine [27]. This power curve is illustrated in Figure 5. As Class II turbines are the most common, the study team decided to calculate how changes in wind speed impact the power production of these turbines.

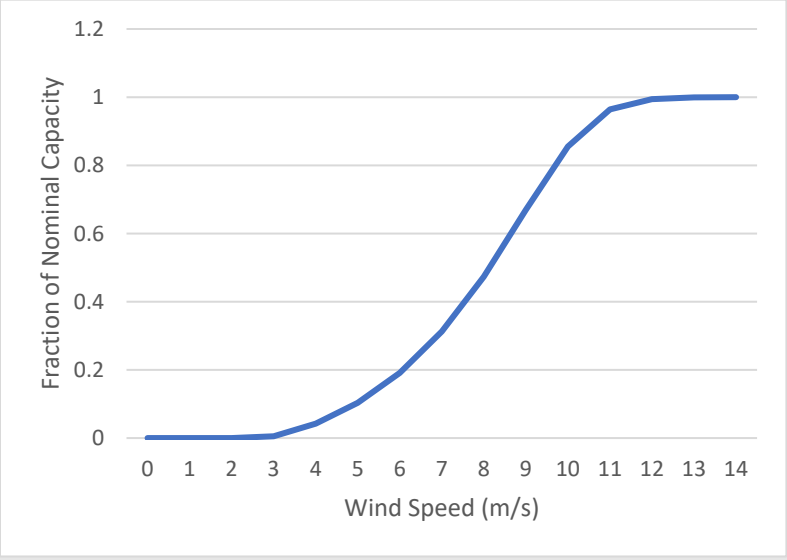


Figure 5. Power Curve for IEC Class II Turbine

Wind speed data were not obtained for each individual wind turbine – the simplifying assumption was made that since we are interested in the difference between generation at a reference wind speed and a post-climate change wind speed, it is reasonable to not take individual turbine locational differences into account.

The wind farm output in each hour was calculated using the Wind Prospector dataset for 2012 as input to the power curve in Figure 5. Since this data is for wind at 100 meters, and the NM Wind Energy Center's turbines are at a hub height of 80 meters, the wind speed data was adjusted downwards by about 3.1% in each hour to reflect the lower wind speed at this height using a wind power-law model [28].[2] Next, the resulting 80 meter wind velocity was reduced in each hour by 8.7% to reflect the modeled change in the High Climate Change scenario. The wind farm power output in that scenario in each hour was then computed.

Comparing the total amount of power generated in the reference case to the High Climate Change scenario, the study team found that the 8.7% drop in wind speed in each hour led to *an overall 13% drop in wind generation output.*

The annual capacity factor calculated for the wind farm (using a single-point representation of that wind farm) was calculated at 47.7% for the reference case, and 41.2% for the High Climate Change scenario. 47.7% is an unusually high capacity factor for a wind farm and suggests that more detailed modeling may be warranted. Nevertheless, we are more interested in the difference between the two scenarios. It is reasonable that the percentage decline in power generation should be greater than the percentage decline in wind speed.

An 8.7% reduction in wind speed in each hour does not yield an 8.7% reduction in power output because the wind speed to MW output conversion formula isn't linear. With an 8.7% drop in wind speed, the number of hours the wind speed is above 11 m/s (94.6% of full power output or greater) drops from 20.1% to 13.6% of all hours in the year. The number of hours the wind speed is 4 m/s (4.2% of full power output or less) increases from 13.6% to 16.7% of all hours in the year. In addition, the slope in the middle of the curve is quite steep – going from 7 m/s to 8 m/s causes output to increase by about 50% (from 31 MW to 47 MW for a 100-MW wind farm). An 8.7% reduction in wind speed along this section of the curve will yield a drop in power output much greater than 8.7%.

3.3. Impact of Modeled Climate Change on PNM Solar Power Generation

The potential impact of climate change on PNM solar power generation was modeled using two different methods. One method (called the "Specific" method) involved calculating the output for the Arroyo solar plant given 5-minute satellite weather data, and then adjusting the solar irradiance and increasing the ambient temperature by the climate-change-scenario amounts. Another method (called the "General" method) focused on calculating the impact of climate change on a generic solar PV facility.

The two methods arrived at the same conclusion – a 2.5% drop in solar irradiance and a 5.5 °C rise in ambient temperature (in all hours) would result in roughly a *4% drop in solar PV generation.* Based on results from the Specific method, about half of this drop is due to the decrease in solar irradiance, and about half is due to PV efficiency loss from higher ambient temperatures.

3.3.1. Climate Scenario Selection

Based on the climate modeling results given in Table 3, we see that a simulated worst-case scenario for solar PV power production would be a 2.5% drop in solar irradiance (with solar irradiance dropping from 226.7 W/m^2 in the reference case to 221.0 W/m^2 in the "Low Climate Change"

[2] The formula is: $U = U_r (Z / Z_r)^{\alpha}$, where U is the wind speed at height Z, Ur is the known wind at the reference height Zr, and $\alpha = 0.143$ in neutral stability conditions (over land). The result is that we need to multiply the 100m wind dataset by a factor of 0.9686 to adjust for the 20m lower height of the turbines at the NM Wind Energy Center.

case), and a 5.5 °C increase in average ambient temperature (10 °C average in the reference case to 15.5 °C in the "High Climate Change" case). A great deal of uncertainty exists in these preliminary climate models, and it is possible that actual climate change impacts may be less or greater than our simulated "worst-case." Our primary goal was to develop a methodology and framework that can be used for future analyses with more refined climate models and data.

3.3.2. Methodology – Specific Method

A single, large solar PV plant was modeled using **pvlib python**, which is a community-supported tool that allows for detailed simulation of the performance of photovoltaic energy systems [29]. It was originally ported over from the PVLIB MATLAB toolbox developed at Sandia National Laboratories and implements many of the models and methods developed there.

The location chosen for the plant was the site of the future Arroyo solar PV power plant (in McKinley County, NM – about 10 miles East of the Chaco Culture National Historical Park). Given that this plant is the largest plant approved by the NM PRC to date, and that it is a single-axis tracking plant (as all future PV plants for PNM are likely to be), the study team felt that this plant is sufficiently representative of the PV plants that will make up most of PNM's solar PV plant capacity in the future that it can be used as a proxy for PNM solar PV plants in general.

Solar irradiance (and ambient temperature) data was downloaded from the National Solar Radiation Database (NSRDB) [30] at a five-minute resolution for the cell with coordinates latitude: 35.96°, longitude: -107.63°. This cell represents an area of 4 km^2 (as the spatial resolution is 2 km by 2 km). The NSRDB identifier for this cell is: 787961.

The solar irradiation data used in this model, specifically, are Diffuse Horizonal Irradiance (DHI), Direct Normal Irradiance (DNI), and Ground Horizontal Irradiance (GHI). The units for these measurements are in watts per square meter (W/m^2). DHI is the amount of radiation received per square meter by a surface (not subject to any shade) that does not arrive on a direct path from the sun (in other words, light that's been scattered by molecules in the atmosphere). DNI is the solar radiation per square meter by a surface that is always perpendicular to the light coming straight from the sun (given its current position in the sky). GHI is the total amount of shortwave radiation received from above by a surface horizontal to the ground. The relationship between these three measurements of solar irradiation is given by:

$GHI = DNI * \cos(\theta) + DHI$, where θ is the solar zenith angle (directly overhead would be $\theta = 0$) (PV Performance Modelling Collaborative, 2021)

The PV system simulated in **pvlib python** was assumed to be a single-axis tracking plant with an inverter load ratio (ILR) of 1.3. In other words, the PV panel capacity for this plant was set at 1.3 times the capacity of the AC inverter. The actual Arroyo plant will, in fact, have an ILR of 1.3, and it is likely that future solar PV plants providing power will have a similar ILR. This is because it is not economical to size the inverter at the full output capacity of the PV panels, as this full capacity would be used only for a small fraction of time. In addition, setting the inverter at a smaller size than the PV panels allows for a more even power output profile in the middle of the day. When PV panel production is greater than the inverter can accept, cloud cover that reduces PV panel production down to the inverter's capacity has no impact on the actual AC power production from the plant.

The system size chosen was a normalized 1.3MW DC, 1MW AC system. First, the reference case was generated by loading in the five-minute solar irradiance and ambient temperature data for 2018 and running the model. The model run generated an AC power output dataset for a year (at a five-minute resolution) based on the plant type, location, and solar irradiance /ambient temperature data given.

Next, the climate change cases were generated by modifying the weather inputs to account for a Low Climate Change scenario, a High Climate Change scenario, and a Combination scenario. Specifically, GHI, DHI and DNI were reduced at all times by the amount specified in each scenario, and the temperature was increased at all times by the average ambient change specified. New model runs were made which took this modified weather data as input and produced new AC power output datasets for a year (also at a five-minute resolution). The power output for each scenario run was summed over the year, and the total annual power generated was compared with the reference run. The changes used for these scenarios, as well as the results of the model runs, are given in Table 7.

Table 7. Solar PV Scenarios and Results.

Scenario	*Change in Solar Irradiation*	*Change in Average Ambient Temperature*	**Annual Drop in Solar Output**
Low Climate Change	-2.5%	0° C	***1.9%***
High Climate Change	-1%	+5.5° C	***2.9%***
Combination	-2.5%	+5.5° C	***4.1%***

The Combination scenario, which posits a 2.5% drop in solar irradiation and a 5.5 °C rise in ambient temperature, led to roughly a 4% decrease in solar PV power production as compared to the reference run.

3.3.3. Methodology – General Method

In this method, the cell temperature (Tcell) is calculated based on the insolation (S), the ambient temperature (Tamb) and the normal operating cell temperature (NOCT) that is measured at 800 W/m^2 and 20 °C ambient as following:

$$Tcell = Tamb + (NOCT-20)*S/800\ °C$$

Therefore, given ambient temperature and insolation differences, the cell temperature change can be calculated as following:

$$\Delta Tcell = \Delta Tamb + (NOCT-20)*\Delta S/800\ °C$$

Since power-temperature coefficient (Cp - %/degree C) of a PV panel is often given based on testing data, the percentage change in output generation of the PV panels can be specified:

$$\Delta Pout = Cp*\Delta Tcell,\ \%$$

Given 5.5 °C ambient temperature rise, around 2.5 % insolation reduction and -0.3% power-temperature coefficient, the overall reduction in annual generation of PV system is calculated and compared with the baseline case. The results show that PV generation drops about 4%.

This Page Left Blank

4. CLIMATE CHANGE IMPACTS ON BATTERY STORAGE

Operating temperature is one of the main factors that significantly affect the life span as well as the performance of li-ion batteries (LiB). While high temperature increases the formation and modification of the surface film on batteries' electrodes making them degrade faster, low temperature slows down the electrochemical reactions within the batteries making them less efficient. Furthermore, extremely low or high temperature can also create serious damage to LiBs. Therefore, for grid-scale battery energy storage systems (BESS), heating, venting and air conditioning (HVAC) systems are often required to maintain the battery enclosure's temperature within an operating range. Since the change in ambient temperature will impact HVAC's operation, it will also impact the overall performance of a BESS.

4.1. Impact of Temperature Change on Battery Storage

In this section, the impact of climate change is seen as the impact of ambient temperature rise on the performance and degradation of Li-ion BESS. Three scenarios of temperature rise are considered including:

- Scenario 1 - Nominal: this scenario assumes the ambient temperature would not change in the next 24 years. This is used as the baseline to evaluate the other two scenarios.
- Scenario 2 - Moderate temperature rise: this scenario considers 2-degree temperature rise in the next 24 years.
- Scenario 3: Extreme temperature rise: this scenario considers 5-degree temperature rise in the next 24 years.

Grid-scale Li-ion BESSs are required to sit outdoors by the current safety codes. Therefore, these BESSs are often packed as modules that are contained in standard shipping containers. The module size often varies with applications and manufacturers; however, in this work we model a typical 1MW/4MWh module contained within a 20-ft standardized shipping container. Just as modules can be stacked to achieve a larger system, so too this model can be scaled to model the systems of different sizes. The purpose of this model is to study the overall performance of BESS given the ambient temperature and the loading (charge/discharge) profile of the BESS. For simplification, the following assumptions are made:

- BESS alternatively charges and discharges every 12 hours
- BESS loss is purely heat loss
- Battery temperature is equal to the enclosure temperature
- The container is not insulated

The input parameters of the model are given in Table 8.

Table 8. Parameters used in HVAC modeling of BESS power consumption.

Parameters	Unit	Value
BESS Power Rating	MW	1
BESS Energy Capacity	MWh	4

Parameters	Unit	Value
LiB Specific Weight	Wh/kg	160
Mass, m	kg	25000
Round-trip Efficiency	%	90
One-way Efficiency	%	95
BESS Specific heat, c_p	J/kg.K	1000
HVAC Capacity	BTU/hr	80,000 (23,400 W)
Container Surface Area	m^2	67.63
Container Emissivity	-	0.8
HVAC Power Rating	W	8000
HVAC Duty Cycle	%	40
HVAC Max Coefficient of Performance	-	4

The container's change in temperature, ΔT (K), at each time step, *i,* is calculated using an energy balance:

$$\Delta T_i = \frac{\dot{E}_{in,i} - \dot{E}_{out,i}}{mc_p} \Delta t \quad (1)$$

where $\dot{E}_{in,i}$ is the heat generation (W) caused by the battery inefficiency (assumed to be lost entirely to resistive heating) during charging and discharging, $\dot{E}_{out,i}$ is the heat dissipation from radiation and conduction from the shipping container and convection via HVAC, m is the mass of the BESS and container (kg), c_p is the specific heat (J/kg-K), and Δt = 1 hr (3600 s). In the model, the HVAC is on at its rated power if the container's temperature is above 45 °C, off if the temperature is below 25 °C, and holding its status (on or off) if the temperature is decreasing below 45 °C or increasing above 25 °C. In each scenario, the model is used to simulate the container temperature at each hour throughout a year. The HVAC's energy consumption for a 4 MWh BESS is calculated accordingly and compared between different scenarios. The results are shown in Table 9.

Table 9. Modeled annual HVAC energy consumption as a function of ambient temperature rise.

Climate Scenario (ambient temperature)	HVAC Annual Energy Consumption (MWh)	HVAC Annual Energy Consumption Change (%)	Ratio (%) of HVAC Annual Energy Consumption to Annual Battery Throughput Energy[1]
Current conditions	23.5	0	1.6%
2 °C increase	25.0	12.1%	1.7%
5 °C increase	27.3	22.4%	1.9%

[1]Four MWh/discharge x 365 discharges/yr = 1,460 MWh of annual battery throughput energy

As seen in Table 9, the HVAC annual energy consumption increases as the temperature rises. This is because ambient temperature rise will reduce the heat dissipation through radiation, convection, and conduction making the HVAC work harder to maintain the operating temperature range. Significant increase in HVAC energy consumption will increase the overall load of the system thereby decreasing the net impact of BESSs. However, the relative impact of an ambient temperature rise of up to ~5 °C on increased HVAC energy consumption is predicted to yield less than 1% change in the total annual battery throughput energy. Therefore, the uncertainty on increased temperatures on HVAC parasitic power consumption is not directly included in the probabilistic simulations; the uncertainty is assumed to be subsumed by the uncertainty in the capacity fade and round-trip efficiency described in the next section.

4.2. Impacts of Capacity Fade and Round-Trip Efficiency on Battery Storage

Capacity fade and round-trip efficiency can impact the available throughput energy of battery storage systems. Although not necessarily tied to climate change, this study included uncertainty in capacity fade and round-trip efficiency in the probabilistic simulations.

Capacity fade is a condition in which the total energy capacity that a battery can deliver reduces with use and is dependent on a number of factors including ambient temperature, discharge rate, and depth of discharge. Preger et al. [31] performed a multi-year test of different lithium-ion cells under varying discharge conditions and found that the number of cycles to reach an 80% capacity (20% capacity loss) ranged from only a few hundred cycles to several thousand cycles, depending on cell type and conditions. Spotnitz [32] reported that among different lithium-ion cell types, the capacity loss at 500 cycles ranged from ~12 – 24%. Based on these studies, we assume that the capacity loss of battery storage systems used by PNM may be up to 20% within a few years of deployment – before issues are identified and servicing or replacement of cells can be performed. A uniform distribution for battery capacity fade between 0 – 20% was therefore assumed and sampled for each annual realization of the hourly energy balance. This sampled value was used to reduce the total battery storage capacity prescribed in the 2040 No New Combustion scenario.

Preger et al. also evaluated the round-trip efficiency (energy out/energy in) of various lithium-ion cells and found that the initial round-trip efficiency varied between ~80% - 95%. After cycling to a capacity loss of 20%, the decrease in initial round-trip efficiency ranged from less than a few percent up to ~10% in many reported cases. Based on these studies, the round-trip efficiency (and impacts of potential degradation) for the battery systems used by PNM during any year in the probabilistic simulations was assumed to be uniformly distributed between 80 - 95%. The sampled round-trip efficiency was used to reduce amounts of energy added to the battery during any hour when supply

exceeded demand for the No New Combustion scenario. For example, if the sampled round-trip efficiency for a given year was 90%, and the energy supply exceeded demand by 10 MWh during a given hour, the energy stored during that hour for later delivery was set equal to 0.9 x 10 MWh = 9 MWh (assuming that the total energy stored did not exceed the total nameplate capacity of all available battery storage systems, accounting for capacity fade described above).

4.3. Implementation into QuEST

QuESt is an open-source software application suite for energy storage evaluation. The latest version of QuESt includes two main applications 1) Market and 2) Behind-the-meter that are for evaluating the potential revenue of energy storage systems (ESS) providing grid and customer services. Currently, QuESt uses a linear energy flow model of an ESS that only considers round-trip loss while cycling the storage device. In other words, it ignores the impact of HVAC consumption on system performance. Therefore, the revenues produced by these applications can be much higher than they are when significant amount of energy is discounted for running the HVAC to maintain the operating temperature range.

To improve QuESt in the future, the above thermal model and uncertainties in capacity fade and round-trip efficiency can be incorporated to better capture the impact of HVAC and degradation on ESS's operation. Another way to improve QuESt is co-simulating the electrical charge/discharge behaviors of an ESS with its thermal behaviors. While the above thermal model can be used for standard shipping containers, a more sophisticated package like Energy Plus will provide more accurate results for different types of enclosures. Once the ESS model is successfully updated with a thermal model/simulation, an optimization process needs to be developed to find the optimal charge/discharge profile for an ESS given different climate patterns. The results will better inform the decision on siting and sizing ESS for a particular application given a weather pattern. The incorporation of the above model or co-simulation can be difficult as they will require QuESt to solve a non-linear problem that can be intractable.

5. PROBABILISTIC ANALYSIS OF CLIMATE CHANGE IMPACTS AND BATTERY PERFORMANCE

5.1. Modeling Approach

At each hour of the year starting at 12 AM January 1 and ending at midnight December 31, the energy, E_i (MWh), produced from all available generation sources in the 2040 No New Combustion scenario were summed, including uncertainty in intermittent wind and solar resources as impacted by climate-change modeling. In addition to variable solar and wind generation at each hour of the year, firm fixed resources (i.e., nuclear, geothermal) were added as prescribed by PNM (see Table 10). If the total generation exceeded the total load, L_i (MWh), at any hour, surplus generation was added to the battery storage (after adjustment for round-trip efficiency). If the generation was less than the load at that hour, energy was taken from battery storage. Checks were implemented to determine the minimum and maximum state of charge (SOC) of the battery storage system (in MWh) at each hour: (1) if generation was less than the load, and total SOC decreased to a value less than zero, the SOC was set to zero, and (2) if generation was greater than the load, and SOC increased to a value greater than the maximum battery storage capacity adjusted for capacity fade (*Fade*), the SOC was set equal to the maximum battery storage adjusted for capacity fade and battery round-trip efficiency (*RTE*). The SOC at the start of the year was assumed to be equal to 100%. The steps to calculate the SOC at each hour can therefore be summarized as follows:

$$SOC_i = SOC_{i-1} + \sum_i E_i - L_i \tag{2}$$

$$\begin{aligned}
&If\ SOC_i < 0,\ SOC_i = 0 \\
&elseif\ SOC_i > SOC_{\max}(1 - Fade_j),\ SOC_i = SOC_{\max}(1 - Fade_j)RTE_j \\
&elseif\ \sum_i E_i - L_i > 0,\ SOC_i = SOC_{i-1} + \left(\sum_i E_i - L_i\right) RTE_j
\end{aligned}$$

where i is the hour of the year (1 to 8760) and j is the realization (1 to 100).

Table 10. Summary of firm fixed resources assumed for PNM 2040 No New Combustion scenario (in addition to solar and wind generation) [1].

Parameter	Value
Total energy efficiency* (MW):	95
Total demand response* (MW):	15
Total coal resources (MW):	0
Total nuclear resources (MW):	288
Total natural gas resources (MW):	0
Total geothermal resources (MW):	11
Total battery storage resource (MWh):	14,328
% battery capacity on Jan. 1 (hour 1):	100%

*Not used in probabilistic hourly energy balance.

Uncertainty distributions of wind and solar generation, battery RTE, and battery fade (Table 11) were sampled to create 100 realizations of annual energy balances for the 2040 No New Combustion scenario. Figure 6 plots the cumulative distribution functions for each of these four

stochastic parameters used in the model. All other input parameters (e.g., firm fixed resources, load) were not varied from the baseline values.

In each realization, the loss of load expectation (LOLE) was determined as the number of days (hours divided by 24) in which the SOC was equal to zero during the year. The cumulative distribution function for the LOLE was plotted for all 100 realizations. The goal was to determine if the distribution of LOLE was significantly greater than the desired value of 0.2 days/year or less with the impacts of climate change and uncertainty in battery performance. If so, a sensitivity study would be performed to determine the additional battery storage capacity required to reduce the LOLE to 0.2 days/year or less.

Table 11. Summary of uncertainty distributions in probabilistic simulations.

Parameter	Nominal Value*	Uniform Distribution	
		Minimum	Maximum
Wind generation (MWh)	-13%	-50%	+50%
Solar generation (MWh)	-4%	-50%	+50%
Battery RTE	N/A	80%	95%
Battery capacity fade	N/A	0%	10%

*The nominal value for wind and solar generation represents the impact of climate change (see Sections 3.2 and 3.3) on baseline values provided by PNM using their historical capacity factors and expected generation capacity in the 2040 No New Combustion portfolio (see Sections 5.1.1 and 5.1.2).

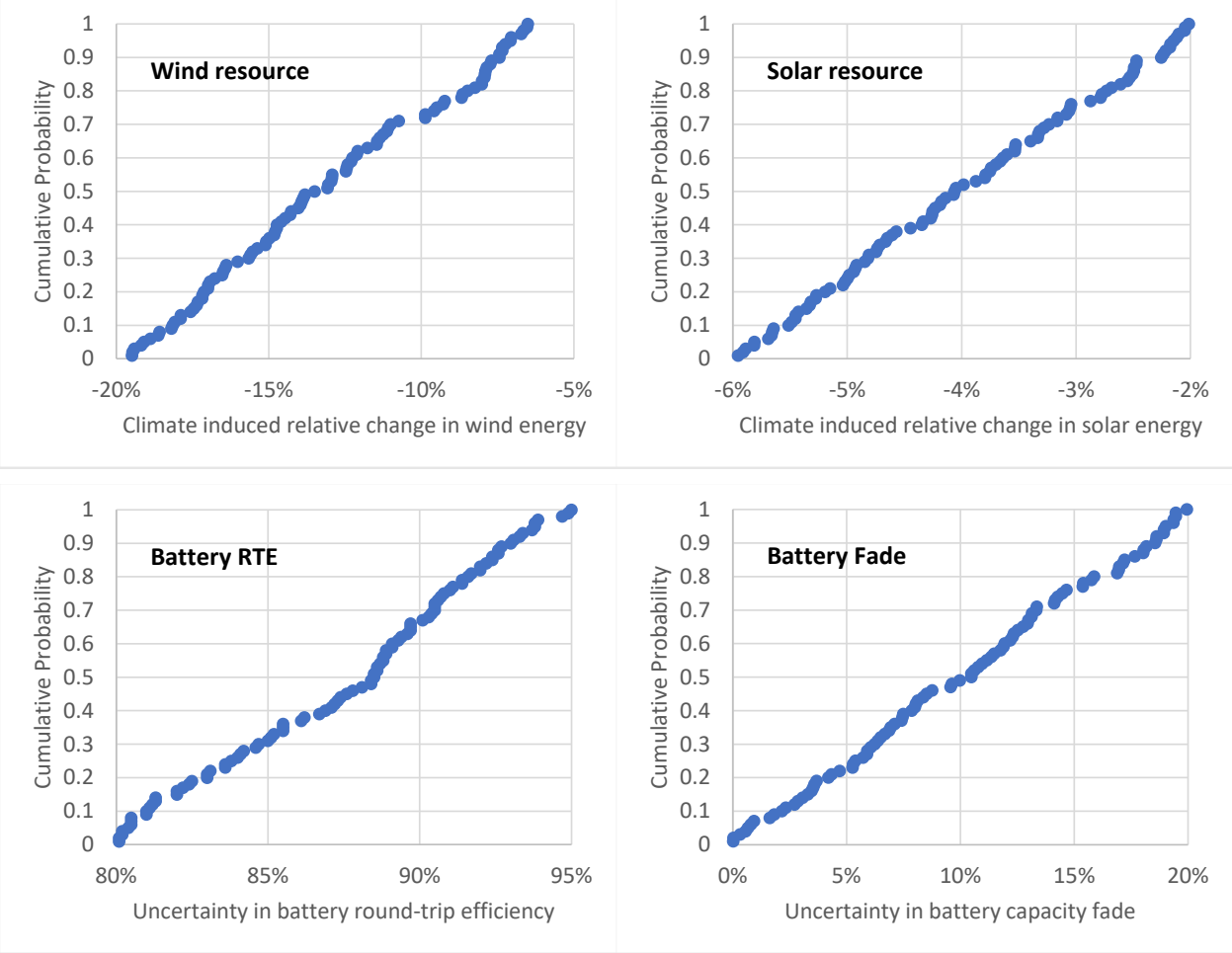


Figure 6. Cumulative distribution functions of climate-induced changes in wind and solar resources (top) and uncertainty in battery performance (RTE and capacity fade; bottom).

5.1.1. Uncertainty in Wind Energy Resources

Historical average wind-generation capacity factors for each hour of the month were reported by PNM (2013 – 2019) [1] as shown in Table 12. Figure 7 plots these hourly wind-generation capacity factors by month, which reveals that wind generation typically peaks in the late afternoon and evening hours and subsides in the morning hours. Februrary through April are the most productive months for wind generation, while July and August are the least productive.

These hourly capacity factors were multiplied by the total expected wind generation capacity in the 2040 most cost-effective No New Combustion portfolio presented in the PNM 2020 – 2040 IRP [1] to yield baseline wind power generation values at each hour of the year (Table 13). For simplicity, the wind generation for a specific hour of any given month was assumed to be the same (e.g., the wind generation at 7 AM for each day in January was assumed to be the same; the wind generation at 3 PM for each day in July was assumed to be the same).

Uncertainty in these baseline values was accommodated by uniformly varying the baseline values by up to ±50% in the probabilistic simulations as summarized in Table 11. Although arbitrary, this uncertainty range was thought to be appropriate to accommodate uncertainty in not only the natural

variability in wind generation but also the unceratinty in the preliminary climate models. A sensitivity was also performed to determine the impacts of varying the uncertainty range on LOLE.

Table 12. Historical average capacity factors for PNM wind energy resources (2013 – 2019) [1].

	Hour																							
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	33%	32%	33%	33%	32%	32%	32%	31%	29%	28%	28%	30%	31%	32%	33%	34%	34%	35%	37%	39%	38%	38%	36%	35%
2	39%	38%	38%	36%	35%	35%	33%	31%	27%	28%	29%	32%	35%	39%	41%	42%	43%	41%	41%	41%	42%	41%	41%	39%
3	38%	36%	34%	33%	33%	32%	29%	26%	27%	28%	29%	30%	33%	35%	36%	39%	41%	41%	40%	41%	41%	41%	40%	40%
4	38%	37%	36%	34%	32%	30%	28%	26%	27%	27%	29%	32%	35%	37%	39%	42%	44%	43%	40%	42%	45%	44%	44%	40%
5	34%	32%	31%	29%	25%	22%	19%	19%	19%	20%	22%	25%	27%	31%	34%	35%	36%	38%	36%	36%	38%	39%	39%	37%
6	33%	31%	28%	25%	24%	21%	17%	16%	14%	14%	14%	15%	17%	20%	21%	24%	25%	27%	28%	29%	33%	34%	34%	36%
7	24%	22%	21%	20%	19%	17%	14%	12%	12%	11%	10%	10%	11%	12%	14%	17%	20%	21%	24%	25%	27%	27%	26%	24%
8	21%	19%	19%	19%	18%	16%	13%	11%	10%	10%	10%	9%	10%	12%	13%	16%	19%	21%	21%	22%	24%	25%	24%	23%
9	23%	21%	20%	18%	17%	17%	16%	14%	14%	14%	15%	16%	17%	19%	21%	24%	24%	23%	24%	28%	30%	29%	28%	26%
10	29%	28%	27%	27%	25%	25%	25%	22%	21%	23%	24%	26%	28%	30%	31%	33%	33%	32%	33%	35%	35%	34%	32%	31%
11	34%	33%	32%	31%	30%	30%	30%	29%	27%	28%	30%	31%	34%	35%	37%	37%	35%	34%	36%	37%	38%	37%	36%	34%
12	33%	32%	32%	31%	31%	31%	30%	30%	27%	26%	26%	27%	29%	31%	33%	33%	31%	33%	36%	36%	35%	35%	34%	33%

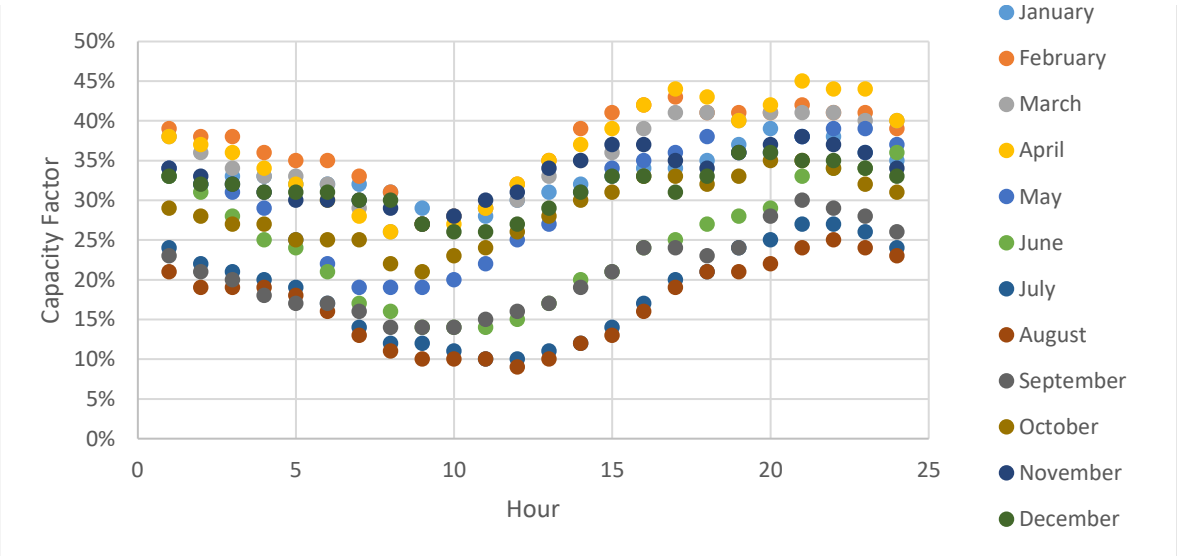


Figure 7. Plot of historical average capacity factors for PNM wind energy resources by hour and month (2013 – 2019) [1].

Table 13. Hourly baseline wind generation (MW) based on capacity factors in Table 12 and total prescribed wind generation capacity of 956 MW in the PNM IRP 2040 No New Combustion portfolio [1].

	Hour																							
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	315	306	315	315	306	306	306	296	277	268	268	287	296	306	315	325	325	335	354	373	363	363	344	335
2	373	363	363	344	335	335	315	296	258	268	277	306	335	373	392	402	411	392	392	392	402	392	392	373
3	363	344	325	315	315	306	277	249	258	268	277	287	315	335	344	373	392	392	382	392	392	392	382	382
4	363	354	344	325	306	287	268	249	258	258	277	306	335	354	373	402	421	411	382	402	430	421	421	382
5	325	306	296	277	239	210	182	182	182	191	210	239	258	296	325	335	344	363	344	344	363	373	373	354
6	315	296	268	239	229	201	163	153	134	134	134	143	163	191	201	229	239	258	268	277	315	325	325	344
7	229	210	201	191	182	163	134	115	115	105	96	96	105	115	134	163	191	201	229	239	258	258	249	229
8	201	182	182	182	172	153	124	105	96	96	96	86	96	115	124	153	182	201	201	210	229	239	229	220
9	220	201	191	172	163	163	153	134	134	134	143	153	163	182	201	229	229	220	229	268	287	277	268	249
10	277	268	258	258	239	239	239	210	201	220	229	249	268	287	296	315	315	306	315	335	335	325	306	296
11	325	315	306	296	287	287	287	277	258	268	287	296	325	335	354	354	335	325	344	354	363	354	344	325
12	315	306	306	296	296	296	287	287	258	249	249	258	277	296	315	315	296	315	344	344	335	335	325	315

5.1.2. Uncertainty in Solar Energy Resources

Historical average solar-generation capacity factors for each hour of the month were reported by PNM (2013 – 2019) [1] as shown in Table 14. Figure 8 plots these hourly solar-generation capacity factors by month, which shows that solar generation peaks around the 12th hour of the day (standard time) and is highest during the spring/summer months and is lowest during the winter months.

These hourly capacity factors were multiplied by the total expected solar generation capacity in the 2040 most cost-effective No New Combustion portfolio presented in the PNM 2020 – 2040 IRP [1] to yield baseline solar power generation values at each hour of the year (Table 15). For simplicity, the solar generation for a specific hour of any given month was assumed to be the same (e.g., the solar generation at 3 PM for each day in July was assumed to be the same).

Uncertainty in these baseline values was accommodated by uniformly varying the baseline values by up to ±50% in the probabilistic simulations as summarized in Table 11. Although arbitrary, this uncertainty range was thought to be appropriate to accommodate uncertainty in not only the natural variability in solar generation but also the unceratinty in the preliminary climate models. A sensitivity was also performed to determine the impacts of varying the uncertainty range on LOLE.

Table 14. Historical average capacity factors for PNM solar energy resources (2013 – 2019) [1].

	Hour																							
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%	0%	0%	0%	0%	2%	32%	57%	69%	74%	75%	70%	62%	46%	16%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	12%	45%	67%	77%	80%	79%	78%	71%	57%	33%	3%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	2%	29%	58%	75%	83%	84%	83%	81%	73%	61%	41%	11%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	14%	46%	64%	78%	85%	86%	85%	81%	74%	61%	44%	18%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	3%	26%	53%	68%	81%	87%	87%	86%	82%	74%	61%	46%	24%	3%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	4%	28%	52%	67%	81%	88%	89%	86%	81%	72%	60%	46%	26%	5%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	2%	22%	48%	65%	78%	85%	86%	83%	77%	68%	55%	40%	22%	4%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	14%	44%	62%	76%	84%	85%	82%	78%	68%	54%	38%	17%	1%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	8%	41%	61%	75%	83%	84%	82%	79%	69%	55%	35%	8%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	2%	33%	59%	73%	80%	80%	79%	75%	67%	51%	22%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	16%	47%	63%	70%	72%	71%	68%	59%	40%	8%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	4%	33%	56%	65%	69%	69%	66%	57%	36%	6%	0%	0%	0%	0%	0%	0%	0%

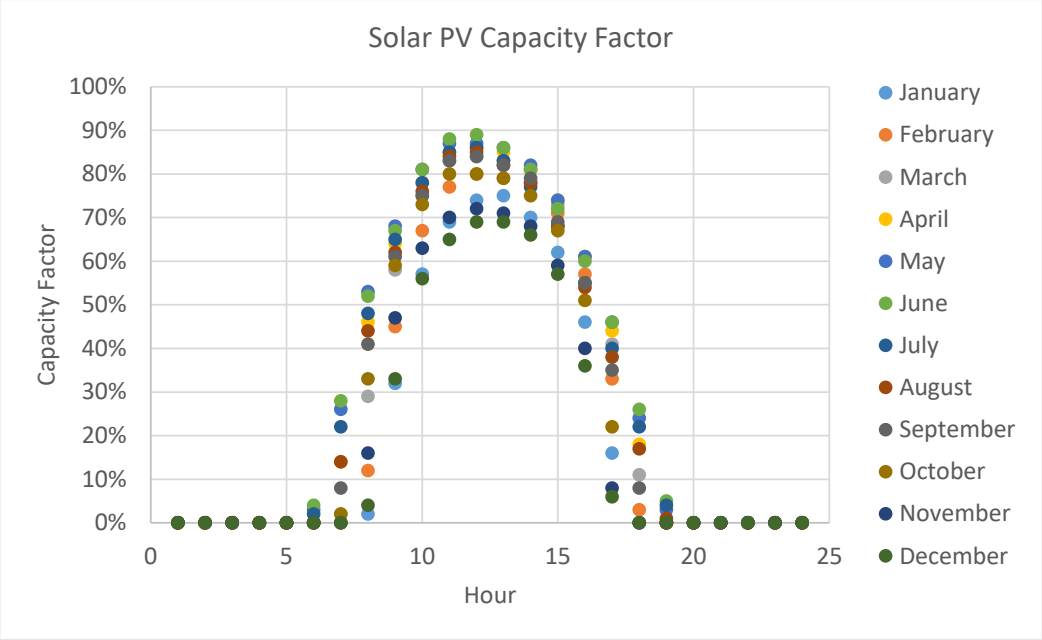


Figure 8. Plot of historical average capacity factors for PNM solar energy resources by hour and month (2013 – 2019) [1].

Table 15. Hourly baseline solar generation (MW) based on capacity factors in Table 14 and total prescribed solar generation capacity of 3,165 MW in the PNM IRP 2040 No New Combustion portfolio [1].

	Hour																							
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	0	0	0	0	63	1013	1804	2184	2342	2374	2216	1962	1456	506	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	380	1424	2121	2437	2532	2500	2469	2247	1804	1044	95	0	0	0	0	0	0
3	0	0	0	0	0	0	63	918	1836	2374	2627	2659	2627	2564	2310	1931	1298	348	0	0	0	0	0	0
4	0	0	0	0	0	0	443	1456	2026	2469	2690	2722	2690	2564	2342	1931	1393	570	0	0	0	0	0	0
5	0	0	0	0	0	95	823	1677	2152	2564	2754	2754	2722	2595	2342	1931	1456	760	95	0	0	0	0	0
6	0	0	0	0	0	127	886	1646	2121	2564	2785	2817	2722	2564	2279	1899	1456	823	158	0	0	0	0	0
7	0	0	0	0	0	63	696	1519	2057	2469	2690	2722	2627	2437	2152	1741	1266	696	127	0	0	0	0	0
8	0	0	0	0	0	0	443	1393	1962	2405	2659	2690	2595	2469	2152	1709	1203	538	32	0	0	0	0	0
9	0	0	0	0	0	0	253	1298	1931	2374	2627	2659	2595	2500	2184	1741	1108	253	0	0	0	0	0	0
10	0	0	0	0	0	0	63	1044	1867	2310	2532	2532	2500	2374	2121	1614	696	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	506	1488	1994	2216	2279	2247	2152	1867	1266	253	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	127	1044	1772	2057	2184	2184	2089	1804	1139	190	0	0	0	0	0	0	0

5.1.3. Uncertainty in Battery Storage Resources

Table 16 shows the planned battery storage systems in PNM's No New Combustion portfolio. The total energy capacity (MWh) of each system was calculated as the product of the power capacity (MW) and storage duration of each system. The total energy storage capacity was used in the hourly energy balance calculations. Uncertainty in the battery storage capacity and performance was included by sampling the capacity fade and RTE for each annual realization using the uncertainty distributions in Table 11 and applying those to the conditions in Eq. (2).

Table 16. Summary of planned battery storage systems in PNM's No New Combustion, most cost-effective portfolio [1].

Storage System*	Nameplate Capacity (MW)			
	2021	2022	2030	2040
Arroyo Storage ESA (MW)	0	150	150	150
Jicarilla Storage ESA (MW)	0	20	20	20
Rockmont Storage ESA (MW)	0	30	30	30
San Juan Storage ESA (MW)	0	100	100	100
New Lithium Ion Battery (4 hr) (MW)	0	0	508	1025
New Lithium Ion Battery (8 hr) (MW)	0	0	262	391
New Flow Battery (10 hr) (MW)	0	0	0	590
New Pumped Storage (MW)	0	0	0	0
Total storage capacity (MWh)	**0**	**1200**	**5328**	**14328**

*ESA (Energy Storage Agreement) storage systems were assumed to be 4-hour Li-ion batteries for calculating energy capacity

5.1.4. Annual Energy Load

PNM provided the reference forecast for hourly electricity loads to Sandia. For each month, the loads at a particular hour of each day were averaged. Therefore, the hourly load for a particular time each day during a given month were assumed to be the same. For example, the load at 10 AM for each day in March was assumed to be the same. Table 17 shows the average hourly loads (MW) by month for the 2040 reference forecast. The 2040 loads were approximately 6% higher than the 2020 reference loads.

Table 17. Average hourly loads (MW)* by month using reference 2040 forecast (PNM 2020 – 2040 IRP [1]).

	Hourly Load (MW) by Month											
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1014	941	888	853	904	1090	1186	1120	975	874	942	1019
2	963	894	842	808	846	1005	1097	1045	910	829	895	970
3	940	871	820	782	812	950	1042	994	871	805	871	943
4	932	862	814	769	793	916	1007	965	848	794	864	935
5	947	880	826	780	798	908	999	962	850	809	883	951
6	999	933	878	833	843	940	1032	1002	888	859	937	1000
7	1090	1027	966	912	880	956	1053	1061	960	951	1020	1079
8	1126	1037	984	915	885	980	1080	1072	960	982	1023	1103
9	1086	981	932	870	859	988	1093	1070	942	940	959	1061
10	1021	920	868	821	835	1013	1123	1079	927	874	887	988
11	956	855	803	774	817	1044	1167	1107	920	810	826	918
12	906	811	761	750	821	1091	1234	1161	940	775	788	875
13	889	801	749	749	842	1155	1310	1225	978	775	789	861
14	900	813	751	762	884	1235	1389	1307	1036	799	820	879

	Hourly Load (MW) by Month											
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
15	935	846	773	784	940	1323	1481	1405	1125	848	886	934
16	995	898	817	833	1013	1413	1579	1506	1231	927	969	1015
17	1093	987	898	915	1102	1505	1671	1608	1341	1031	1073	1127
18	1234	1105	1005	1008	1201	1589	1742	1684	1436	1142	1204	1279
19	1318	1222	1106	1086	1263	1632	1761	1701	1458	1214	1252	1332
20	1323	1236	1167	1133	1282	1629	1740	1668	1457	1247	1254	1336
21	1311	1226	1183	1181	1303	1606	1715	1650	1428	1224	1247	1331
22	1254	1173	1128	1121	1241	1528	1629	1543	1325	1148	1190	1276
23	1156	1080	1036	1018	1120	1369	1468	1382	1190	1047	1099	1188
24	1070	996	946	922	999	1209	1307	1233	1064	947	1006	1088

*Hourly loads in MW are equivalent to hourly energy requirements in MWh.

5.2. Modeling Results

Results showed that the baseline LOLE (assuming 100% battery performance including 100% RTE and no capacity fade) was 0 days/year with the assumed generation resources, loads, and an assumed initial battery SOC (hour 1 of the year) of 100%.[3] The probabilistic simulations using uncertainty distributions summarized in Table 11 yielded a median LOLE of ~2 days/year and a 95th percentile of LOLE of ~8 days/year. A sensitivity study that reduced the uncertainty distribution for the wind and solar generation from +/- 50% to +/- 25% about the nominal climate-impacted value yielded a similar median LOLE of ~2 days/year and a 95th percentile of LOLE of ~7 days/year. Figure 9 shows the cumulative distribution functions of LOLE for the probabilistic simulations.

Figure 10 shows the results of a rank-regression analysis to determine the impact of uncertainties in the wind and solar resources and battery performance (RTE and capacity fade) on the LOLE using the +/- 50% uniform uncertainty distribution for wind and solar resources. Results show that the battery RTE was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. Figure 11 shows the incremental coefficients of determination for the uncertainty parameters. Uncertainty in the battery RTE yielded the greatest variability in the LOLE, followed by solar resource, wind resource, and battery fade. Similar results were obtained when a +/- 25% uncertainty distribution was assumed.

A sensitivity study was performed to determine how much battery storage capacity was required to reduce the LOLE to 0.2 days/year. In order to reduce the median (50th percentile) LOLE to 0.2 day/year, the battery storage capacity had to be increased from the baseline value of 14,328 MWh to ~25,000 – 30,000 MWh, about a factor of two higher than the baseline value assumed by PNM. In order to reduce the 95th percentile of LOLE to 0.2 day/year, the battery storage capacity had to be increased to ~100,000 MWh (Figure 12), about a factor of seven times higher than the baseline value.

[3] An initial SOC of 0% increased the LOLE to 0.33 days/year for the baseline case. An initial SOC of 10% resulted in an LOLE of 0.2 days/year.

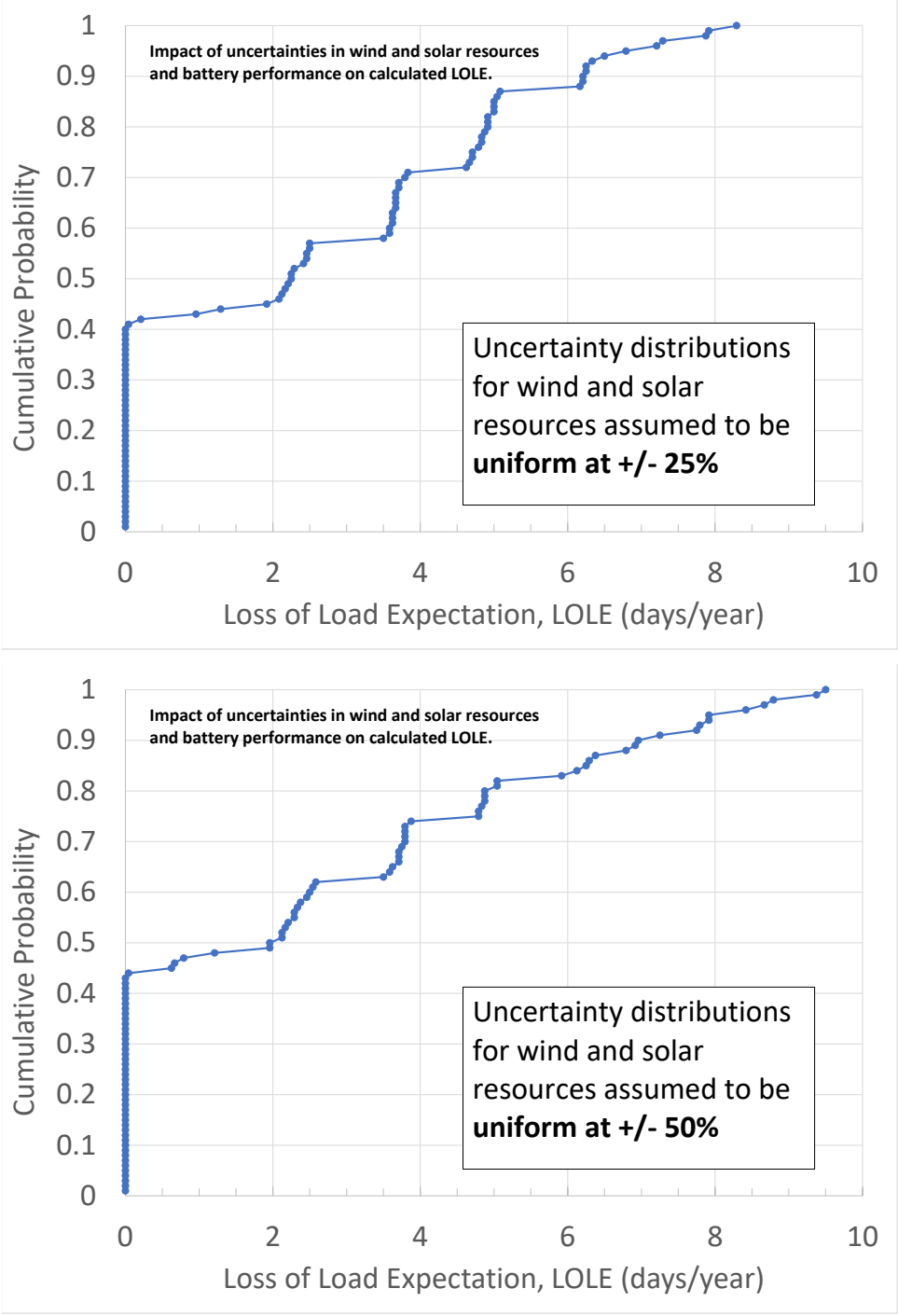


Figure 9. Cumulative probability of loss of load expectation (LOLE) with inclusion of solar and wind resource uncertainty resulting from climate change and uncertainty in battery performance. Uniform distributions of ±25% (top) and ±50% (bottom) were assumed for the solar, wind, and battery performance uncertainty distributions.

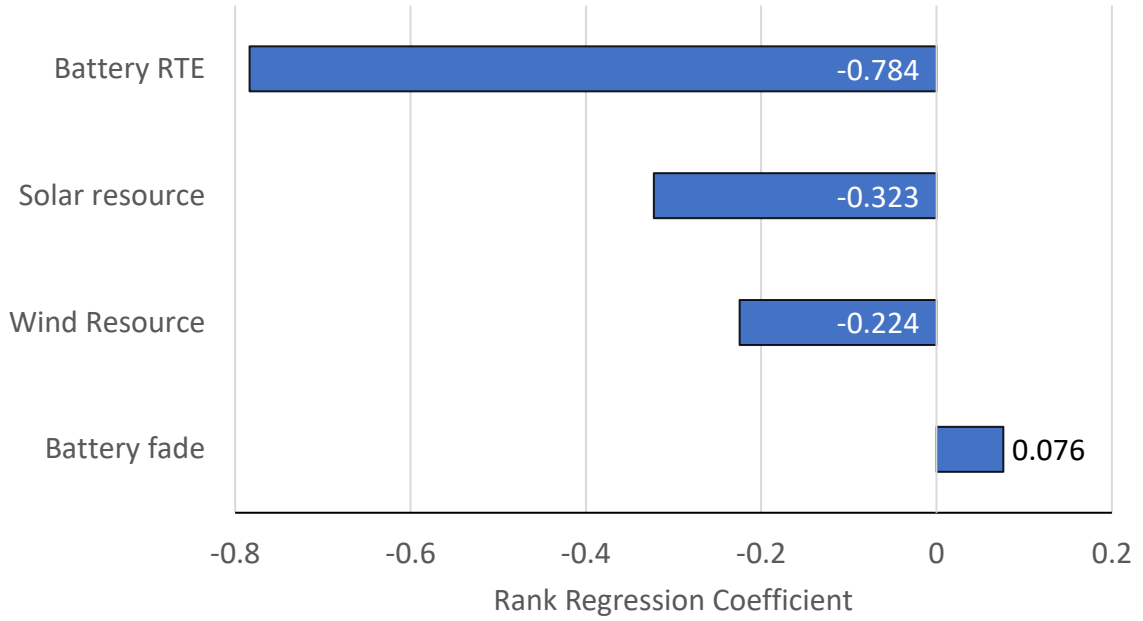


Figure 10. Impact of uncertainties in solar and wind resources and battery performance resulting from climate change on LOLE. Standardized rank regression coefficients are shown. Uniform distributions of ±50% were assumed for the solar, wind, and battery performance uncertainty distributions.

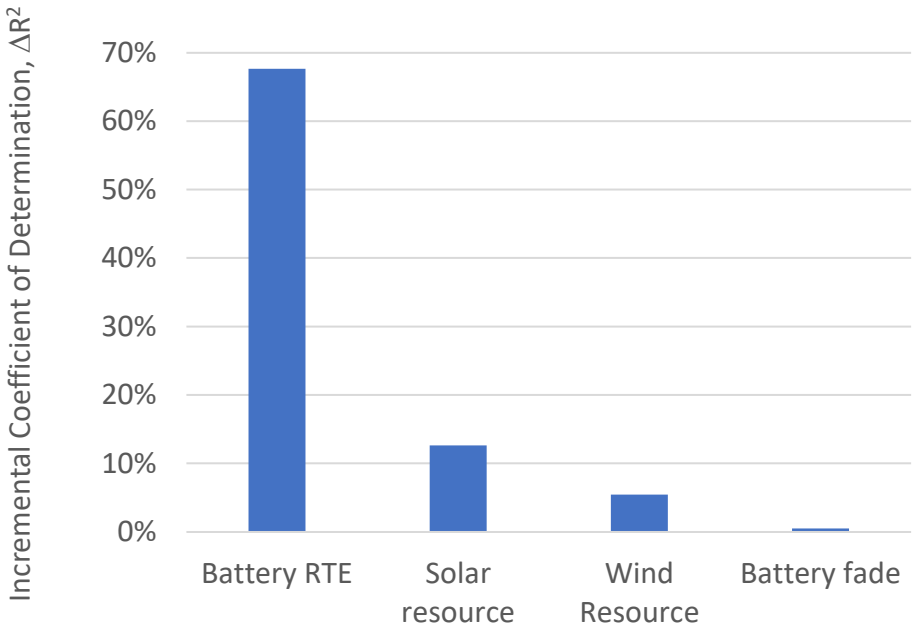


Figure 11. Impact of uncertainties in solar and wind resources and battery performance resulting from climate change on LOLE variability. Incremental coefficients of determination are shown. Uniform distributions of ±50% were assumed for the solar, wind, and battery performance uncertainty distributions.

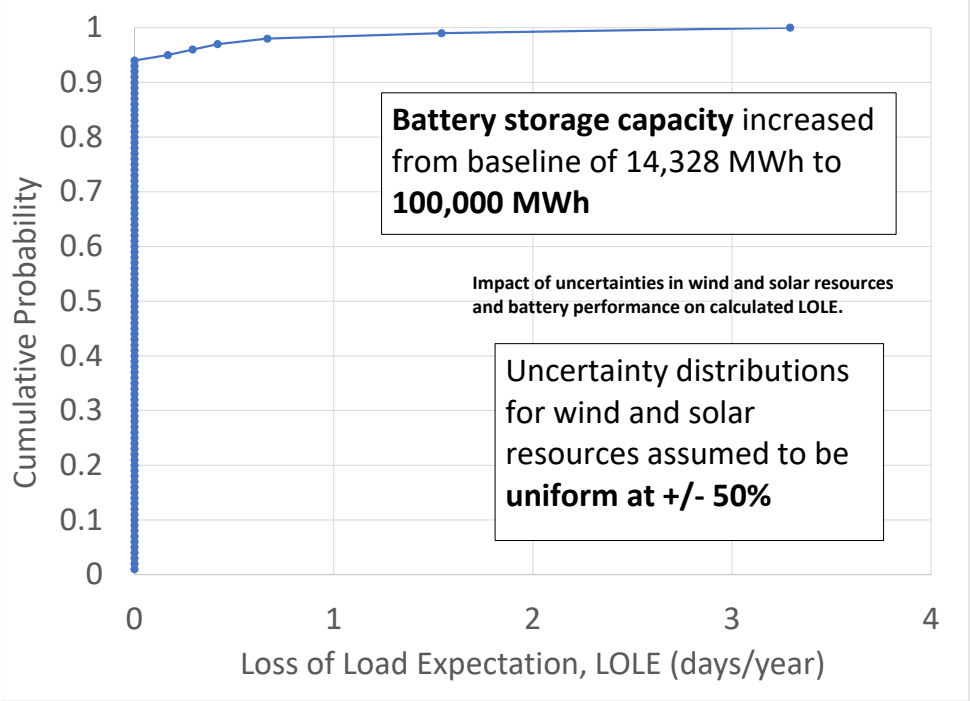


Figure 12. Cumulative probability of LOLE with increased battery storage capacity of 100,000 MWh (from 14,328 MWh) resulting in a 95% confidence that the LOLE would be ≤ 0.2 days/year for assumed uncertainties in solar, wind, and battery performance.

This Page Left Blank

6. CONCLUSION AND RECOMMENDATIONS

New Mexico's Energy Transition Act (ETA) requires power utilities in New Mexico to increase their share of carbon-free electricity generation to 50% by 2030, 80% by 2040, and 100% by 2045. According to its 2020 Integrated Resource Plan, PNM's plan is to rely heavily on utility-scale PV and wind generation with battery energy storage to meet these requirements in the most cost-effective portfolio with no new combustion. The objective of this work was to develop a methodology to evaluate the potential impacts of climate change on wind and solar resources, as well as uncertainties in battery performance, on the annual LOLE.

6.1. Climate Modeling

Three CMPI6 simulations from the E3SM model were chosen for this study to evaluate potential climate-change impacts on wind and solar resources: 'piControl', 'historical', and 'SSP585'. Each of these simulations were chosen to represent a 'no climate change' scenario, a 'low climate change' scenario, and a 'high climate change' scenario, respectively. Surface wind speeds, surface temperatures, and surface downwelling shortwave radiation values were calculated over the state of New Mexico's domain based on temporal and spatial averages from each of the three simulations. Surface temperature over New Mexico was calculated to have a 5.5 °C increase between the 'no climate change' and 'high climate change' scenarios. The solar irradiance was projected to decrease by 2.5% in the worst-cast scenario, and the surface wind speed was calculated to decrease by 8.7%. There was much variability in the averaged variables representing the three climate change scenarios, and it is inconclusive in this study, as well as others, for trends in surface downwelling shortwave radiation and surface wind speeds. The uncertainty and variability within these calculations is transferred to the probabilistic energy storage and production models. Future work could include, but is not limited to, bounding the uncertainty and variability of the climate change scenarios by using higher resolution models, increasing the number of global models used, and assessing trends from other simulation scenarios.

6.2. Climate Impacts on Wind and Solar Energy Resources

A climate-induced 8.7% decrease in average hourly wind speed resulted in a calculated annual decrease in wind energy generation of 13%. Wind generation calculations used a single point for wind speed in order to approximate the impact of a decrease in wind speed on multiple turbines in a wind farm. A 2.5% drop in solar irradiation and a 5.5 °C rise in ambient temperature (in all hours) resulted in roughly a 4% drop in solar PV generation using a large, single-axis PV plant. About half of this drop was due to the decrease in solar irradiation, and about half was due to PV efficiency loss from higher ambient temperatures.

6.3. Climate Impacts on Battery Performance and Storage

Battery performance, life span, and safety are dependent on thermal management. Therefore, battery energy storage systems must be placed inside controlled environments where the temperature is carefully managed. As the ambient temperature rises due to climate change, more energy will be consumed by HVAC systems to maintain the temperature within recommended operating ranges. Modeling results showed that the expected increase in annual energy consumption was less than 2% for climate-induced temperature increases up to 5 °C. Therefore, the potential impact of additional HVAC power consumption was subsumed in the uncertainty of battery round-trip efficiency and capacity fade. Based on reported literature data, the battery RTE was assumed to be uniformly

distributed between 80 – 95%, and the battery capacity fade was assumed to be uniformly distributed between 0 – 20% for any year following installation.

6.4. Energy Balance and Climate Impacts on LOLE

An energy balance was applied to each hour of the year for the most cost-effective portfolio assuming a No New Combustion scenario in 2040 from the PNM 2020 – 2040 IRP, which included nearly 1,000 MW of variable wind energy and ~3,200 MW of variable solar energy capacity. If energy generation exceeded load at any hour, the surplus generation was added to the battery storage system (nameplate capacity ~2,300 MW). Results showed that the baseline LOLE (assuming 100% battery performance including 100% RTE and no capacity fade) was 0 days/year with the assumed generation resources, loads, and an assumed initial battery SOC (hour 1 of the year) of 100%.

In addition to the baseline model, a probabilistic model was developed to evaluate the impacts of climate-induced uncertainties in wind and solar resources, battery RTE, and batter capacity fade on the LOLE. The probabilistic simulations using uncertainty distributions summarized in Table 11 yielded a median LOLE of ~2 days/year and a 95th percentile of LOLE of ~8 days/year. A rank regression analyses revealed that the battery RTE was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. In order to reduce the median (50th percentile) LOLE to 0.2 day/year, the battery storage capacity had to be increased from the baseline value of 14,328 MWh to ~25,000 – 30,000 MWh, about a factor of two higher than the baseline value assumed by PNM. In order to reduce the 95th percentile of LOLE to 0.2 day/year, the battery storage capacity had to be increased to ~100,000 MWh, about a factor of seven times higher than the baseline value assumed by PNM.

Factors such as reliability, maintenance, and uncertainty in load were not included in the models. The primary objective was to develop and demonstrate a method and framework to probabilistically model hourly energy balances that accounted for uncertainties in variable resource generation, battery performance, and climate impacts. These methods can be utilized in future IRPs and models to gain confidence in future resource portfolios that can achieve 100% carbon-free electricity production by 2045 as prescribed in NM's Energy Transition Act.

REFERENCES

[1] Phillips, N., M. Reiman, D. Brunton, S. Gutierrez, and J. Heslop, 2021, PNM 2020 - 2040 Integrated Resource Plan, Public Service Company of New Mexico, Albuquerque, NM. January 29, 2021 https://www.pnmforwardtogether.com/irp.

[2] Burrows, S.M., M. Maltrud, X. Yang, Q. Zhu, N. Jeffery, X. Shi, D. Ricciuto, S. Wang, G. Bisht, J. Tang, J. Wolfe, B.E. Harrop, B. Singh, L. Brent, S. Baldwin, T. Zhou, P. Cameron-Smith, N. Keen, N. Collier, M. Xu, E.C. Hunke, S.M. Elliott, A.K. Turner, H. Li, H. Wang, J.-C. Golaz, B. Bond-Lamberty, F.M. Hoffman, W.J. Riley, P.E. Thornton, K. Calvin, and L.R. Leung, 2020, The DOE E3SM v1.1 Biogeochemistry Configuration: Description and Simulated Ecosystem-Climate Responses to Historical Changes in Forcing, *Journal of Advances in Modeling Earth Systems*, **12**(9), p. e2019MS001766.

[3] Eyring, V., S. Bony, G.A. Meehl, C.A. Senior, B. Stevens, R.J. Stouffer, and K.E. Taylor, 2016, Overview of the Coupled Model Intercomparison Project Phase 6 (CMIP6) experimental design and organization, *Geosci. Model Dev.*, **9**(5), p. 1937-1958.

[4] Golaz, J.-C., P.M. Caldwell, L.P.V. Roekel, M.R. Petersen, Q. Tang, J.D. Wolfe, G. Abeshu, V. Anantharaj, X.S. Asay-Davis, D.C. Bader, S.A. Baldwin, G. Bisht, P.A. Bogenschutz, M. Branstetter, M.A. Brunke, S.R. Brus, S.M. Burrows, P.J. Cameron-Smith, A.S. Donahue, M. Deakin, R.C. Easter, K.J. Evans, Y. Feng, M. Flanner, J.G. Foucar, J.G. Fyke, B.M. Griffin, C. Hannay, B.E. Harrop, M.J. Hoffman, E.C. Hunke, R.L. Jacob, D.W. Jacobsen, N. Jeffery, P.W. Jones, N.D. Keen, S.A. Klein, V.E. Larson, L.R. Leung, H.-Y. Li, W. Lin, W.H. Lipscomb, P.-L. Ma, S. Mahajan, M.E. Maltrud, A. Mametjanov, J.L. McClean, R.B. McCoy, R.B. Neale, S.F. Price, Y. Qian, P.J. Rasch, J.E.J.R. Eyre, W.J. Riley, T.D. Ringler, A.F. Roberts, E.L. Roesler, A.G. Salinger, Z. Shaheen, X. Shi, B. Singh, J. Tang, M.A. Taylor, P.E. Thornton, A.K. Turner, M. Veneziani, H. Wan, H. Wang, S. Wang, D.N. Williams, P.J. Wolfram, P.H. Worley, S. Xie, Y. Yang, J.-H. Yoon, M.D. Zelinka, C.S. Zender, X. Zeng, C. Zhang, K. Zhang, Y. Zhang, X. Zheng, T. Zhou, and Q. Zhu, 2019, The DOE E3SM Coupled Model Version 1: Overview and Evaluation at Standard Resolution, *Journal of Advances in Modeling Earth Systems*, **11**(7), p. 2089-2129.

[5] Tebaldi, C., K. Debeire, V. Eyring, E. Fischer, J. Fyfe, P. Friedlingstein, R. Knutti, J. Lowe, B. O'Neill, B. Sanderson, D. van Vuuren, K. Riahi, M. Meinshausen, Z. Nicholls, K.B. Tokarska, G. Hurtt, E. Kriegler, J.-F. Lamarque, G. Meehl, R. Moss, S.E. Bauer, O. Boucher, V. Brovkin, Y.-H. Byun, M. Dix, S. Gualdi, H. Guo, J.G. John, S. Kharin, Y. Kim, T. Koshiro, L. Ma, D. Olivié, S. Panickal, F. Qiao, X. Rong, N. Rosenbloom, M. Schupfner, R. Séférian, A. Sellar, T. Semmler, X. Shi, Z. Song, C. Steger, R. Stouffer, N. Swart, K. Tachiiri, Q. Tang, H. Tatebe, A. Voldoire, E. Volodin, K. Wyser, X. Xin, S. Yang, Y. Yu, and T. Ziehn, 2021, Climate model projections from the Scenario Model Intercomparison Project (ScenarioMIP) of CMIP6, *Earth System Dynamics*, **12**(1), p. 253-293.

[6] Solaun, K. and E. Cerdá, 2019, Climate change impacts on renewable energy generation. A review of quantitative projections, *Renewable and Sustainable Energy Reviews*, **116**, p. 109415.

[7] Craig, M.T., S. Cohen, J. Macknick, C. Draxl, O.J. Guerra, M. Sengupta, S.E. Haupt, B.-M. Hodge, and C. Brancucci, 2018, A review of the potential impacts of climate change on bulk power system planning and operations in the United States, *Renewable and Sustainable Energy Reviews*, **98**, p. 255-267.

[8] Craig, M.T., I.L. Carreño, M. Rossol, B.-M. Hodge, and C. Brancucci, 2019, Effects on power system operations of potential changes in wind and solar generation potential under climate change, *Environmental Research Letters*, **14**(3), p. 034014.

[9] Losada Carreño, I., M.T. Craig, M. Rossol, M. Ashfaq, F. Batibeniz, S.E. Haupt, C. Draxl, B.-M. Hodge, and C. Brancucci, 2020, Potential impacts of climate change on wind and solar electricity generation in Texas, *Climatic Change*, **163**(2), p. 745-766.

[10] Haupt, S.E., J. Copeland, W.Y.Y. Cheng, Y. Zhang, C. Ammann, and P. Sullivan, 2016, A Method to Assess the Wind and Solar Resource and to Quantify Interannual Variability over the United States under Current and Projected Future Climate, *Journal of Applied Meteorology and Climatology*, **55**(2), p. 345-363.

[11] Mearns, L., S. McGinnis, D. Korytina, R. Arritt, S. Biner, M. Bukovsky, H.-I. Chang, O. Christensen, D. Herzmann, Y. Jiao, S. Kharin, M. Lazare, G. Nikulin, M. Qian, J. Scinocca, K. Winger, C. Castro, A. Frigon, and W. Gutowski, *The NA-CORDEX dataset*, 2017, UCAR/NCAR.

[12] Skamarock, W., J. Klemp, J. Dudhia, D. Gill, D. Barker, W. Wang, X.-Y. Huang, and M. Duda, 2008, A Description of the Advanced Research WRF Version 3, UCAR/NCAR, 1002 KB 2008-06

[13] Chen, L., 2020, Impacts of climate change on wind resources over North America based on NA-CORDEX, *Renewable Energy*, **153**, p. 1428-1438.

[14] Pryor, S.C., R.J. Barthelmie, M.S. Bukovsky, L.R. Leung, and K. Sakaguchi, 2020, Climate change impacts on wind power generation, *Nature Reviews Earth & Environment*, **1**(12), p. 627-643.

[15] Crook, J.A., L.A. Jones, P.M. Forster, and R. Crook, 2011, Climate change impacts on future photovoltaic and concentrated solar power energy output, *Energy & Environmental Science*, **4**(9), p. 3101-3109.

[16] Folini, D., T.N. Dallafior, M.Z. Hakuba, and M. Wild, 2017, Trends of surface solar radiation in unforced CMIP5 simulations, *Journal of Geophysical Research: Atmospheres*, **122**(1), p. 469-484.

[17] Haupt, S.E., B. Kosović, T. Jensen, J.K. Lazo, J.A. Lee, P.A. Jiménez, J. Cowie, G. Wiener, T.C. McCandless, M. Rogers, S. Miller, M. Sengupta, Y. Xie, L. Hinkelman, P. Kalb, and J. Heiser, 2018, Building the Sun4Cast System: Improvements in Solar Power Forecasting, *Bulletin of the American Meteorological Society*, **99**(1), p. 121-136.

[18] Huber, I., L. Bugliaro, M. Ponater, H. Garny, C. Emde, and B. Mayer, 2016, Do climate models project changes in solar resources?, *Solar Energy*, **129**, p. 65-84.

[19] Chen, L., 2021, Uncertainties in solar radiation assessment in the United States using climate models, *Climate Dynamics*, **56**(1), p. 665-678.

[20] Jackson, N.D. and T. Gunda, 2021, Evaluation of extreme weather impacts on utility-scale photovoltaic plant performance in the United States, *Applied Energy*, **302**, p. 117508.

[21] Jiménez, P.A., S. Alessandrini, S.E. Haupt, A. Deng, B. Kosovic, J.A. Lee, and L.D. Monache, 2016, The Role of Unresolved Clouds on Short-Range Global Horizontal Irradiance Predictability, *Monthly Weather Review*, **144**(9), p. 3099-3107.

[22] Wang, M., P. Ullrich, and D. Millstein, 2020, Future projections of wind patterns in California with the variable-resolution CESM: a clustering analysis approach, *Climate Dynamics*, **54**(3), p. 2511-2531.

[23] Millstein, D., J. Solomon-Culp, M. Wang, P. Ullrich, and C. Collier, 2019, Wind energy variability and links to regional and synoptic scale weather, *Climate Dynamics*, **52**(7), p. 4891-4906.

[24] National Renewable Energy Laboratory. *Wind Prospector*. [Accessed 2021]; Available from: https://maps.nrel.gov/wind-prospector.

[25] International Electrotechnical Commission, 2005, Wind turbines - Part 1: Design requirements, IEC 61400-1:2005, https://webstore.iec.ch/publication/5426.

[26] Kalmikov, A., K. Dykes, and K. Araujo, Wind Power Fundamentals, MIT, https://web.mit.edu/windenergy/windweek/Presentations/Wind%20Energy%20101.pdf.

[27] King, J., A. Clifton, and B.M. Hodge, 2014, Validation of Power Output for the WIND Toolkit, National Renewable Energy Laboratory, NREL/TP-5D00-61714, Golden, CO. https://www.nrel.gov/docs/fy14osti/61714.pdf.

[28] Newman, J.F. and P.M. Klein, 2014, The Impacts of Atmospheric Stability on the Accuracy of Wind Speed Extrapolation Methods, *Resources*, **3**(1), p. 81-105.

[29] Holmgren, W.F., C.W. Hansen, and M.A. Mikofski, 2018, pvlib python: a python package for modeling solar energy systems, *The Journal of Open Source Software*, **3**(29).

[30] Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby, 2018, The National Solar Radiation Data Base (NSRDB), *Renewable and Sustainable Energy Reviews*, **89**, p. 51-60.

[31] Preger, Y., H.M. Barkholtz, A. Fresquez, D.L. Campbell, B.W. Juba, J. Romàn-Kustas, S.R. Ferreira, and B. Chalamala, 2020, Degradation of Commercial Lithium-Ion Cells as a Function of Chemistry and Cycling Conditions, *Journal of The Electrochemical Society*, **167**(12), p. 120532.

[32] Spotnitz, R., 2003, Simulation of capacity fade in lithium-ion batteries, *Journal of Power Sources*, **113**(1), p. 72-80.

This Page Left Blank

DISTRIBUTION

Email—Internal

Name	Org.	Sandia Email Address
Technical Library	01911	sanddocs@sandia.gov



Sandia National Laboratories is a multimission laboratory managed and operated by National Technology & Engineering Solutions of Sandia LLC, a wholly owned subsidiary of Honeywell International Inc. for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA0003525.

Foundational Issues PNM 2023 IRP

Cynthia Mitchell, Energy Economist[i]

May 4, 2023

PNM's 2023 IRP must consider solar, wind, energy storage, and demand response + energy efficiency in a distinctly different manner than their 2020 IRP.

- PNM's assumption regarding the effective capacity[ii] of solar, wind, storage resulted in a 100 – 133% increase in capacity requirements over the twenty-year period (2021 3,000 MW to 2040 6,000 – 7,000 MW),[iii] when the 20-year forecast of demand increases only 20%.[iv]
  - PNM does not pair storage with solar as a firming resource to improve the effective capacity of solar.[v]
  - Wind, solar, and storage were otherwise conceptually siloed or isolated from one another, giving the impression that there are negative effects from solar.[vi]
  - PNM assumed that under its 20-year "Current Trends & Policy Future" wind, solar, and storage decrease over time.[vii]

- PNM considered negligible demand response and energy efficiency (DR + EE) and assumed that DR + EE decrease to zero by 2031 for DR, and 2038 for EE.[viii]

- PNM assumed that 606 MW of "hydrogen-ready" new-build gas combustion turbines were for reliability purposes and would rarely run. This equates to essentially a 30% planning reserve margin (PRM), (606 MW CTs / 2,363 MW peak load 2040).[ix]

- It is not possible to compare the costs of new gas generation to wind, solar, and energy storage because PNM does not present resource costs by levelized cost of energy (LCOE).[x]

- Even with these foundational issues that bias the analysis to favor gas CTs, the no-CT portfolio costs only $188M or 2.8% more, over 20-year period, net present value basis (NPV). Hydrogen-ready CTs: $6,841M NPV to No CTs: $7,029M NPV.
  - In modeling terms, this difference is di minimis.
  - Because the CT and no-CT portfolios likely over forecasted the amounts of new wind, solar and storage needed to replace coal and gas, and because neither portfolio utilizes DR+EE as a utility resource, a more integrated analysis should result in a much lower forecast of future revenue requirements in a no gas portfolio.

For PNM's 2023 IRP, these are the foundational issues across all scenarios, futures, and sensitivities that should be vetted prior to modeling.

The end game of the stakeholder process should be real options to pursue in the action plan period, particularly as it relates to storage and DR + EE.

[i] I am a near 50-year veteran in energy policy and utility regulation, an expert on utility integrated resource planning, focused on sustainability through distributed energy resources (energy efficiency, demand response, energy storage), and renewable energy. As an economist, I have worked for Attorney General Consumer Advocates around the country, including about 20 years in California for TURN, The Utility Reform Network. I moved to Santa Fe, New Mexico October 2020. Please contact me for a copy of my CV-resume. cynthiakmitchell@gmail.com.

ii ELCC Effective Load Carrying Capacity is the preferred method of measuring the capacity contribution of non-firm resources. **Note:** The derivation of ELCCs is complex via generally opaque modeling. Understanding the logic and key assumptions and algorithms used to calculate ELCCs, whether PNM's 2020 ELCCs for standalone solar and wind are reasonable, and how higher diversity benefit values from say using storage to firm solar, can be achieved, is critical going forward.

iii PNM 2020 IRP, Figure 4.

iv PNM 2020 IRP, Table 22.

v While solar effective capacity does decline as penetration increases, storage can be paired with solar to "firm" its intermediacy and improve its effective capacity. In fact, PNM's filing for the replacement of San Juan resources includes four solar + storage projects totaling 650 MW of solar and 300 MW of storage. (See Table 2). However, the modeling of the solar + storage does not appear to pair storage as a firming resource. For instance, in 2022, solar nameplate to effective capacity is cut by 83%, and in 2040 cut for a total of 94%. C Mitchell, PNM Table 2 and Appendix K.

- Storage otherwise is not paired with solar in PNM's 2020 IRP, with solar ELCCs between 8-10%, and wind 22%, 2040. (See Table 3).
- PNM's EnCompass model apparently did not include the logic to capture the synergistic effects between resources explicitly. PNM 2020 IRP 5.4.1.
- In sum, PNM needs a new worldview of storage in PNM's 2023 IRP, one that considers how "energy storage is like a Swiss army knife, and it has many uses and applications." E3 Consulting ppt Overview of E3 Storage Capabilities", 2/26/2019 (Resolve et al model)

vi PNM 2020 IRP Figure 23.

vii PNM 2020 IRP Table 22.

viii PNM 2020 IRP Table 22.

DR is listed as the last resource and included in the sum of "total generation". DR should be first resource and netted out of gross peak in the net peak calculation. This would reduce the MWs for the planning reserve margin (PRM).

Per PNM's 2020 IRP, Appendix L-3, there are two DR programs, Power Saver and Peaker Saver. Per a newspaper ad last Summer 2022, PNM also ran a PNM "Flex Your Power" program - customer initiated to join, where PNM communicated when curtailments would be helpful.

An update on these and any additional DR activities and programs (existing and planned), should be provided, including: Dispatch history, days and time, duration correlated to peaks (how measured, derived); Location on distribution system; Number of participants and incentives paid.

Note: DR + EE are multi-attribute resources that can no longer be essentially ignored by PNM. A key focus of the stakeholder process should be on developing a much more robust approach to DR + EE that is implemented asap.

ix There are several other concerns regarding key assumptions re HRCTs that should be resolved, including: PNM maintains a large fleet of gas gen up to 2040 when "poof", it becomes hydrogen! (987 MW gas 2021 - 2027; 2031 - 2039 692 MW; then 2040 0 MW).

The use of CTs for supposedly planning reliability only also raises the questions regarding PNM's 18% PRM applied to peak demand. The 2017 IRP dropped RM to 13%; was 15%. PNM has increased to 18% given increasing solar and storage penetration. Questions: Where on the system does the peak occur and how determined, measured? Cause(s) of the peak identified by distribution station, circuit, line, feeder. How does an additional 350+MW added to total resources (assume 2000 MW peak * 18%) provide reliability to the most common service disruption: Distribution.

x See Lazard's Comparative LCOE data Comparison – Unsubsidized Analysis, p.2 shows that: Solar PV+Storage-Utility Scale: $46 – 102 LCOE. Gas Peaking $115 -221 LCOE.
https://www.lazard.com/research-insights/2023

x

TITLE 17 PUBLIC UTILITIES AND UTILITY SERVICES
CHAPTER 7 ENERGY CONSERVATION
PART 3 INTEGRATED RESOURCE PLANS FOR ELECTRIC UTILITIES

17.7.3.1 ISSUING AGENCY: New Mexico Public Regulation Commission.
[17.7.3.1 NMAC - N, 4/16/2007]

17.7.3.2 SCOPE:

A. This rule applies to all electric utilities subject to the commission's jurisdiction over integrated resource planning.

B~~A~~. Impact on Other Rules: ~~-~~Except as specifically provided herein, this rule does not supersede any other rule of the commission but is to be construed as a supplement to such rules.

C~~B~~. Severability: ~~-~~If any part or application of this rule is held invalid, the remainder of its application shall not be affected.

[17.7.3.2 NMAC - N, 4/16/2007; A, 9/14/2022]

17.7.3.3 STATUTORY AUTHORITY: ~~This rule is adopted under the authority vested in this commission by the New Mexico Public Regulation Commission Act, Section 8-8-15 NMSA 1978; the Public Utility Act, Section 62-3-1 NMSA 1978, et seq.; and the Efficient Use of Energy Act, Section 62-17-1 NMSA 1978, et seq.~~ ~~[17.7.3.3 NMAC - N, 4/16/2007; A, 8/29/2017]~~ This rule is adopted under the authority vested in this commission by the New Mexico Constitution, Article XI, Section 2; the Public Regulation Commission Act, Sections 8-8-4(B)(10) and 8-8-15 NMSA 1978; the Public Utility Act, Section 62-3-1 NMSA 1978, *et seq.*, Section 62-3-2, Section 62-3-3(H), Section 62-6-4, Section 62-8-1, and Section 62-8-13; the Efficient Use of Energy Act, Section 62-17-1 NMSA 1978, *et seq.*, and Section 62-17-10; the Renewable Energy Act, Section 62-16-1 NMSA 2004, as amended 2021, *et seq.*; the Energy Transition Act, 62-18-1 NMSA 2019 *et seq.*; the grid modernization statute, Section 62-8-13 NMSA 1978; and the Community Solar Act, Section 62-16B-1 NMSA 1978, *et seq.*
[17.7.3.3 NMAC - N, 4/16/2007; A, 8/29/2017; A, 9/14/2022]

17.7.3.4 DURATION: Permanent.
[17.7.3.4 NMAC - N, 4/16/2007]

17.7.3.5 EFFECTIVE DATE: April 16, 2007, unless a later date is cited at the end of a section.
[17.7.3.5 NMAC - N, 4/16/2007]

17.7.3.6 OBJECTIVE: ~~The purpose 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. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts.~~
~~[17.7.3.6 NMAC - N, 4/16/2007]~~

A. 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. This rule regulates utility integrated resource planning and procurement consistent with the Commission's statutory obligations to ensure fair, just, and reasonable rates.

B. This rule serves the Commission's objectives of increasing transparency, involving stakeholder participation early in the process, and tying the IRP outcome directly to the procurement process.

C. To assist utilities in identifying the most cost-effective portfolio, this rule establishes a transparent, competitive format for analyzing alternative resource portfolio plans.

D. This format promotes fair and robust competition in selection of resources to ensure consistency, efficiency, and harmony with the integrated resource planning and procurement process.

(1) In proposing cost-effective resources, utilities shall prioritize those that best comply with the state's requirements for reducing greenhouse gas emissions, fostering equitable clean energy development, and grid modernization.

(2) Utilities shall consider the following resources, including but not limited to: distributed energy resources, demand response, energy efficiency, renewable energy, flexible generation, , low-emission or zero carbon resources, energy storage systems, and transmission and distribution grid improvements.

[17.7.3.6 NMAC – N, 4/16/2007; A, 9/14/2022]

17.7.3.7 DEFINITIONS: When used in this rule, unless otherwise specified the following definitions will apply:

~~**A. availability factor** means the ratio of the time a generating facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured;~~

~~**B. capacity factor** means the ratio of the net energy produced by a generating facility during a given time period, to the amount of net energy that could have been produced if the facility operated continuously at full capacity during that same time period;~~

~~**C. demand-side resources** means energy efficiency and load management, as those terms are defined in the Efficient Use of Energy Act;~~

~~**D. energy efficiency** means measures, including energy conservation measures, or programs that target consumer behavior, equipment or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services;~~

~~**E. energy storage resource** means a commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter delivering the energy;~~

~~**F. heat rate** means the ratio of energy inputs used by a generating facility expressed in BTUs (British thermal units), to the energy output of that facility expressed in kilowatt hours;~~

~~**G. integrated resource plan** (IRP) means a public utility's plan to meet New Mexico jurisdictional retail customers' existing and future demand in accordance with this rule;~~

~~**H. load forecasting** means the prediction of the demand for electricity over the planning period for the utility;~~

~~**I. load management** means measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off peak periods;~~

~~**J. most cost effective resource portfolio** means those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations;~~

~~**K. planning period** means the future period for which a utility develops its IRP; for purposes of this rule, the planning period is 20 years;~~

~~**L. public utility or utility has the same** meaning as in the Public Utility Act, except that it does not include a distribution cooperative utility, as defined in the Efficient Use of Energy Act;~~

~~**M. renewable energy** means electrical energy generated by means of a low or zero emissions generation technology with substantial long-term production potential and generated by use of renewable energy resources that may include solar, wind, hydropower, geothermal, fuel cells that are not fossil fueled and biomass resources; biomass resources are fuels, such as agriculture or animal waste, small diameter timber, salt cedar and other phreatophyte or woody vegetation removed from river basins or watersheds in New Mexico, landfill gas and anaerobically digested waste biomass; renewable energy does not include fossil fuel or nuclear energy.~~

~~[17.7.3.7 NMAC – N, 4/16/2007; A, 8/29/2017]~~

~~**17.7.3.8 GENERAL PROVISIONS:** The commission adopts this rule in order to fulfill the requirements of Section 62-17-10 NMSA 1978.~~

~~[17.7.3.8 NMAC – N, 4/16/2007; A, 8/29/2017]~~

A. action plan means the proposed process and specific actions the utility shall carry out to implement the integrated resource plan spanning a three (3) year period following the filing of the utility's integrated resource plan;

B. availability factor means the ratio of the time a generating facility is available to produce energy at its rated capacity to the total amount of time in the period being measured;

C. capacity factor means the ratio of the net energy produced by a generating facility during a given time period to the amount of net energy that could have been produced if the facility operated continuously at full capacity during that same time period;

D. demand response means a form of load management that involves changes in electric usage by end-use customers from their normal consumption patterns, either in response to changes in the price of electricity

over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized;

E. demand-side resource means storage, responsive distributed generation, and loads engaged in demand response programs that can support the grid by responding to market signals or direct load control;

F. derating means a temporary or permanent reduction in the expected power output of a generating facility;

G. distributed energy resource (DER) means the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. DER may include, but is not limited to: an electric generator and/or energy storage system, a prime mover, or combination of technologies capable of injecting power and energy into the electric distribution system, which also includes the interconnection equipment necessary to safely interconnect with the distribution system. DER may not always be interconnected with the bulk power system. DER may include distributed generation resources, distributed energy storage, demand response energy efficiency, and electric vehicles and chargers that are connected to the electric distribution power grid. DER may be capable of exporting active power to an electric power system. DER includes the customer's interconnection facilities but shall not include the area electric power system operator's interconnection facilities;

H. emergency procurement means a utility's procurement to address a system-based emergency condition including a serious threat to public health, welfare, safety, or property caused by a flood, fire, epidemic, riot, act of terrorism, equipment failure, or similar event.

I. energy efficiency means measures, including energy conservation measures, or programs that target consumer behavior, equipment, or devices, to result in a decrease in consumption of electricity without reducing the quantity or quality of energy services;

J. energy storage resource means a commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter delivering the energy. Specifically, it means a commercially available technology that:

(1) uses mechanical, chemical, or thermal processes to:

(a) store energy, including energy generated from renewable energy resources and energy that would otherwise be wasted, and deliver the stored energy for use at a later time; or

(b) store thermal energy for direct use for heating or cooling at a later time in a manner that reduces the demand for electricity at the later time;

(2) is composed of stationary equipment;

(3) if being used for electric grid benefits, is operationally visible and capable of being controlled by the distribution or transmission entity managing it, to enable and optimize the safe and reliable operation of the electric system; and

(4) achieves any of the following:

(a) reduces peak electrical demand;

(b) defers the need, or substitutes for, an investment in electric generation, transmission, or distribution assets;

(c) improves the reliable operation of the electrical transmission or distribution systems; or

(d) lowers customer costs by storing energy when the cost of generating or purchasing it is low and delivering it to customers when the costs are high;

K. facilitated stakeholder process means the statutory public advisory process pursuant to NMSA 1978, Section 62-17-10 (2005), conducted by a Commission appointee to facilitate advisory discussions among stakeholders, including members of the public, to advise the public utility and reach potential agreement in the utility's development of its statement of need and action plan;

L. flexibility means the ability of a power system or resource to timely respond as needed to changes in supply and demand through deployment or curtailment of resources by system managers or other control methods, to maintain a balanced load, and to compensate for the variability of renewable energy resources;

M. flexible generation means generation resources that can start, ramp up, and ramp down quickly and efficiently, can be dispatched, and run at low output levels, and can serve frequency response and ancillary service needs, as needed;

N. heat rate means the ratio of energy inputs used by a generating facility expressed in British thermal units, to the energy output of that facility expressed in kilowatt-hours;

O. integrated resource plan (IRP) means a public utility's plan to meet New Mexico jurisdictional retail customers' existing and future demand in accordance with this rule and applicable state policies. Specifically, it means a set of resource options that a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the supply and demand circumstances under which, and the

extent to which, each resource option would be used to meet those service needs. These resource options include, but are not limited to, using, refurbishing, and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation;

P. independent monitor (IM) means a person or entity appointed by the commission to oversee the conduct of a utility's competitive procurement process as addressed in this rule. The IM shall report to the commission regarding the utility's conformance with the most recently accepted statement of need and action plan and the sufficiency, reasonableness, competitive fairness, and completeness of that process;

Q. load forecasting means the prediction of the demand for electricity and energy over the planning period for the utility;

R. load management means measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off-peak periods;

S. most cost-effective resource portfolio means those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations;

T. net capacity means the amount of flexible capacity necessary to supply instantaneous demand over and above the available capacity from variable energy resources, including wind and solar generation;

U. net load means the difference between forecasted load and expected electricity production from variable generation resources;

V. planning period means the future period for which a utility develops its IRP, which, for purposes of this rule, is 20 years;

W. public utility or **utility** has the same meaning as in the Public Utility Act, except that it does not include a distribution cooperative utility as defined in the Efficient Use of Energy Act;

X. regional energy market means an organized interstate market for energy, ancillary services, or capacity, operated by an independent entity (Independent System Operator or Regional Transmission Operator) subject to regulatory authority of the Federal Energy Regulatory Commission;

Y. renewable energy means electrical energy generated by use of renewable energy resources and delivered to a public utility;

Z. renewable energy resource means the following energy resources, with or without energy storage:

(1) solar, wind and geothermal;

(2) hydropower facilities brought in service on or after July 1, 2007;

(3) biomass resources, limited to agriculture or animal waste, small diameter timber, not to exceed eight inches, salt cedar and other phreatophyte or woody vegetation removed from river basins or watersheds in New Mexico; provided that these resources are from facilities certified by the energy, minerals and natural resources department to:

(a) be of appropriate scale to have sustainable feedstock in the near vicinity;

(b) have zero life cycle carbon emissions; and

(c) meet scientifically determined restoration, sustainability and soil nutrient principles;

(4) fuel cells that do not use fossil fuels to create electricity; and

(5) landfill gas and anaerobically digested waste biogas; and

AA. statement of need means a description and explanation of the amount and type of new resources, expressed in terms of energy and/or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies

[17.7.3.7 NMAC - N, 4/16/2007; A, 8/29/2017; A, 9/14/2022]

17.7.3.~~8~~9 INTEGRATED RESOURCE PLANS FOR ELECTRIC UTILITIES: ~~Public utilities supplying electric service to customers shall file an IRP, along with an action plan, with the commission every three years.~~

~~**A.** Initial filings. Utilities with greater than 200,000 New Mexico retail customers shall file 15 months after the effective date of this rule. Utilities with less than 200,000 New Mexico retail customers shall file 27 months after the effective date of this rule. An original and fourteen copies of the IRP shall be filed with the commission.~~

~~**B.** Contents of IRP for electric utilities. The IRP submitted by an electric utility shall contain the utility's New Mexico jurisdictional:~~

~~**(1)** description of existing electric supply-side and demand-side resources;~~

~~**(2)** current load forecast as described in this rule;~~

(3) load and resources table;
(4) identification of resource options;
(5) description of the resource and fuel diversity;
(6) identification of critical facilities susceptible to supply source or other failures;
(7) determination of the most cost effective resource portfolio and alternative portfolios;
(8) description of public advisory process;
(9) action plan; and
(10) other information that the utility finds may aid the commission in reviewing the utility's planning processes.

C. Description of existing resources. The utility's description of its existing resources used to serve its jurisdictional retail load at the time the IRP is filed shall include:
(1) name(s) and location(s) of utility-owned generation facilities;
(2) rated capacity of utility-owned generation facilities;
(3) fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities over the planning period;
(4) cost information, including capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs;
(5) existing generation facilities' expected retirement dates;
(6) amount of capacity obtained or to be obtained through existing purchased power contracts or agreements relied upon by the utility, including the fuel type, if known, and contract duration;
(7) estimated in-service dates for utility-owned generation facilities for which a certificate of public convenience and necessity (CCN) has been granted but which are not in service;
(8) amount of capacity and, if applicable, energy, provided annually to the utility pursuant to wheeling agreements and the duration of such wheeling agreements;
(9) description of existing demand-side resources, including
(a) demand-side resources deployed at the time the IRP is filed; and
(b) demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed; information provided concerning existing demand-side resources shall include, at a minimum, the expected remaining useful life of each demand-side resource and the energy savings and reductions in peak demand, as appropriate, made by the demand-side resource.
(10) description of each existing and approved energy storage resources, to include, at a minimum, the expected remaining useful life of the resource, its maximum capacity and dispatch characteristics, and operating costs;
(11) reserve margin and reserve reliability requirements (e.g. FERC, power pool, etc.) with which the utility must comply and the methodology used to calculate its reserve margin;
(12) existing transmission capabilities:
(a) the utility shall report its existing, and under-construction, transmission facilities of 115 kV and above, including associated switching stations and terminal facilities; the utility shall specifically identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of supply-side resources;
(b) the utility shall describe all transmission planning or coordination groups to which it is a party, including state and regional transmission groups, transmission companies, and coordinating councils with which the utility may be associated.
(13) environmental impacts of existing supply-side resources:
(a) the utility shall provide the percentage of kilowatt-hours generated by each fuel used by the utility on its existing system, for the latest year for which such information is available;
(b) to the extent feasible, for each existing supply-side resource on its system, the utility shall present emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury;
(c) to the extent feasible, for each existing supply-side resource on its system, the utility shall present the water consumption rate.
(14) a summary of back-up fuel capabilities and options.

D. Current load forecast.
(1) The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections:

(a) annual sales of energy and coincident peak demand on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;

(b) annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system;

(c) weather normalization adjustments;

(d) assumptions for economic and demographic factors relied on in load forecasting;

(e) expected capacity and energy impacts of existing and proposed demand-side resources; and

(f) typical historic day or week load patterns on a system-wide basis for each major customer class.

(2) The utility shall develop base-case, high-growth and low-growth forecasts, or an alternative forecast that provides an assessment of uncertainty (e.g., probabilistic techniques).

(3) Required detail.

(a) The utility shall explain how the demand-side savings attributable to actions other than the utility-sponsored demand-side resources for each major customer class are accounted for in the utility's load forecast and the effect, as appropriate, on its load forecast of the utility-sponsored demand-side resources on each major customer class.

(b) The utility shall compare the annual forecast of coincident peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the four years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecast in its most recently filed resource plan to the annual forecast in the current resource plan. In its initial IRP filing, the utility shall provide information demonstrating how well its forecasts during the preceding four years predicted demand.

(c) The utility shall explain and document the assumptions, methodologies, and any other inputs upon which it relied to develop its load forecast.

E. Load and resources table. The utility shall provide a load and resources table of its existing loads and resources at the time of its IRP filing. The load and resources table, to the extent practical, shall contain the appropriate components from the load forecast. Resources shall include:

(1) utility-owned generation;

(2) energy storage resources;

(3) existing and future contracted-for purchased power including qualifying facility purchases;

(4) purchases through net metering programs, as appropriate;

(5) demand-side resources, as appropriate; and

(6) other resources relied upon by the utility, such as pooling, wheeling, or coordination agreements effective at the time the plan is filed.

F. Identification of resource options.

(1) In identifying additional resource options, the utility shall consider all feasible supply-side, energy storage, and demand-side resources. The utility shall describe in its plan those resources it evaluated for selection to its portfolio and the assumptions and methodologies used in evaluating its resource options, including, as applicable: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility and efficiency of the resource.

(2) For supply-side resource options, the utility shall identify the assumptions actually used for capital costs, fixed and variable operating and maintenance costs, fuel costs forecast by year, and purchased power demand and energy charges forecast by year, fuel type, heat rates, annual capacity factors, availability factors and, to the extent feasible, emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury.

(3) The utility shall describe its existing rates and tariffs that incorporate load management or load shifting concepts. The utility shall also describe how changes in rate design might assist in meeting, delaying or avoiding the need for new capacity.

G. Determination of the most cost effective resource portfolio and alternative portfolios.

(1) To identify the most cost-effective resource portfolio, utilities shall evaluate all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis, and take into consideration risk and uncertainty (including but not limited to financial, competitive, reliability, operational, fuel supply, price volatility and anticipated environmental regulation). The utility shall evaluate the cost of each

resource through its projected life with a life-cycle or similar analysis. The utility shall also consider and describe ways to mitigate ratepayer risk.

(2) Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:

(a) load management and energy efficiency requirements;

(b) renewable energy portfolio requirements;

(c) existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions;

(d) fuel diversity;

(e) susceptibility to fuel interdependencies;

(f) transmission constraints; and

(g) system reliability and planning reserve margin requirements.

(3) Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop a reasonable number of alternative portfolios by altering risk assumptions and other parameters developed by the utility and the public advisory process.

H. Public advisory process. Public input is critical to the development and implementation of integrated resource planning in New Mexico. A utility shall incorporate a public advisory process in the development of its IRP. At least one year prior to the filing date of its IRP, a utility shall initiate a public advisory process to develop its IRP. The purpose of this process shall be to receive public input, solicit public commentary concerning resource planning and related resource acquisition issues. This process shall be administered as follows.

(1) The utility shall initiate the process by providing notice at least 30 days prior to the first scheduled meeting to the commission, interveners in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings; the utility shall at the same time, also publish this notice in a newspaper of general circulation in every county which it serves and in the utility's billing inserts; this notice shall consist of:

(a) a brief description of the IRP process;

(b) time, date and location of the first meeting;

(c) a statement that interested individuals should notify the utility of their interest in participating in the process; and

(d) utility contact information.

(2) Upon receipt of the initial notice, the commission may designate a facilitator to assist the participants with dispute resolution.

(3) The utility or its designee shall chair the public participation process, schedule meetings, and develop agendas for these meetings. With adequate notice to the utility, participants shall be allowed to place items on the agenda of public participation process meetings.

(4) Meetings held as part of the public participation process shall be noticed and scheduled on a regular basis and shall be open to members of the public who shall be heard and their input considered as part of the public participation process. Upon request, the utility shall provide an executive summary containing a non-technical description of its most recent IRP.

(5) The purposes of the public participation process are for the utility to provide information to, and receive and consider input from, the public regarding the development of its IRP. Topics to be discussed as part of the public participation process include, but are not limited to, the utility's load forecast; evaluation of existing supply- and demand-side resources; the assessment of need for additional resources; identification of resource options; modeling and risk assumptions and the cost and general attributes of potential additional resources; and development of the most cost-effective portfolio of resources for the utility's IRP.

(6) In its initial IRP advisory process, the utility and participants shall explore a procedure to coordinate the IRP process with renewable energy procurement plans and energy efficiency and load management program proposals. Any proposed procedure shall be designed to conserve commission, participant and utility resources and shall indicate what, if any, variances may be needed to effectuate the proposed procedure.

I. Action plan.

(1) The utility's action plan shall detail the specific actions the utility will take to implement the integrated resource plan spanning a four-year period following the filing of the utility's IRP. The action plan will include a status report of the specific actions contained in the previous action plan.

(2) An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.

~~[17.7.3.9 NMAC - N, 4/16/2007; A, 12-31-12, A 8/29/2017]~~

A. A public utility supplying electric service to customers shall file with the commission every three (3) years a proposed integrated resource plan (IRP) to meet the service needs of its customers over the planning period. The plan shall show the resource options the utility intends to use to meet those needs. The plan shall also specify how the implementation and use of those resource options would vary with changes in supply and demand. The utility is only required to identify a resource option type, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss any plans to reduce emissions from existing resources through sales, leases, deratings, or retirements.

B. The IRP submitted to the commission by an electric utility shall contain the utility's New Mexico jurisdictional information as follows:

(1) description of existing resources, see Appendix A;

(2) current load forecast, see Appendix A;

(3) load and resources table, see Appendix A;

(a) new load and facilities arising from special service agreements, economic development projects, and affiliate transactions;

(4) identification of resource options, see Appendix A;

(5) statement of need, see 17.7.3.10 NMAC;

(6) determination of the resource portfolio, see Appendix A; and

(7) action plan, see 17.7.3.11 NMAC.

C. The utilities shall file their IRP on a staggered schedule, as follows:

(1) Public Service Company of New Mexico shall file an IRP pursuant to 17.7.3.8 NMAC on or before September 1, 2023.

(2) Southwestern Public Service Company shall file an IRP pursuant to 17.7.3.8 NMAC on or before September 1, 2024.

(3) El Paso Electric Company shall file an IRP pursuant to 17.7.3.8 NMAC on or before September 1, 2025.

D. A multi-jurisdictional utility shall include in its IRP a description of its resource planning requirements in the other state(s) where it operates, and a description of how it is coordinating the IRP with its out-of-state resource planning requirements.

E. The utility shall promptly notify the commission and participants of material events that would have the effect of changing the statement of need or action plan had those events been recognized when the statement of need or action plan was accepted.

(1) The utility shall, within two (2) weeks of knowledge of the material event or events, submit a filing in its most recent IRP docket detailing the material events and options being considered as proposed modifications to the accepted action plan.

(2) This notice shall occur prior to the development of any proposed action plan modifications to ensure that the commission has advance notice. The utility shall serve the filing on everyone on the service list as well as each commissioner.

(3) The utility bears the burden of explaining why the events qualify as material and whether it shall file a variance, pursuant to 1.2.2.40 NMAC or 17.7.3.17 NMAC, from the accepted statement of need or action plan.

[17.7.3.8 NMAC - N, 4/16/2007; A, 12/31/2012; A 8/29/2017; A 9/14/2022]

17.7.3.9 FACILITATED STAKEHOLDER PROCESS; IRP PROCESS:

A. At least six (6) 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. The commission, aside from utility division staff and the appointed facilitator, shall not participate in the facilitated stakeholder process.

(1) The utility shall provide commission utility division staff and stakeholders who have signed a confidentiality agreement reasonable access to the same modeling software used by the utility on equal footing as the utility, and shall perform a reasonable number of modeling runs, not to exceed five (5) modeling runs per staff or a stakeholder, if requested by staff or a stakeholder, in accordance with commission precedent, and the utility shall share all modeling information.

(2) Nothing in this section shall preclude commission utility division staff from providing an analysis based on an alternative, open-source modeling software.

B. Not later than six (6) months after the facilitated stakeholder process commences, the utility shall file the IRP with the commission, explaining all resolved and unresolved issues resulting from the facilitated process.

(1) Written public comments may be filed within 30 days of the utility's filing of the IRP.

(a) Written public comments may include the commenter's own draft statement of need and action plan for commission review.

(b) Written public comments shall be made part of the utility's IRP as addendums.

(2) The utility shall file, within 60 days of the utility's filing of the IRP, a written response to all timely filed written public comments, stating whether it adopts any of the written comments as amending the IRP and the reasons why or why not.

(3) The commission's utility division staff shall consider the filed written public comments and the utility's written responses and shall file a statement with the commission within 90 days of utility's filing of the IRP as to whether the statement of need and action plan comply with the policies and procedures of this rule.

(4) If the commission has not acted within 120 days of the filing of the IRP, the statement of need and action plan are deemed accepted as compliant with this rule. If the commission determines that the statement of need and/or action plan do not comply with the requirements of this rule, the commission shall identify the deficiencies and return it to the utility with instructions for re-filing.

[17.7.3.9 NMAC - N, 9/14/2022]

~~**17.7.3.10 OBLIGATION TO NOTIFY OF MATERIAL CHANGES AND UPDATE ACTION PLAN:** The utility shall promptly notify the commission and participants of material events that would have the effect of changing the results of the utility's IRP had those events been recognized when the IRP was developed. As part of this notification, the utility shall explain how this event(s) has changed the action plan.~~

~~[17.7.3.10 NMAC - N, 4/16/2007]~~

17.7.3.10 STATEMENT OF NEED:

A. The statement of need is a description and explanation of the amount and type of new resources, expressed in terms of energy and/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 and/or 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 - N, 9/14/2022]

17.7.3.11 ACTION PLAN:

A. The utility's action plan shall:

(1) detail the specific actions the utility shall take to implement the IRP spanning a three (3) year period following the filing of the utility's IRP;

(2) detail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the Commission; and

(3) include a status report of the specific actions contained in the previous action plan.

B. The utility shall update the commission by filing two (2) reports describing the utility's implementation of the action plan. These reports shall be filed in the existing IRP docket one (1) year after the filing of the IRP, and two (2) years after the filing of the IRP, respectively.

C. An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.

D. The utility shall promptly notify the commission and participants of material events that would have the effect of changing the results of the utility's action plan had those events been recognized when the action plan was developed.

E. In accepting the action plan, the commission shall take into consideration contractual obligations as between the utility and any regional transmission organizations or balancing authorities of which the utility is a member.

[17.7.3.11 NMAC - N, 9/14/2022]

17.7.3.12 REQUEST FOR PROPOSALS PROCESS:

A. Scope and Purpose: Unless the commission grants a public utility's variance application pursuant to 17.7.3.17 NMAC for a variance from section 12 of this rule, the utility shall follow the request for proposals process to ensure cost competitiveness and fairness in procurement by comparing proposals among bidders through a transparently designed and monitored request for proposals.

B. To address the utility's procurement need, if any, as described in the statement of need, and to fulfill the objectives of the utility's action plan, the utility shall issue a request for proposals (RFP) in the current IRP docket, within five (5) months of the commission's acceptance of its statement of need and action plan.

C. Prior to the utility's commencement of an RFP solicitation, the utility shall provide the commission, the IM, and parties to the utility's pending IRP case with the documents and contracts that constitute the RFP solicitation (RFP documents) and a timeline for soliciting, accepting, evaluating, and ranking bids.

D. Within 21 days of receipt of the RFP documents, commissioners, commission utility division staff, and intervenors may submit comments to the utility, including on whether its proposed RFP conforms with its accepted statement of need and action plan and is not unduly discriminatory. Comments shall be considered, and may be incorporated, by the utility prior to the issuance of the RFP.

E. The utility may issue the RFP after comments are submitted on the independent monitor's design report pursuant to paragraph I of 17.7.3.14 NMAC. The utility shall file a notice with the commission of any final changes to the RFP design upon issuance.

F. The proposed RFP(s) shall include:

(1) bid evaluation and ranking criteria;

(2) the overall amount and duration of power the utility is soliciting and any other details concerning its resource needs;

(3) a request for bidders' reasonable estimates of any new transmission costs and transmission upgrade costs for resources, if known;

(4) the extent and degree to which resources shall be dispatchable, including the requirement, if necessary, that resources be able to operate under automatic dispatch control;

(5) the utility's proposed contract(s) for the acquisition of resources;

(6) proposed contract term lengths;

(7) the applicable discount rate;

(8) the timeline, including the solicitation period, the ranking period, and the expected selection period;

(9) all security requirements and the rationale behind them; and

(10) any other information necessary to implement a competitive RFP process.

G. For a proposed RFP, each utility shall provide:

(1) a description of information that the utility claims is confidential;

(2) descriptions of proposed protection methods for:

(a) bid prices; and

(b) other bid details.

H. Not later than 75 days after the utility receives bids for its projected needs, the utility shall provide the IM with a ranking of proposals that meet the above stated criteria, a detailed description of price and non-price criteria, its preferred portfolio of resources, along with a timeline for resource development.

I. The utility shall rank bids submitted in response to an RFP using the following price and non-price criteria:

(1) consistency with the terms and requirements of the Efficient Use of Energy Act and the Renewable Energy Act; and other public policies regarding resource preferences adopted by New Mexico or the federal government;

(2) cost of the resource that would be borne by ratepayers, described in terms of the net present value of capacity cost and/or lifetime cost of energy calculation;

(3) resource effect on system operations and reliability, credit, and financial risks to the utility;

(4) any risks imposed on ratepayers, including assessment of relative amounts of risk inherent among different technologies, fuel sources, or financing arrangements;

(5) environmental impacts including, but not limited to, those associated with resources that emit carbon dioxide and/or create long-term waste disposal issues;

(6) resource dispatchability and/or operational flexibility benefits or constraints;

(7) the utility shall include in its evaluation the estimated cost and/or environmental impact of transmission upgrades or distribution infrastructure upgrades necessary to deliver the project's energy, capacity, or services;

(a) each bidder shall be responsible for all costs associated with interconnecting its project to the transmission grid or, if applicable, to local distribution facilities; and

(8) completeness and credibility of a detailed critical path schedule, and ability to meet scheduled construction start date and commercial operational date, including completing the interconnection process.

J. Additional criteria used by the utility for ranking may not establish a preference for utility ownership or for projects proposed by a utility-affiliated company. The utility shall not unreasonably discriminate between proposals for a utility-owned or utility affiliate-owned resource and proposals for a resource owned by an independent power producer through a purchased power agreement.

K. The bid evaluation shall ensure that all bids are compared and evaluated on a consistent basis that is competitive, fair, and shall be subject to review by the commission.

L. The utility may issue additional RFPs in the current IRP docket, adhering to the processes and procedures described in 17.7.3.12 NMAC, if prudent following a material event pursuant to 17.7.3.11(D) NMAC.

M. Nothing in this rule shall be construed to prevent a public utility from procuring resources as required by the REA, NMSA 1978, Section 62-16-4 (2019), the EUEA, NMSA 1978, Section 62-17-5 (2020), or Rule 17.9.570 NMAC. Such procurements shall be included in the utility's forecasting, statement of need, and action plan.

[17.7.3.12 NMAC - N, 9/14/2022]

17.7.3.13 COST RECOVERY:

A. Acceptance of the utility's statement of need and action plan does not constitute a finding of prudence or pre-approval of costs associated with acquiring additional resources.

B. Any costs incurred to implement an accepted action plan shall be considered in a general rate case, resource acquisition proceeding, or appropriate application for a CCN.

[17.7.3.13 NMAC - N, 9/14/2022]

17.7.3.14 INDEPENDENT MONITOR:

A. Scope and Purpose: The independent monitor's role is to help the commission determine that the request for proposals design and execution is fair, competitive, and transparent. The independent monitor shall advise the commission and report on the RFP process, but the independent monitor shall not make or participate in the public utility's decisions regarding the procurement process or the selection of resources.

B. Following commission acceptance of a public utility's statement of need and action plan, the commission shall appoint an independent monitor to monitor the procurement process of a public utility for competitive resource procurements pursuant to 17.7.3.12 NMAC. The independent monitor, as provided in this section, shall assist the commission in ensuring that all such processes are reasonable and competitively fair and shall report to the commission regarding those matters as provided in this rule. The commission may appoint an IM for emergency procurements pursuant to 17.7.3.17 NMAC.

C. The commission shall, through its designee:

(1) undertake a process consistent with state purchasing rules and commission policies in recommending a pool of qualified IMs;

(2) develop an RFP, including the scope, terms of work, and evaluation process to score the RFP responses;

(3) receive, review, score, and rank the RFP responses;

(4) confer with the public utility on the recommendation of the IM;

(5) recommend qualified bidders to the commission for appointment as the IM; and

(6) administer the contract with the appointed IM, including: confirming that contract deliverables are met, reviewing invoices and related contract performance, and approving utility invoices after staff's review and approval.

D. In selecting the IM, the commission, through its designee, may solicit recommendations of the names of independent firms or individuals that demonstrate independence from public utilities supplying electric service in the state, their affiliates, and likely bidders, and demonstrate the qualifications, expertise, and experience to perform the functions of an IM as provided in this rule.

(1) The IM shall provide a statement of interest to the commission which discloses any contracts or other economic arrangements of any kind between the IM and any investor-owned electric utility or affiliate within the last four (4) years.

(2) The IM shall notify the commission and utility of any perceived or actual conflicts that arise during the course of the procurement process.

E. The commission, through its designee, shall develop a standard form of contract between an IM and the commission that requires the IM to perform the functions of an IM as provided in this rule in a manner that is not subject to the control of the public utility. The standard form of contract between an IM and the commission for IM services as provided for in this rule shall include, but shall not be limited to, the identification of the IM's functions and scope of work as provided in paragraph G of 17.7.3.14 NMAC.

F. Funding for the services of the IM shall be paid by the utility and treated as a regulatory asset to be recovered through rates established in the utility's next general rate proceeding.

G. Duties of the Independent Monitor

(1) The IM shall file a minimum of two reports with the Commission. The first report shall analyze the RFP design (design report). The final report shall review the fairness of the RFP execution (final report).

(a) In the design report, the IM shall report to the commission on RFP design within 28 days of the public utility's provision of RFP documents pursuant to 17.7.3.12(C) NMAC. The IM shall analyze the proposed RFP, including but not limited to its scope, instructions, conditions for eligible proposals, specifications, time schedules, disclosure of bid evaluation methods, and term sheets. The RFP design report shall state whether the contents of the proposed RFP comply with the requirements of 17.7.3.10 through -12 NMAC and are otherwise reasonable, competitively fair, designed to promote a robust bid response, and designed to identify a utility's most cost-effective option among resource alternatives to meet its service needs in compliance with this rule.

(b) In the final report, the IM shall, within 30 days of the utility's submission of its shortlist to the IM, review and report on the reasonableness, competitiveness, and fairness of the utility's solicitation, evaluation, and procurement processes, including but not limited to bid screening, comparison, ranking evaluation, and short-listing criteria.

(i) The IM shall state whether the RFP process implemented by the public utility complied with the requirements of 17.7.3.11 NMAC and 17.7.3.12 NMAC.

(ii) The IM's report shall also provide summary information on the results of the bids, including the number of bids sorted by the following criteria: by resource type, capacity and/or energy, price range by resource type, and whether there were any deficiencies in those respects that should be addressed by the commission in a future proceeding for approval of the solicited projects. The commission may rely on that opinion to request that the utility make modifications in a timely manner.

(2) At any point during the public utility's RFP process the IM may notify the commission and the utility of any deficiency as contemplated in paragraph G of 17.7.3.14 NMAC.

H. The public utility shall provide the IM with prompt and continuing access to all documents, data, assumptions, models, specific model inputs, bidding and weighting criteria used, and any other relevant information reviewed, produced, or relied on by the public utility in the preparation and conduct of its competitive resource procurement process.

I. All communications, including but not limited to reports pursuant to this section, provided by the IM to the commission, shall be made part of the commission's public records in a timely manner in the public utility's most recent IRP docket.

(1) The public utility, commission utility division staff, and any parties to the public utility's most recent IRP docket may comment within 14 days of the filing of the design report to the public record. After the design report comment deadline of 14 days, the utility may issue the RFP.

(2) In any proceeding filed by a public utility for approvals stemming from its solicitation made pursuant to the RFP process as described in 17.7.3.12 NMAC, the commission may rely upon any reports or findings of the IM assigned to monitor that solicitation as evidence, provided that such evidence shall not be conclusive as to whether or not a resource proposed by the utility shall be approved.

J. All communications between the public utility and any bidders shall be shared at the same time with the IM. Commission utility division staff and any parties are restricted from initiating contacts with the independent monitor. The independent monitor may initiate contact with the utility, commission utility division staff, and any parties.

(1) For all contacts with the public utility, commission utility division staff, and any parties in the resource plan proceeding, the independent monitor shall maintain a log that briefly identifies the entities communicating with the IM, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(2) The communications log shall be contained in the IM's report to the commission pursuant to paragraph G(1)(b) of 17.7.3.14 NMAC.

K. The independent monitor shall serve as an advisor to the commission and shall not be a party to the proceedings in accordance with 1.2.3.9 NMAC. As such, the independent monitor shall not be subject to discovery nor cross-examination at hearing, if one is held, but the public utility, commission utility division staff, and any parties shall have the opportunity to respond to any reports or findings of the IM pursuant to 17.7.3.14(I)(1) NMAC.

L. The commission shall not appoint an independent monitor for a utility's procurement for which the commission grants a variance pursuant to paragraph D of 17.7.3.17 NMAC.

[17.7.3.14 NMAC - N, 9/14/2022]

17.7.3.15~~1~~ CONFIDENTIALITY OF INFORMATION: ~~The utility may submit any portions of its IRP under seal to the extent the utility deems specific information to be confidential. The utility shall seek a protective order under Subsection B of 17.1.2.8 NMAC for those portions of its IRP it considers confidential, and the utility shall have the burden of proving its right to such protection. Any information submitted under seal pursuant to this paragraph shall remain under seal for a period of two years, after which time it shall become public unless the utility seeks and obtains further protection from the commission. Information submitted under seal shall be available for review by the commission and its designated representatives and by any person who has entered into a confidentiality agreement with the utility in a form approved by commission order.~~

~~[17.7.3.11 NMAC - N, 4/16/2007; A, 8/29/2017]~~

A. The utility may submit any portions of its IRP under seal to the extent the utility deems specific information to be confidential.

B. The utility shall seek a protective order under paragraph B of 17.1.2.8 NMAC for those portions of its IRP it considers confidential, and the utility shall have the burden of proving its right to such protection.

(1) Any information submitted under seal pursuant to this paragraph shall remain under seal for a period of three (3) years, after which time it shall become public unless the utility seeks and obtains further protection from the commission.

(2) Information submitted under seal shall be available for review by the commission and its designated representatives and by any person who has entered into a confidentiality agreement with the utility in a form approved by commission order, provided, however, that bidders or potential bidders shall not have access to competitively sensitive information of other bidders.

C. The utility shall not disclose any bid information for which a non-winning bidder has requested confidential treatment except in accordance with a commission protective order limiting disclosure of such information to persons who execute and file a confidentiality agreement with the commission as provided in that order.

[17.7.3.15 NMAC - N, 4/16/2007; A, 8/29/2017; A, 9/14/2022]

~~**17.7.3.12 COMMISSION REVIEW, ACCEPTANCE AND ACTION:** The commission will review the utility's proposed IRP for compliance with the procedures and objectives set forth herein. Written public comments may be filed within 20 days of the utility's filing of the proposed IRP in support or in opposition of the proposed IRP as filed. The utility shall file, within 40 days of the utility's filing of the proposed IRP, a written response to all written public comments that were timely filed in support or in opposition, stating whether or not it will incorporate any of the written comments into its proposed IRP and state its reasons why or why not. The commission's utility division staff shall review the utility's proposed IRP as filed and shall consider the filed written public comments in support or in opposition and the utility's written response and shall file a written recommendation to the commission within 60 days of utility's filing as to whether or not the IRP complies with the procedures and objectives of this rule and whether or not it recommends that the commission accept the proposed IRP as filed. If the commission has not acted within 90 days after the filing of the proposed IRP, that IRP is deemed accepted as compliant with this rule. If the commission determines the proposed IRP does not comply with the requirements of this rule, the commission will identify the deficiencies and return it to the utility with instructions for re-filing.~~

~~[17.7.3.12 NMAC - N, 4/16/2007; A, 8/29/2017; A, 01/30/2018]~~

~~**17.7.3.13 ADDITIONAL INVESTIGATIONS AND INFORMATION:** The commission may conduct an investigation of any matters pertaining to a public utility's IRP where it deems appropriate and may require additional information to be filed.~~
~~[17.7.3.13 NMAC - N, 4/16/2007]~~

17.7.3.164 EXEMPTIONS:

A. Motion for Exemption from Rule: ~~-~~ Upon motion by a utility and for good cause shown, the commission may exempt public utilities with fewer than five thousand customers and distribution-only public utilities from the requirements of this rule.

B. Multi-State Resource Planning: ~~-~~The commission shall take into account a public utility's resource planning requirements in other states and shall authorize utilities that operate in multiple states to implement plans that coordinate the applicable state resource planning requirements.

[17.7.3.14 NMAC - N, 4/16/2007; A, 9/14/2022]

17.7.3.175 VARIANCES AND AMENDMENTS: ~~A utility may file a request for a variance from the requirements of this rule. Such application shall describe the situation which necessitates the variance; set out the effect of complying with this rule on the utility and its customers if the variance is not granted; identify the section(s) of this rule for which the variance is requested; describe the expected result which the request will have if granted; and state how the variance will aid in achieving the purposes of this rule. The commission may grant a request for a procedural variance through an order issued by the chairman, a commissioner or a designated hearing examiner. Other variances shall be presented to the commission as a body for determination.~~
~~[17.7.3.15 NMAC - N, 4/16/2007]~~

A. A utility may file a request for a variance from the requirements of this rule.

B. Such application shall:

(1) describe the situation which necessitates the variance;

(2) set out the effect of complying with this rule on the utility and its customers if the variance is not granted;

(3) identify the section(s) of this rule for which the variance is requested;

(4) describe the expected result which the request shall have if granted; and

(5) state how the variance shall aid in achieving the purposes of this rule.

C. The commission may grant a request for a procedural variance through an order issued by the chair, a commissioner, or a designated hearing examiner.

D. The following types of procurements that deviate from the utility's Commission-accepted action plan shall be submitted to the commission as an application for a variance pursuant to 17.7.3.17 NMAC:

(1) emergency procurements;

(2) capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of 20 megawatts or less;

(3) capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for a two (2) year term or less (including renewal terms) or for 20 megawatts of capacity or less;

(4) improvements or modifications to existing utility generation facilities that change the production capability of the generation facility site in question by 20 megawatts or less based on the utility's share of the total power generation at the facility site and that have an estimated cost of $20 million or less;

(5) interruptible service provided to the utility's electric customers;

(6) modification to, or amendment of, existing power purchase agreements provided that the modification or amendment does not extend the agreement more than four (4) years, does not add more than 20 megawatts of nameplate capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility; and

(7) utility administered demand-side programs.

[17.7.3.17 NMAC - N, 4/16/2007; A, 9/14/2022]

HISTORY of 17.7.3 NMAC:

Pre-NMAC History: The material in this part was derived from that previously filed with the state records center and archives under:

Public Service Commission, NMPSC Rule 420, Energy Conservation Programs For Electric and Gas Utilities, filed 06-30-1988.

History of Repealed Material: NMPSC Rule 420, Energy Conservation Programs For Electric and Gas Utilities (filed 06-30-1988) repealed 4/16/2007.

Other History:
Only that applicable portion of NMPSC Rule 420, Energy Conservation Programs For Electric and Gas Utilities (filed 06-30-1988) was renumbered, reformatted and replaced by 17.7.3 NMAC, Integrated Resource Plans for Electric Utilities, effective 4/16/2007.

STAKEHOLDER QUESTIONS 20230504

Offered by Barbara Chatterjee, Community Member, prior to March 28, 2023, Stakeholder Meeting.

Question: What is the relationship between PNM and PNMR and what is the role of each in the IRP process and implementation?

Response: PNM is a wholly owned subsidiary of PNM Resources. PNM is a regulated utility subject to the rules and procedures of the New Mexico Public Regulation Commission. The IRP rule applies only to PNM, not PNM Resources. PNM Resources is a publicly traded company not directly subject to the regulatory oversight of the NMPRC. PNM is responsible for developing the IRP and must make filings and gain approval from the NMPRC to acquire any resources subject to the NMPRC's Certificate of Convenience and Necessity ("CCN"), Power Purchase Agreement ("PPA"), and other applicable rules.

Question: What PNMR businesses are within or outside the IRP process? What percentage of PNMR are in each of these categories?

Response: The only business subject to the IRP rule is PNM.

Question: Does anything in the non-regulated sector impact PNM's planning and/or operations? If so, how?

Response: Many things in unregulated sectors impact PNM's planning and operations, such as the price for new resources, the cost of natural gas, the cost of capital, regional markets, and other factors – all are not regulated by the NMPRC. Most all the fundamental drivers in the planning and operations process are things beyond PNM's and the NMPRC's direct control. PNM plans in uncertain environments to best meet its customer's needs. PNM's rates, procurements and operations are regulated by the NMPRC.

Question: How do unregulated activities relate to the IRP process?

Response: See response to the previous question.

Question: What are the PRC's objectives and expectations for the IRP process?

Response: The NMPRC IRP rule provides for its objectives.

Question: In the revised IRP rule 17.7.3.1 NMAC of 10/27/2022, which parts are new and which carry over from before? A table showing the changes could be helpful.

Response: Please find attached Exhibit B which is a redline of the previous rule to the new rule which was filed in the IRP Rulemaking Docket

Question: Where are the stakeholders defined in the new Rule?

Response: Stakeholder is not a defined term in NMAC 17.7.3

Question: How do the commission or PNM know when the enough varied stakeholders are participating to meet requirements?

Response: The facilitated stakeholder process that is currently being conducted by Gridworks has been sent to a very broad group determined by the facilitated stakeholder.

Question: What happens if no stakeholders can be enlisted from a given key sector?

Response: The Commission determined in its rulemaking that the Commission appointed stakeholder process is appropriate to receive public input to the IRP.

Question: How does the Statement of Need relate to PNM's business plan and operations?

Response: The Statement of Need defines requirements that PNM must meet in the future; however, prior to pursuing any new resources, PNM must seek subsequent approvals from the NMPRC through filings for a CCN, PPA or other applicable approvals. Therefore, the Statement of Need outlines a high-level roadmap for future procurements and investments by PNM, but actual outcomes may vary when specific market bids are sought to inform procurement analyses and filings.

Question: Is the Independent Monitor for RFP's a new element under 17.7.3?

Response: Yes

Question: Under 17.7.3.12.F (4) What is meant by "resources be able to operate under automatic dispatch control"?

Response: Resources that have Automatic Generation Control (AGC) can follow a dispatch signal sent by the remote system operator to vary its output to a desired set point.

INTERWEST ENERGY ALLIANCE

May 1, 2023
Electronically Submitted to info@gridworks.org and dshields@gridworks.org

Deborah Shields
Communications and Operations Director
Gridworks

Dear Gridworks Team:

Interwest Energy Alliance submits the attached information for consideration at the May 4th in-person workshop being held in Albuquerque, NM. Due to travel and other issues, Interwest is unable to attend the meeting, but hoped to provide some information for consideration.

For discussion within the statement of need, candidate resource and modeling input discussions, we have attached three documents.

- A whitepaper that Interwest and NMAREA submitted in the 2021 IRP, authored by Michael Goggin of Grid Strategies. Several broad areas of concern remain relevant in this IRP process:
  - Synergies between wind, solar, and storage must be accurately modeled.
  - Fossil resources are modeled as more reliable than is warranted.
  - Market availability and transmission interconnections must be adequately considered.
- A presentation that Interwest provided to the IRP public advisory process on August 17, 2022 by Michael Goggin.
  - This presentation focused on correlated outages of fossil generators and how to accurately account for and model this concern.
- Written comments that Interwest provided within the IRP public advisory process on September 7, 2022.
  - These written comments focused on the benefits of transmission expansion for PNM and its customers, and how transmission should be treated in the IRP how to accurately account for and model this concern so that resource selection includes all known costs and benefits on a level playing field.

Interwest appreciates the opportunity to provide this information. Interwest has been an active participant in the IRP process and looks forward to upcoming meetings on key issues.

Thank you again for your outreach efforts in your IRP planning process and willingness to consider participant input. We welcome the opportunity to engage in discussions on these and other key IRP issues to assist PNM in developing a strong and well supported IRP.



Sincerely,

Chris Leger
Staff Attorney
chris@interwest.org

Attachments

Analytical Review of PNM's IRP

Michael Goggin, Grid Strategies LLC

Prepared for Interwest Energy Alliance and New Mexico Affordable Reliable Energy Alliance

September 2021



Table of Contents

I. Summary **2**

II. Reliability

A. PNM did not account for the synergies among new wind, solar, and storage resources for meeting capacity needs 4

B. PNM overstates load growth, and thus the need for combustion turbines..... 12

C. PNM does not account for the reliability risks of fossil resources 15

D. PNM understates the availability of market purchases..... 17

III. Economics

A. Cost assumptions for renewables and storage are too high 26

B. PNM makes the risky assumption that alternative fuels for combustion turbines will be economic and available by 2040..... 28

C. Reliability and economic assumptions caused PNM to choose the wrong resource additions 31

I. Summary

As a result of questionable modeling assumptions, PNM's 2020-2030 Integrated Resource Plan ("IRP") misses opportunities to more cost-effectively serve customers with larger amounts of renewable and storage resources, while also overstating the value of new combustion turbines. Fortunately, these problems can be corrected by implementing the recommendations provided in this report. This will allow PNM to better serve its ratepayers with more cost-effective and reliable power by building a portfolio with larger amounts of renewable and storage resources and no combustion turbines.

This report first addresses PNM's reliability assumptions that cause it to overstate the need for combustion turbines. First, PNM did not account for the large synergies among wind, solar, and storage resources for meeting capacity needs, which compounds with other assumptions to significantly underbuild these resources while overbuilding combustion turbines. Second, PNM continues its historical trend of significantly overestimating future load growth. Third, PNM makes a number of questionable assumptions in modeling fossil resources, including failing to account for the risk of the correlated failure of gas generators. Finally, PNM significantly understates the contribution of imports to meeting its capacity needs.

This report next addresses unusual economic assumptions in PNM's IRP. First, PNM overstates the cost of renewable and storage resources. Second, the report discusses the major economic and reliability risks and uncertainties associated with PNM's assumption that it can rely on alternatives fuels such as hydrogen being available at a reasonable cost for its combustion turbines. Finally, the report explains

how with more reasonable economic and reliability assumptions for wind, solar, storage, and imports, PNM could have developed a "no new combustion" portfolio that is superior to its "technology neutral" portfolio that adds risky and uneconomic combustion turbines.

The following table summarizes the modeling concerns, their impact on PNM's modeling, and recommendations for how to address those concerns. In total, PNM appears to be significantly overstating capacity needs in the near term, and by over 1,000 MW by the later years of the analysis. Moreover, fixing any one of the following three assumptions is alone sufficient to entirely offset the claimed need for 280 MW of combustion turbines: accounting for diversity benefits, correcting for the biased load growth forecast, or accounting for the availability of market imports. If these assumptions were fixed, PNM's "technology neutral" scenario would look more like its "no new combustion" scenario.

Table 1: Summary of Modeling Assumption Concerns

Modeling Assumption Concern	Impact	Solution
Reliability Issues		
Misses diversity benefits among wind, solar, and storage	Understated ELCC of renewable and storage by hundreds of MWs	Use SERVM to iteratively assess ELCC of many portfolios
Overestimates load growth	Overstates 2040 load in the range of 720 MW	Correct load forecast bias
Misses risk of fossil outages	Understates reliability risk of increasing gas dependence with new combustion turbines	Account for risk of correlated outages reducing fossil ELCC
Underestimates market imports	Reduces need for capacity by several hundred MWs	Use historical data of PNM imports during periods of high demand and high prices
Economic Issues		
Overstate renewable costs	Biased modeling against selecting renewable resources	Use NREL standard cost assumptions, make transmission cost assumptions transparent
Cost of alternative fuels is high and availability uncertain	PNM customers exposed to economic and reliability risks if alternative fuels do not materialize	Account for these risks when weighing investment in combustion turbines that may become a stranded asset

II. Reliability

A. PNM did not account for the synergies among new wind, solar, and storage resources for meeting capacity needs

In several footnotes, PNM admits that it did not account for synergies among the capacity value contributions of wind, solar, and storage resources when optimizing generation expansion solutions in EnCompass, its modeling software used to develop resource portfolios. Capacity value, or Effective Load Carrying Capability ("ELCC"), refers to the contribution of a resource to meeting electricity demand during periods of peak net load. As a result, this error not only greatly overstates the need for new capacity resources, like the proposed combustion turbines, but it also strongly biases the economic selection of new resources against wind, solar, and storage. At the high renewable and storage penetrations studied in PNM's analyses, failing to account for these synergies likely understates their contributions to capacity by many hundreds of MWs. In a footnote on page 54 PNM admits it did not capture the synergistic effects for new wind, solar, and storage resources' capacity value:[1]

We fully account for these synergistic interactive effects among our existing resources (including the SJGS Replacement Resources) as described in Appendix M; however, as discussed in more detail in Section 5.4.1 (EnCompass), our current modeling framework does not allow us to capture this effect yet when producing long-term capacity expansion results.

In Section 5.4.1., PNM further explains that while it modeled the declining ELCC of individual resources, it did not capture offsetting synergies among these resources:[2]

Another key feature of Encompass for our 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 our ability to optimize a portfolio while meeting resource adequacy needs.

Currently, EnCompass does not include logic to capture the synergistic effects between resources explicitly. However, PNM understands this functionality may be added in future releases of the software.

In footnote 28 on that page, PNM further explains:

The effect of not capturing the synergies embeds some conservatism into the portfolios and increases resource adequacy approximation resulting from the EnCompass simulations. As shown in Section 8.4 and Appendix M, the near term LOLE analysis (2025) yields results very close to the calibrated 0.2 metric. However, the 2040 LOLE analysis results in portfolios well below the 0.2 threshold. One potential reason for this is the implicit diversity benefit captured in the SERVM model that is not captured by EnCompass.

However, not capturing the synergies among wind, solar, and storage resources does more than just embed some conservatism into PNM's analysis. It drastically understates the ELCC of wind, solar, and storage, particularly at the high renewable penetrations studies in PNM's analysis. Those understated ELCCs are then input directly into the EnCompass economic optimization, making wind, solar, and

[1] See footnote 23, IRP at 54.
[2] IRP at 81.

storage far less attractive to EnCompass as it optimizes to most cost effectively meet electricity demand needs. This is particularly true for PNM's analysis, as EnCompass's capacity expansion decisions seem to be almost entirely driven by the need to meet demand, as evinced by the model's addition of capacity resources like batteries and combustion turbines instead of energy resources.

As PNM notes, "the 2040 LOLE analysis results in portfolios well below the 0.2 threshold. One potential reason for this is the implicit diversity benefit captured in the SERVM model that is not captured by EnCompass." The magnitude of the diversity benefit that PNM is not accounting for can be inferred by how much the 2040 LOLE results fall below the 0.2 target threshold. Astrape's analysis shows that, even with the highly conservative assumption that only 50 MW of imports are available during peak net load hours, all eight technology neutral and no new combustion scenarios studied have LOLEs of 0.06 or less, and five of the eight come in below 0.02.[3] This indicates these five scenarios are ten times more reliable than the target reliability threshold. Without new SERVM runs, it is not possible to directly translate that LOLE into a quantification of how many surplus MW EnCompass built in those scenarios due to the failure to account for the diversity benefits among wind, solar, and storage, but the magnitude of the unaccounted-for diversity benefit in PNM's analysis is clearly very large. For reference, in the extensive SERVM modeling runs conducted as part of the San Juan replacement resources case, New Mexico Public Regulation Commission ("PRC") Case No. 19-00195-UT, each 25 MW of additional capacity tended to reduce LOLE by about .01.[4] Based on this, one could roughly infer that a scenario that came in at 0.02 LOLE instead of 0.2 LOLE would have in the range of 450 MW of surplus capacity under the simplistic assumption that LOLE declines linearly with the addition of capacity.[5] As a result, it appears that in its current IRP modeling, PNM understated the capacity contribution of wind, solar, and storage, and overstated the need for new capacity, by many hundreds of MWs.

The capacity value for each wind, solar, and storage resource changes drastically based on the penetration of the other two resources on the power system. Due to diversity benefits among wind, solar, and storage resources, their combined capacity value is much greater than the sum of their parts. The capacity value of wind increases with more solar on the power system, and vice versa, because their output patterns are negatively correlated on a daily and seasonal basis. For example, the PJM grid operator's renewable integration study showed wind provided a higher capacity value when the resource mix had more solar generation, and vice versa.[6] Public Service Company of Colorado found a similar trend in a 2016 wind effective load carrying capability study.[7]

[3] Appendix M at 38.
[4] See the LOLE results in PNM Exhibit NW-2 to Nick Wintermantel's testimony in Case No. 19-00195-UT, available at https://www.pnmforwardtogether.com/assets/uploads/replacement-plan-filing-july2019/43_Nick_Wintermantel.pdf.
[5] Taking 0.2 – 0.02 = 0.18, and .18/.01 = 18, and 18 times 25 MW = 450 MW.
[6] General Electric International, Inc., *PJM Renewable Integration Study: Task 3A Part F, Capacity Valuation* at 29 (Mar. 31, 2014), *available at* https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-f-capacity-valuation.ashx?la=en.
[7] Hearing Exhibit 103, Attach. KLS-2, An Effective Load Carrying Capability Study of Existing and Incremental Wind Generation Resources on the Public Service Company of Colorado System, Docket No. 16A-0369E (Colo. Public Utility Comm'n May 27, 2016), *available at* https://www.xcelenergy.com/staticfiles//xe/PDF/Attachment%20KLS-2.pdf.

Adding battery storage helps keep the capacity value of wind and solar high, as battery storage can absorb wind and solar output when it is less valuable and shift it later in time to peak net load periods.[8] In particular, adding storage keeps solar capacity value high by making it possible to shift midday and early afternoon solar output to later in the afternoon and evening. Similarly, battery storage can shift overnight and morning wind output to help meet evening peak net load, or morning demand during winter periods when heating demand is high and solar output is low.

Less intuitively, solar also boosts the capacity value of storage. Solar output in the late afternoon and early evening helps shift peak net load later into the evening. This also shortens the duration of the peak net load period, allowing limited duration storage resources to fully meet the peak demand. As shown in the chart from utility industry consultant E3 shown below, the diversity benefit between solar and storage causes their combined ELCC to be greater than the sum of their parts.[9]

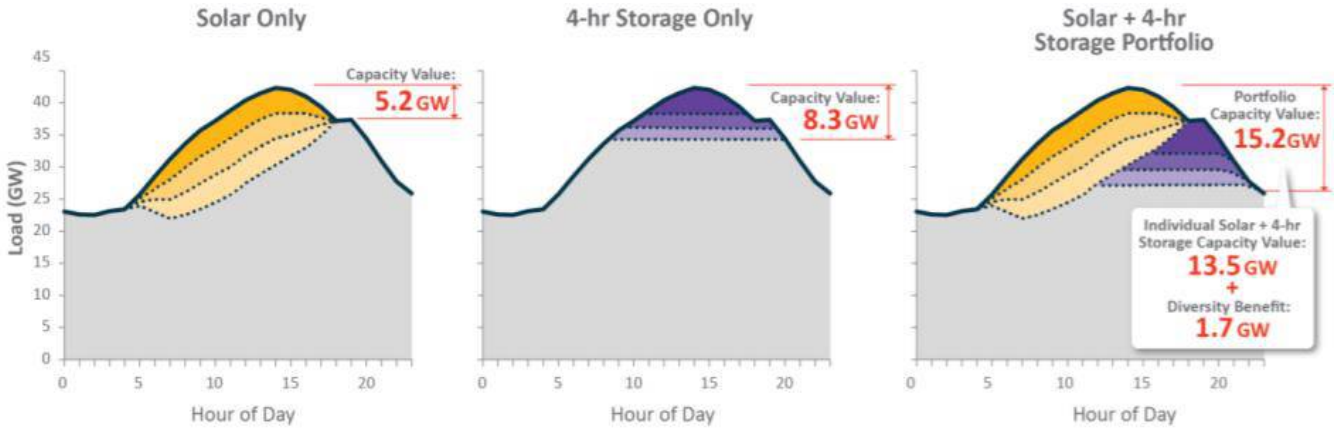


Figure 1: E3 chart showing complementary capacity value benefit between solar and storage

Solar's impact on storage's capacity value can be quite large. NREL has found that across the Southwest Reserve Sharing Group ("SRSG"), of which PNM is a member, the quantity of storage that provides 100% capacity value increases from around 1,200-1,500 MW at a 5% solar penetration, to around 5,000 MW at a 35% solar penetration.[10] Notably, PNM has proposed achieving a solar penetration of over 50% by 2040,[11] indicating PNM could expect to see something like this four-fold increase in the amount of storage that provides full capacity value if it had accounted for increases in storage's capacity value from solar capacity additions. Given PNM's analysis showing that 4-hour storage's marginal capacity value drops below 95% between 300 MW and 500 MW,[12] one could roughly extrapolate that 1,200 MW of storage could provide nearly full capacity value if PNM accounted for the synergies between solar and storage.

[8] Andrew Mills & Ryan Wiser, LBNL, *Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels* (Mar. 2014), *available a*t https://emp.lbl.gov/sites/all/files/lbnl-6590e.pdf.
[9] Nick Schlag, et al., *Capacity and Reliability Planning in the Era of Decarbonization* at 6 (Energy and Environmental Economics Aug. 2020), *available at* https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.
[10] https://www.nrel.gov/docs/fy19osti/74184.pdf, at 12.
[11] IRP at 142.
[12] Appendix M at 30.

The complementary diversity benefit among wind, solar, and storage increases notably as power systems reach higher renewable and storage penetrations because capacity needs shift to periods when existing resources are unable to produce. Given the very large solar or storage capacity additions PNM evaluated, ranging from 1,200-2,500 MW of solar or 500-1,500 MW of battery capacity, PNM likely understated the ELCC contributions of wind, solar, and storage additions by hundreds of MWs by not accounting for these synergies, as quantified above. Most of that value was likely due to missed complementarity between solar and storage. PNM found only a 6.6% marginal capacity value for solar capacity additions going forward, and a storage capacity value that drops off dramatically with larger amounts of storage capacity.[13] Even slight boosts to solar and storage ELCCs would provide PNM with many hundreds of MWs of additional capacity value, eliminating the need for near-term combustion turbine capacity additions and making those additions less economically attractive than solar, wind, and storage additions.

In addition to failing to account for synergies between solar and storage, PNM also missed increases in the capacity value of wind at higher solar and storage penetrations. Because of their negatively correlated output profiles, solar's capacity value would presumably also significantly increase with higher wind penetrations. The SERVM modeling of the base portfolio with 1,026 MW of solar, 300 MW of storage, and 607 MW of wind shows an ELCC of 28.9% for the 607 MW of currently installed wind. Presumably due to the high level of solar and storage in the base portfolio, this 28.9% ELCC for wind is roughly twice what is typically calculated for wind resources, particularly for PNM's relatively high wind penetration.[14] This is because the output profile for PNM's existing wind is almost perfectly negatively correlated with its solar profile, as shown below.[15]

Figure 52. Historical average capacity factor by month and time of day for PNM's solar resources (2013-2019)

Month	Hour of Day (MST)																							
	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%	0%	0%	0%	0%	2%	32%	57%	69%	74%	75%	70%	62%	46%	16%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	12%	45%	67%	77%	80%	79%	78%	71%	57%	33%	3%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	2%	29%	58%	75%	83%	84%	83%	81%	73%	61%	41%	11%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	14%	46%	64%	78%	85%	86%	85%	81%	74%	61%	44%	18%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	3%	25%	53%	68%	81%	87%	87%	86%	82%	74%	61%	46%	24%	3%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	4%	28%	52%	67%	81%	88%	89%	86%	81%	72%	60%	46%	26%	5%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	2%	22%	48%	65%	78%	85%	86%	83%	77%	68%	55%	40%	22%	4%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	11%	41%	62%	76%	84%	85%	82%	78%	68%	54%	38%	17%	1%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	8%	41%	61%	75%	83%	84%	82%	79%	69%	55%	35%	8%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	2%	33%	59%	73%	80%	80%	79%	75%	67%	51%	22%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	18%	47%	63%	70%	72%	71%	68%	59%	40%	8%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	4%	33%	56%	65%	69%	69%	66%	57%	36%	6%	0%	0%	0%	0%	0%	0%	0%

[13] *Id.*

[14] See, for example, MISO's wind ELCC of 16.3%, https://cdn.misoenergy.org/DRAFT%202021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf and PJM's wind ELCC of 15% https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2024-bra.ashx, which themselves are high relative to other power systems.

[15] IRP at 106.

Figure 50. Historical average capacity factor by month and time of day for PNM's wind resources (2013-2019)

Month	Hour of Day (MST)																							
	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	33%	32%	33%	33%	32%	32%	32%	31%	29%	28%	28%	30%	31%	32%	33%	34%	34%	35%	37%	38%	38%	38%	36%	35%
2	39%	38%	38%	36%	35%	35%	33%	31%	27%	28%	29%	32%	35%	39%	41%	42%	43%	41%	41%	41%	42%	41%	41%	39%
3	38%	36%	34%	33%	33%	32%	29%	26%	27%	28%	29%	30%	33%	35%	36%	39%	41%	41%	40%	41%	41%	41%	40%	40%
4	36%	37%	35%	34%	32%	30%	28%	26%	27%	27%	29%	32%	35%	37%	39%	42%	44%	43%	40%	42%	45%	44%	44%	40%
5	34%	32%	31%	29%	25%	22%	19%	19%	19%	20%	22%	25%	27%	31%	34%	35%	36%	38%	36%	36%	38%	39%	39%	37%
6	33%	31%	28%	25%	24%	21%	17%	16%	14%	14%	14%	15%	17%	20%	21%	24%	25%	27%	28%	29%	33%	34%	34%	36%
7	24%	22%	21%	20%	19%	17%	14%	12%	12%	11%	10%	10%	11%	12%	14%	17%	20%	21%	24%	25%	27%	27%	26%	24%
8	21%	19%	19%	19%	18%	16%	13%	11%	10%	10%	10%	9%	10%	12%	13%	16%	19%	21%	21%	22%	24%	25%	24%	23%
9	23%	21%	20%	18%	17%	17%	16%	14%	14%	14%	15%	16%	17%	19%	21%	24%	24%	23%	24%	28%	30%	29%	28%	26%
10	29%	28%	27%	27%	25%	25%	25%	22%	21%	23%	24%	26%	28%	30%	31%	33%	33%	32%	33%	35%	35%	34%	32%	31%
11	34%	33%	32%	31%	30%	30%	30%	29%	27%	28%	30%	31%	34%	35%	37%	37%	35%	34%	36%	37%	38%	37%	36%	34%
12	33%	32%	32%	31%	31%	31%	30%	30%	27%	26%	26%	27%	29%	31%	33%	33%	31%	33%	36%	36%	35%	35%	34%	33%

Figure 2: Historical hourly and monthly solar and wind capacity factors, from PNM's IRP

Combining the above wind and solar profiles results in a balanced portfolio that provides high levels of generation during peak load and net load hours. The following chart shows that, at a ratio of 75% wind capacity and 25% solar capacity, the wind and solar profiles complement each other to, on average, provide generation day and night and across the seasons. Battery resources and imports can help fill in during time periods of low output, which are of much shorter duration with a mix of wind and solar resources.

Month	Hour of Day (MST)																							
	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	25%	24%	25%	25%	24%	24%	24%	24%	30%	35%	38%	41%	42%	42%	40%	37%	30%	26%	28%	29%	29%	29%	27%	26%
2	29%	29%	29%	27%	26%	26%	25%	26%	32%	38%	41%	44%	46%	49%	49%	46%	41%	32%	31%	31%	32%	31%	31%	29%
3	29%	27%	26%	25%	25%	24%	22%	27%	35%	40%	43%	44%	46%	47%	45%	45%	41%	34%	30%	31%	31%	31%	30%	30%
4	29%	28%	27%	26%	24%	23%	25%	31%	36%	40%	43%	46%	48%	48%	48%	47%	44%	37%	30%	32%	34%	33%	33%	30%
5	26%	24%	23%	22%	19%	17%	21%	28%	31%	35%	38%	41%	42%	44%	44%	42%	39%	35%	28%	27%	29%	29%	29%	28%
6	25%	23%	21%	19%	18%	17%	20%	25%	27%	31%	33%	34%	34%	35%	34%	33%	30%	27%	22%	22%	25%	26%	26%	27%
7	18%	17%	16%	15%	14%	13%	16%	21%	25%	28%	29%	29%	29%	28%	28%	27%	25%	21%	19%	19%	20%	20%	20%	18%
8	16%	14%	14%	14%	14%	12%	13%	19%	23%	27%	29%	28%	28%	29%	27%	26%	24%	20%	16%	17%	18%	19%	18%	17%
9	17%	16%	15%	14%	13%	13%	14%	21%	26%	29%	32%	33%	33%	34%	33%	32%	27%	19%	18%	21%	23%	22%	21%	20%
10	22%	21%	20%	20%	19%	19%	19%	25%	31%	36%	38%	40%	41%	41%	40%	38%	30%	24%	25%	26%	26%	26%	24%	23%
11	26%	25%	24%	23%	23%	23%	23%	26%	32%	37%	40%	41%	43%	43%	43%	38%	28%	26%	27%	28%	29%	28%	27%	26%
12	25%	24%	24%	23%	23%	23%	23%	24%	29%	34%	36%	38%	39%	40%	39%	34%	25%	25%	27%	27%	26%	26%	26%	25%

Figure 3: PNM average capacity factor by month and time of day for a portfolio of 75% wind and 25% solar capacity (2013-2019)

However, because PNM did not account for the impact of solar and storage additions when evaluating the capacity value of wind additions, it found only a 10.7% ELCC for around 400 MW of marginal wind additions. For future portfolios with larger amounts of solar and storage, like the 1,200-2,500 MW of solar or 500-1,500 MW of battery capacity evaluated by PNM, the true marginal ELCC of wind additions likely would have been much higher. As noted above, the true ELCCs for wind, solar, and storage could reduce PNM's need for capacity by hundreds of MWs.

The following PNM chart shows that, in the year 2025 for the technology neutral scenario, all incremental loss of load risk occurs in summer evening hours when wind output is relatively high. Specifically, July at 7-9 PM accounts for 68% of loss of load risk, a time period when PNM's existing wind fleet averages a 24-27% capacity factor, as shown above. August at 7-9 PM accounts for an additional 15% of loss of load risk, with wind averaging a 21-22% capacity factor, and June at 7-9 PM accounts for 9%, when wind averages 28-29% capacity factor. NREL has documented that a resource's average capacity factor during the hours with the highest loss of load risk is the best proxy for its capacity value, so wind's capacity factor during high loss of load risk hours is likely a reasonable approximation of the

true capacity value of wind additions.[16] Based on existing wind's 24-27% capacity factor during peak net load hours, the true ELCC of wind additions is likely 2-3 times what PNM assumed.

Figure 85. Timing & seasonality of reliability events by 2025

Share of Expected Unserved Energy by Month & Time of Day, Technology Neutral Scenario, 2025

Month	Hour of Day (MST) 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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Greatest risk of loss of load occurs after sundown				-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.4%	3.3%	5.8%	0.7%	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3%	1.5%	1.4%	17%	37%	14%	3.1%	0.3%	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3%	0.2%	5.5%	9.2%	0.6%	0.0%	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Approximate sunset (hours with typical solar capacity factors <5%)				-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-	-

Figure 4: Modeled hourly and monthly loss of load risk, from PNM's IRP

Even this increase in wind's capacity value is likely conservative, as the capacity factors shown above for PNM's existing wind plants in the years 2013-2019, a wind fleet heavily dominated by older wind turbines with lower capacity factor and capacity value. As PNM itself notes, "newer turbines with larger rotors and higher hub heights have allowed new turbines to achieve higher capacity factors than older turbines operating in the same regime."[17] Indeed, the wind fleet averaged capacity factors of 22.4% to 28.2% for the period 2013-2018, roughly half the capacity factors that can be achieved by modern wind turbines installed in high quality wind resource areas like those available in New Mexico. For example, PNM notes that the capacity factor of the New Mexico Wind Energy Center increased from 27.7% to 34.8% in 2019 after it was repowered with more modern technology,[18] and that it assumes new wind resources offer a 43% capacity factor.[19]

New wind turbines installed going forward will perform even better as technology improves and turbines continue to increase in size. Another way to look at the above data is that the 24-27% wind capacity factor during 2025 peak net load hours corresponds to average wind output for the older vintage turbines that were operating 2013-2019. As a result, the capacity factor of new wind turbines during peak demand periods should also approximate their average output, which indicates a capacity value in the 40-50% range.

Increases in capacity factor tend to cause even larger increases in wind's capacity value, as much of the additional energy output occurs during time periods of lower wind speeds that also tend to be higher net load demand hours. Multiple studies have documented that taller wind turbines with longer turbine blades provide higher capacity value by increasing output during periods when older vintages of turbines had lower output.[20] Larger turbines are able to access higher quality, more consistent winds

[16] https://www.nrel.gov/docs/fy12osti/54704.pdf.
[17] IRP at 37.
[18] IRP at 105.
[19] IRP at 113.
[20] *See, e.g.,* Ryan H. Wiser, et al., *The hidden value of large-rotor, tall-tower wind turbines in the United States,* Wind Engineering, July 7, 2020, *available at* https://emp.lbl.gov/publications/hidden-value-large-rotor-tall-tower [hereinafter "The Hidden Value of Large-rotor, Tall-tower Wind Turbines"]; Lion Hirth and Simon Muller, *System-*

higher above the earth's surface. The increasing length of turbine blades have caused the wind energy captured by turbines to increase much more quickly than the turbines' rated capacity. This drives more consistent output by disproportionately increasing output during periods of lower wind speeds.[21] For example, MISO has found that the capacity value of wind has increased from 12.9% to 16.3% over the last decade, as technological advances have outpaced the decline in wind capacity value at higher wind penetrations.[22] Because of their different design, new wind turbines also have different output profiles from the existing fleet, reducing the correlation in their output and increasing capacity value. As new wind plants are built in new locations, this also increases the geographic diversity and the capacity value of the overall wind fleet because the output of these new wind installations is inherently less than perfectly correlated with that of existing plants. Thus, there are not only diversity benefits between wind and solar plants, but also among wind plants.

The diversity benefits among wind plants are even larger as the geographic distance between them increases, with different weather and climate patterns ensuring localized shortfalls of wind or solar generation are canceled out by higher production elsewhere.[23] As discussed later, it becomes increasingly important to assess resource adequacy on a regional or even West-wide basis at higher renewable penetrations. Planning to operate as an island becomes prohibitively expensive if these geographic diversity benefits are not realized through imports and exports. Geographic diversity also helps to counter the impact of extreme weather events that can cause extreme demand and generator outages.[24]

Given that PNM will have only 607 MW of wind relative to 1,026 MW of solar once near-term solar additions are completed, it makes sense that its power system would benefit from adding more wind to its generation portfolio. A large body of studies that have modeled optimal decarbonization strategies for the power system have converged on the finding that the optimal mix of wind and solar is around 2/3 wind and 1/3 solar.[25] This appears to be true across all power systems and driven by the fundamental differences in the output profiles of wind and solar. Solar output is entirely concentrated into daylight hours, and particularly the hours around noon, while wind output is more evenly spread across the day and seasons and tends to occur at opposite times as solar output. Had PNM accounted for the synergies between wind, solar, and storage additions, EnCompass almost certainly would have found significant wind additions to be part of an economically optimal portfolio for meeting reliability needs. Wind additions would have been particularly beneficial in the near term, given the large ongoing solar additions and the near-term availability of federal tax credits.

---

friendly wind power – How advanced wind turbine design can increase the economic value of electricity generated through wind power, 56 Energy Economics 51 (Mar. 3, 2016), *available at* https://neon.energy/Hirth-Mueller-2016-System-Friendly-Wind-Power.pdf.

[21] Ryan Wiser, et al., LBNL, *Wind Energy Technology Data Update: 2020 Edition* at 37 (Aug. 2020), *available at* https://emp.lbl.gov/sites/default/files/2020_wind_energy_technology_data_update.pdf.

[22] MISO, "Planning Year 2020-2021 Wind & Solar Capacity Credit," at 10, (December 2019), *available at* https://cdn.misoenergy.org/2020%20Draft%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf.

[23] For example, see https://www.researchgate.net/publication/305615879_Is_it_always_windy_somewhere_Occurrence_of_low-wind-power_events_over_large_areas.

[24] https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

[25] See, for example, https://www.nature.com/articles/nclimate2921 and https://netzeroamerica.princeton.edu/?explorer=pathway&state=national&table=ref&limit=200.

The IRP was based on capacity values for each resource on a stand-alone basis, but it is critical for PNM's modeling and resource selection strategy to account for the capacity value diversity benefits among wind, solar, and storage. These synergies can be accurately accounted for by iteratively analyzing the capacity value of portfolios of resources to identify the optimal mix of resources. PNM previously analyzed a preferred portfolio to replace 2 units of its San Juan Generating Station (SJGS) which were scheduled to be retired. What PNM did in the SJGS replacement resources analysis, but failed to do in its IRP modeling, was to iteratively use SERVM and EnCompass to evaluate the ELCC and economics, respectively, of potential portfolios of resource additions.[26] Instead, in the IRP modeling SERVM was only used to evaluate the addition of one resource type at a time,[27] capturing the declining ELCC with higher penetrations of each resource but not accounting for the complementarity of wind, solar, and storage in portfolios.

B. PNM overstates load growth, and thus the need for combustion turbines

As shown below, PNM projects around 20% peak load growth through the year 2040 in its base case, and around 35% in its high economic growth case.[28] PNM accounted for the potential impact of electrification in separate sensitivities, so the growth shown here is not driven by that but by projections for population and economic growth. However, as shown below PNM's own data show that peak load and energy needs have both declined significantly over the last decade, despite significant population and economic growth.[29]

[26] See the nearly 100 iterative SERVM runs in PNM Exhibit NW-2 from the testimony of Nick Wintermantel in docket PNM-19-00195-UT, at https://www.pnmforwardtogether.com/assets/uploads/replacement-plan-filing-july2019/43_Nick_Wintermantel.pdf.
[27] IRP Appendix M, at 30.
[28] IRP, at 88.
[29] IRP Appendix, C-9.

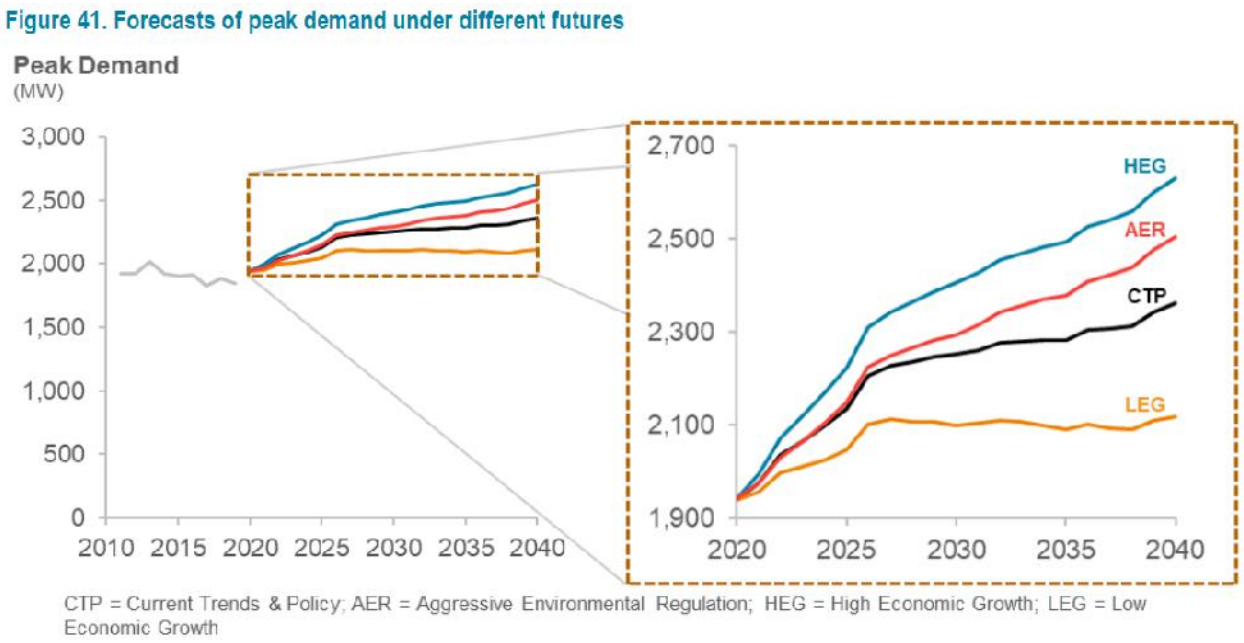


Figure 5: Historical and projected peak demand, from PNM's IRP

PNM also projects energy needs will increase significantly in almost all scenarios, despite the persistent downward trend over the last decade, as shown below.[30]

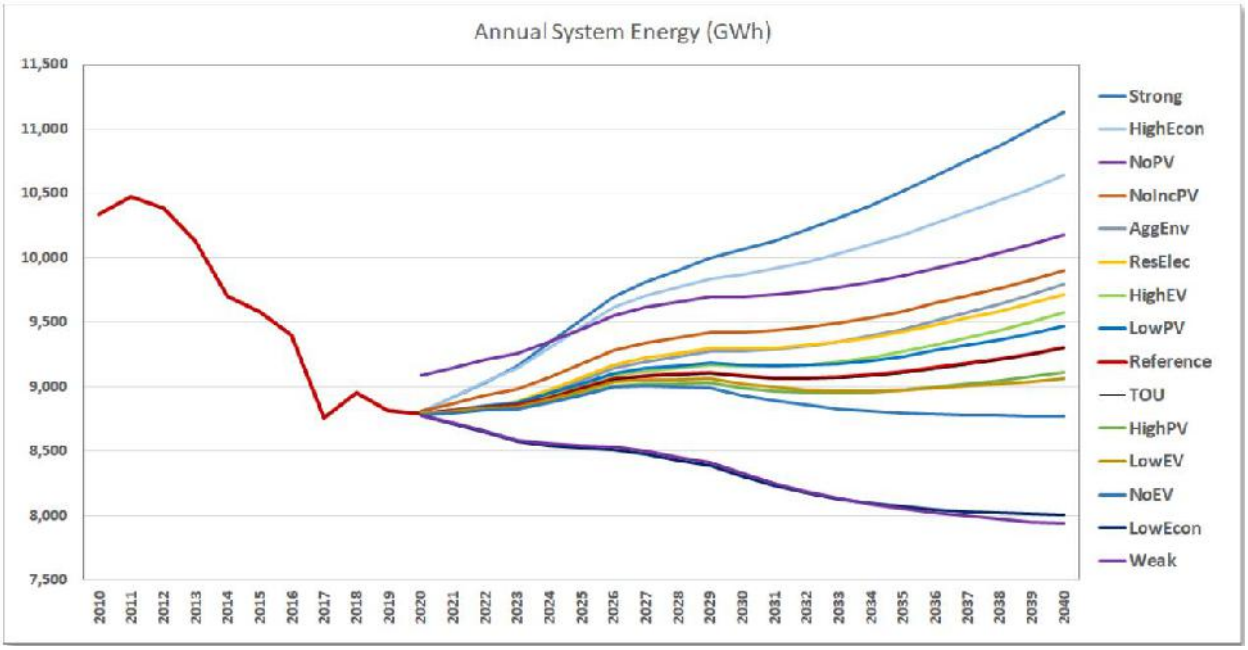


Figure 6: Historical and projected energy demand, from PNM's IRP

PNM also reveals that it has consistently overestimated load growth in its recent projections, with the following chart from the IRP showing that projections of future demand (dashed lines) have been consistently higher than actual demand (gray line), particularly for the peak demand projections shown

[30] Appendix D, page marked 115.

on the right side of the chart. Each of PNM's last five peak demand forecasts are shown with dotted lines, while the actual demand has come in significantly below those forecasts. PNM attempts to downplay this overestimation by accompanying the chart with the statement that "the difference between the 2015 forecast of 2020 peak demand and actual 2020 peak demand is only 9%."[31] To be clear, overestimating load growth by 9% over this 5-year period resulted in a capacity surplus of around 180 MW. Assuming the same rate of error persisted over the 20-year period covered by this IRP, the overestimation would be around 720 MW.

The right side of the PNM chart below also shows that PNM's 2020 actual peak demand was anomalously high due to the unprecedented heat wave, so its 2015 projections were actually high by more than 9%. A more accurate measure is that the 2015 forecast expected peak loads in the range of 2,000-2,100 MW in 2017-2019, while actually peak loads were in the 1,800-1,900 MW range in each of those years, an error of 10-15% in each year. For example, PNM's 2015 forecast predicted a peak demand of nearly 2,100 MW in 2019, yet actual peak load was around 1,850 MW, an overestimation of nearly 14%. If the rate of error over the period 2015-2019 persists over the next 20 years, PNM will have overstated its 2040 capacity needs by more than 1,000 MW.

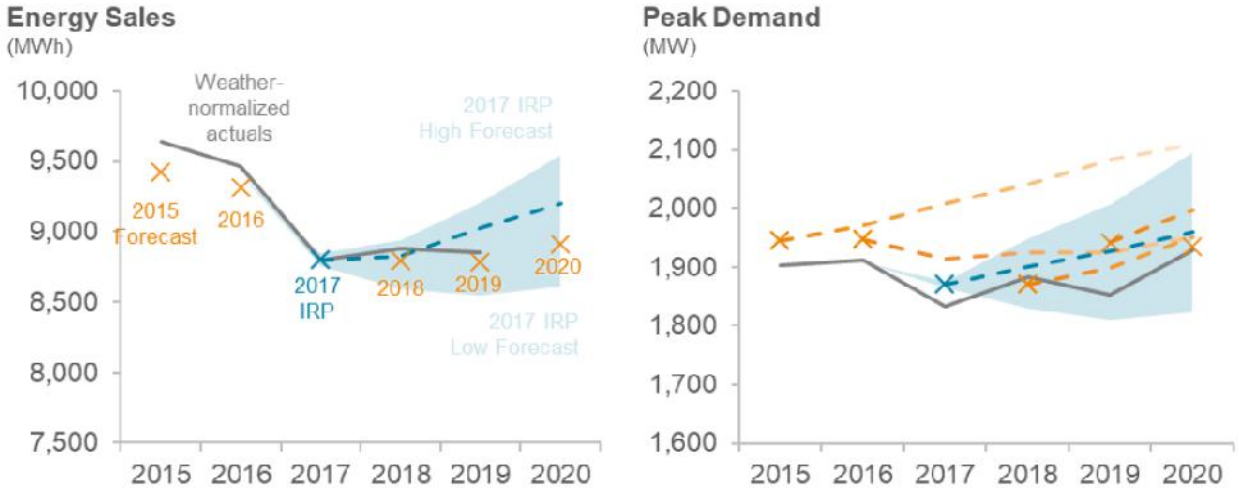


Figure 7: Historical and historically projected energy sales and peak demand, from PNM's IRP[32]

In addition to missing consumer-driven energy efficiency and other factors that have caused energy consumption to decouple from economic growth over the last decade, PNM appears to have made other errors in its load projections. For example, PNM explains that it modeled behind-the-meter PV output separately from cooling loads,[33] even though there is a significant correlation between those two factors because sun shining on buildings drives both cooling load and behind-the-meter solar output. However, that correlation was lost when PNM modeled and sorted cooling load hours separately from solar output hours. As a result, PNM does not fully account for the benefit of behind-the-meter solar PV producing the most when the sun is also driving high air conditioning demand.

[31] IRP at 89.
[32] *Id.*
[33] Appendix C9-C14.

PNM's modeling of peak load reduction from a sensitivity with Time-Of-Use (TOU) rates also misses the potential benefits of such rates. First, PNM's modeling is unclear. At one point PNM claims it assumed 80% of customers were put on a simple fixed TOU rate, in which prices are set in advance for each hour, and 20% on a dynamic rate, in which prices vary based on real-time supply and demand, and "[T]he simple [TOU] rate reduces customer peak usage by 7%, while the dynamic rate reduces customer peak usage by 21%."[34] Yet PNM later shows only a 1.1% reduction in total peak load with TOU rates in 2040,[35] even though the claimed reductions in residential demand should translate into a much larger reduction in total peak load.

More importantly, PNM modeled both the fixed and dynamic TOU rates as only reducing demand between 2-7 PM, and actually driving an *increase* in demand in the 8-10 PM period,[36] presumably by delaying electricity usage. However, this offers no benefit because, for a power system with a relatively high penetration of solar like PNM, peak net load occurs in the 8-10 PM period. In reality, TOU rates designed for a power system with a high penetration of solar have significant ability to drive beneficial pre-cooling, shifting cooling loads from late afternoon and evening hours to morning and midday, and the potential for shifting controllable loads increases with electrified transportation and heating loads. PNM should evaluate scenarios that use TOU rates to reduce demand during the time of peak net load.

C. PNM does not account for the reliability risks of fossil resources

Over the next few years, PNM proposes becoming heavily dependent on natural gas for capacity and energy. Appendix J-3 shows that in the "technology neutral" current trends and policy case, annual gas generation increases from 691 GWh in 2021 to 2,916 GWh in 2026, a more than four-fold increase in just five years. That poses both economic and reliability risks for PNM ratepayers.

PNM's reliability analysis does not account for the risk of correlated outages or derates of gas generators, yet those caused rolling outages in New Mexico in February 2011, in ERCOT in February 2021, and were a contributing factor to the rolling outages in CAISO in August 2020. Following these events, grid operators and NERC are increasingly focused on the risks associated with fuel supplies. NERC has noted how correlated outages are a major risk, particularly for gas generators.[37] NERC has specifically identified the region that includes New Mexico as being at risk of electric reliability problems if gas supply interruptions occurred, in large part because gas accounts for more than half of the Southwest Reserve Sharing Group's generating capacity.[38] NERC's Winter Reliability Assessment[39] and other NERC reports have continued to highlight this risk.

[34] Appendix C-16.
[35] Appendix D, marked page 120.
[36] Appendix C-16.
[37] NERC, "Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System," (October 2019), *available at* https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline-Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Draft.pdf.
[38] NERC, "Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System," at 3, 20, (November 2017), *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf.
[39] NERC, "Winter Reliability Assessment," (November 2019), at 6, *available at* *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf.*

PNM's modeling is based on the assumption that conventional generator outages are random, uncorrelated events.[40] For example, if data indicates that each unit of a certain type of resource has a forced outage 10% of the time, then PNM's method predicts that the odds of two units having an outage at the same time are only 1% (10% times 10%). Recent operating experience in the Southwest and elsewhere demonstrates that that prediction is invalid, as extreme weather and other events can cause many conventional generators to fail simultaneously through correlated outages due to equipment failures, capacity derates due to extreme heat, fuel supply interruptions, lightning strikes, wind storms, extreme cold, cooling water interruptions, and other problems. As a recent paper co-authored by experts from NERC and Carnegie Mellon University explained:

Our findings highlight an important limitation of current resource adequacy modeling (RAM) practice: distilling the availability history of a generating unit to a single value (e.g. EFORd, the equivalent forced outage rate during times of high demand) discards important information about when units in a power system fail in relation to one another. Only by incorporating the full availability history of each unit into RAM can we account for correlations among generator failures when determining the capacity needs of a power system. We strongly recommend that system planners incorporate correlated failure analysis into their RAM practice.[41]

NERC data used in the Carnegie Mellon analysis demonstrates that conventional generators experience correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events. Charts included in the analysis show that actual winter generation outages are much more common than would be expected under the assumption that generator outages are uncorrelated independent events.[42]

Failing to account for correlated outages of conventional generators overstates their capacity contributions relative to renewable and storage resources, as the correlated output patterns of wind, solar, and storage resources are accounted for in the ELCC methods used to calculate their capacity value. The capacity value of gas generators also declines at higher penetrations for the same reason that wind, solar, and storage resources' capacity values decline at higher penetrations: correlated output patterns. However, PNM's analysis does not account for that. This can cause PNM to miss opportunities to increase resilience by diversifying the generation mix by adding renewable generation that is not affected by fuel delivery and other constraints. The benefits of adding renewables that are not subject to fuel delivery constraints have been demonstrated in the resilience analyses conducted by PJM and the New England grid operator.[43]

Accurately assessing the capacity value contributions of resources is also critical for ensuring that a planned resource portfolio is adequate to meet reliability needs. Overestimating the capacity value of

[40] IRP at 54.
[41] Sinnott Murphy, Jay Apt, John Moura, and Fallaw Sowell, "Resource Adequacy Risks to the Bulk Power System in North America, at 29, (n.d.), *available at* https://www.andrew.cmu.edu/user/fs0v/papers/CEIC_17_02R1%20Resource%20adequacy%20risks%20to%20the%20bulk%20power%20system%20in%20North%20America.pdf.
[42] *Ibid.* at S-22.
[43] ISO-NE, "Operational Fuel-Security Analysis," at 33 (January 17, 2018); For a discussion of the PJM study results and a link to the study and its appendix, see Michael Goggin, "PJM Study Quantifies Wind's Value for Building a Reliable, Resilient Power System," (April 4, 2017).

new gas generation not only results in an economically suboptimal resource mix, but it can also cause electricity supply to fall short of demand. Accounting for the correlated outages experienced by some types of resources by reducing those resources' capacity value would address both problems.

Separately, PNM appears not to have accounted for a potential reduction in contingency reserve needs following the retirement of the San Juan Generating Station ("SJGS"). As PNM notes at page 56 of the IRP, "Beyond 2022, once SJGS is no longer part of our portfolio, the Afton Combined Cycle (235 MW) will become PNM's single largest contingency when operating." The retirement of the SJGS Unit 4 could reduce PNM's need for new capacity by reducing the amount of spinning and non-spinning reserves PNM must hold as a contingency for the loss of that unit.

D. PNM understates the availability of market purchases

PNM explains its assumed level of imports as follows:

For this plan, we assume that the level of market assistance that we can count upon during the most constrained "net peak" hours is limited to 50 MW, consistent with recent operating experience. In previous plans, we have assumed that the market would be able to supply 200-300 MW of energy when needed. However, recent experience during the summer of 2020, coupled with the anticipation that reserve margins throughout the region are shrinking, have prompted us to reconsider this assumption. Our latest assumption represents the level of imports that our planners and operators have a reasonably high degree of confidence will be available when needed.[44]

First, it should be noted that PNM's IRP indicates it still imported around 100 MW during its peak demand periods in 2020,[45] indicating there is no basis for limiting imports to 50 MW. PNM also claims that during the tail end of the 2020 heat wave event, its traders were unable to buy power despite offering high prices.[46] However, the fact that PNM was able to meet its demand indicates that offered prices could have gone even higher if PNM truly needed more imports to meet demand, and purchases presumably could have been secured at those even higher prices.

PNM also presents data showing that market purchases have declined in recent years. However, rather than indicating a declining supply of imports, declining market purchases can simply indicate PNM has experienced reduced demand for imports, potentially due to PNM's recent high load growth assumptions, as discussed above. Analysis in the SJGS replacement resources case no. 19-00195-UT showed 350-450 MW of market purchases were available when both PNM demand was high and market prices were high.[47] Imports during time periods when electricity demand is high and prices are high is

[44] IRP at 152.
[45] IRP at 49.
[46] *Id.*
[47] As Mr. Goggin testified in his direct testimony in docket PNM-19-00195-UT, "Market data provided by PNM in response to CCAE's interrogatory 8-20A indicates that PNM typically buys 350 MW or more from market purchases during time periods when electricity demand is high and market prices are high. Specifically, in all hours in which market prices exceeded $100/MWh and PNM electricity demand exceeded 1850 MW, PNM made at least 352 MW of market purchases and an average of 399 MW of purchases, for the January 2017-June 2018 period for which PNM provided market price data.

In its response to CCAE 8-20A, PNM provided some analysis of market purchases during periods with *either* high demand or high prices. However, periods with *both* high demand and high market prices are the best indicator of the availability of market purchases when both PNM and its neighbors are experiencing high demand

much more relevant for assessing the availability of market purchases for meeting resource adequacy needs than the total volume of purchases. Interestingly, Appendix J3 to the IRP shows that in the technology neutral case with current trends and policy, PNM reduces market purchases by 1,500 GWh per year between now and 2027, about 15% of its total supply. PNM could continue making those market purchases to meet its needs, displacing most if not all of the need for the proposed combustion turbines.

More importantly, the 2020 West-wide heat wave was unprecedented in both its severity and geographic breadth.[48] While the severity and breadth of heat waves is increasing due to the impacts of climate change, the probability of a West-wide event within PNM's IRP planning horizon is low. West-wide resource and geographic diversity along with market purchases and imports will likely become increasingly important for addressing localized extreme weather events, as noted earlier.

For California, the 2020 heat wave was quantified as a 1-in-30 year event,[49] but the breadth of the heat across much of the West makes it even rarer. For example, the June 2021 Pacific Northwest heat wave was quantified as a 1-in-1000 year event in today's climate,[50] yet the heat wave most severely affected California and the Pacific Northwest at different times, allowing each region to meet load using imports from the other region. Given that heat waves with the geographic breadth of the 2020 event are an extreme anomaly that are unlikely to recur more frequently than 1 in every 10 years, it should not form the basis of PNM's resource adequacy planning based on a 1 day-in-10 year loss of load probability target. There is some variability in when weather systems affect different parts of a region,[51] and events are typically only at their most extreme in a relatively narrow area, particularly for a large region like the Western U.S. PNM is incorrect to claim that it is typical for all regional power systems to experience peak demand at the same time, or that such a situation is likely to occur within its resource planning horizon.[52]

---

and are short on supply. PNM demand alone does not indicate periods when PNM's neighbors are short on supply, while market prices alone do not indicate that PNM is experiencing high demand. Including both factors ensures that the analysis is appropriately conservative by focusing on time periods when both PNM most needs market purchases and PNM's neighbors are least able to provide them.

There is reason to believe that the availability of market purchases during peak demand periods could be even higher than 350 MW. During the hours when PNM demand is above 1850 MW and prices are above $100/MWh, PNM market purchases have been as high as 442 MW. Prices during hours when PNM demand is above 1850 MW only reached as high as $141/MWh, which is well below the prices that are typically seen during true electricity scarcity events. Neighboring balancing authorities likely have many oil-fired units and some gas-fired units that would typically only be started if prices went higher than $141/MWh. This strongly indicates that if PNM had needed more purchases during hours of high demand, they would have been available at a reasonable price."

[48] There are several geographically diverse regions within the West, including California, the Pacific Northwest, the desert Southwest, the Rocky Mountain region, the High Desert, etc.

[49] http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[50] https://www.climate.gov/news-features/event-tracker/preliminary-analysis-concludes-pacific-northwest-heat-wave-was-1000-year.

[51] https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

[52] See PNM's statement at page 30 in the IRP: "The types of weather events that lead to the highest demands are typically regional in nature, so that when our system is experiencing peak demand conditions, many others throughout the region are at or near peak demand as well. What this means is that during our peak period, the amount of energy available on the wholesale market is relatively limited, as most utilities are focused on meeting their own needs with their own resources."

This can be confirmed with analysis of EIA hourly load and generation data for Balancing Authorities across a region,[53] which shows the reduction in peak capacity needs from aggregating diverse loads and renewable resources across larger regions. This benefit occurs because peak loads and renewable output profiles are not perfectly correlated across large areas. The data shows that, even in 2020's worst case scenario of a west-wide heat wave, there are still significant geographic diversity benefits across the West.

As shown in the duration curves below, the Northwest Power Pool could have realized a 5 GW reduction in peak load and 7 GW reduction in peak net load (from 2 GW of renewable diversity benefit) in 2020 if it aggregated diverse loads and renewable resources by evaluating resource adequacy on a regional basis. In other words, given the 60 GW peak NWPP load, participating utilities could have received a nearly 13% boost to their reserve margins if they accounted for the benefits of aggregating loads and renewable resources across the footprint. Similar analysis could be done for the Southwest region, and even for the entire Western U.S., which would likely show similar benefits.

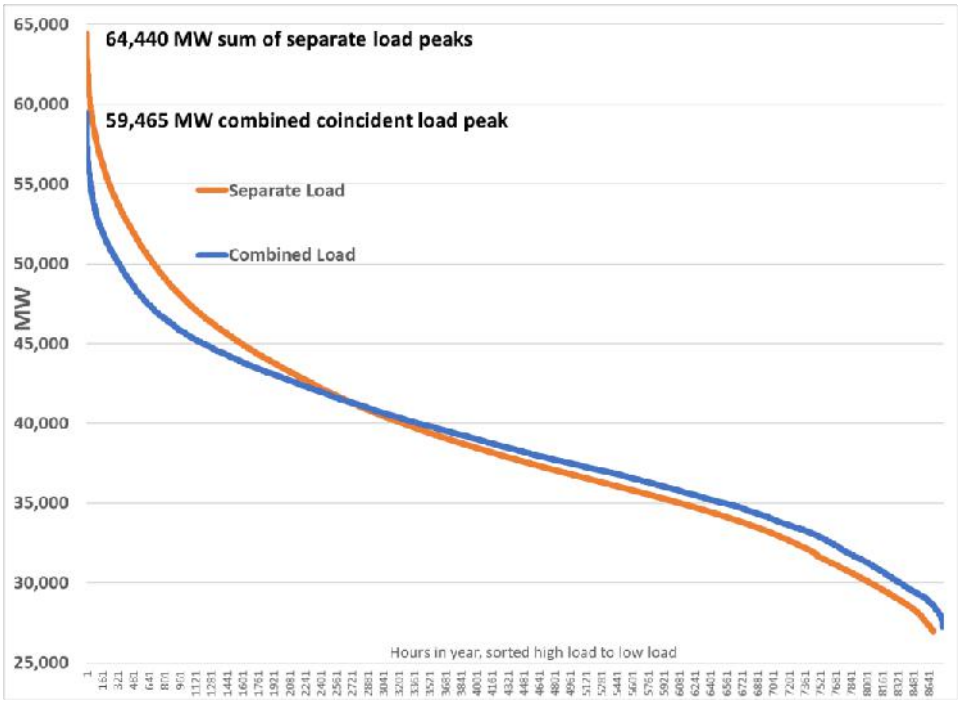


Figure 8: Peak load reduction by aggregating across US portion of NWPP

[53] https://www.eia.gov/electricity/gridmonitor/knownissues/xls/Region_NW.xlsx.

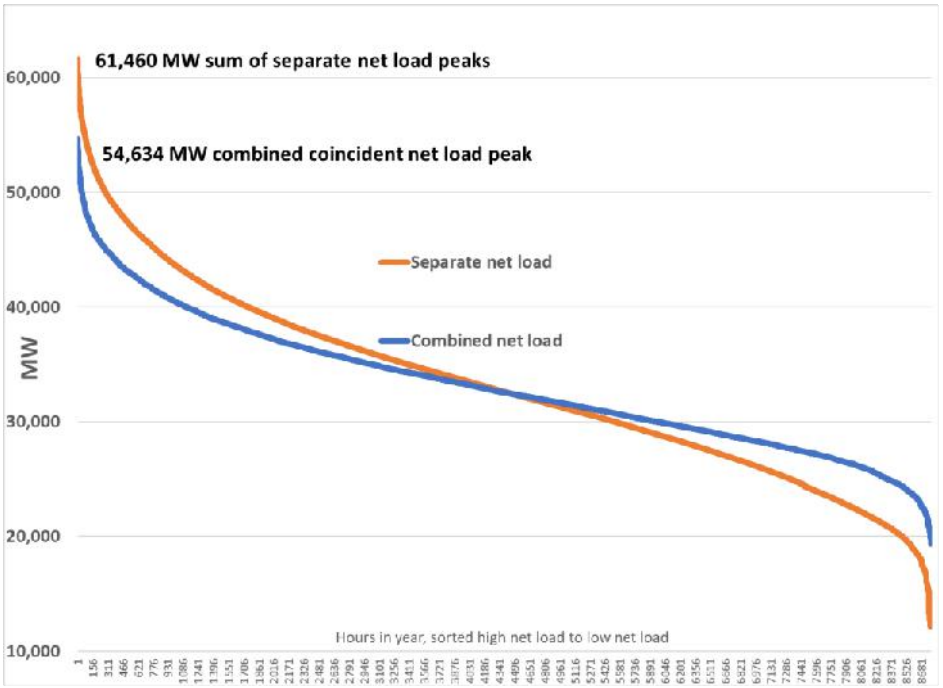


Figure 9: Peak net load reduction by aggregating across US portion of NWPP

PNM's interpretation of the lessons of the California 2020 outage is also questionable when it states that "[A]s demonstrated by California's 2020 blackouts, failure to adjust planning practices to accommodate increasing quantities of variable and energy-limited resources may have serious consequences."[54] California's report on the outages indicates that some of the largest causal factors were 1,000 MW of gas plant failures and derates and a transmission outage reducing imports from the Pacific Northwest by 650 MW.[55] Moreover, California's ongoing addition of several GW of battery storage will shift afternoon solar production to meet evening peak net load, addressing concerns about solar's variability.

The fact that the 2020 event was caused by an anomalously large weather event coinciding with generation and transmission outages, and that ongoing storage additions would prevent such an event in the future, provides further evidence that the event should not form the basis for resource adequacy planning. In the SJGS replacement resources case, PNM assumed imports of 200-300 MW were available,[56] and PNM has provided no solid evidence that fundamental trends have changed since then.

PNM claims that reserve margins are low throughout the Southwest, yet NERC data show the opposite. NERC's data show that for at least the next 10 years, reserve margins for the SRSG that PNM belongs to are at least 50% above the reference margin level that is based on the 1-day-in-10 years standard if planned resource additions are accounted for. As NERC notes, "The Anticipated Reserve Margin does not fall below the Reference Margin level for any year for any of the assessment areas within WECC for the peak hours analyzed in the assessment period."[57] NERC continues, "[T]he results from this

[54] IRP at 44.
[55] http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf, 47-48.
[56] PNM response to CCAE interrogatory 8-20C in docket PNM-19-00195-UT
[57] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf, at 154.

assessment indicate that all [WECC] assessment areas are resource adequate in the short, near, and long term with their current resource portfolio plans." Moreover, even in a probabilistic stress test with unusually high levels of demand, forced outages, and low renewable output for the region, NERC observed "insignificant levels of [Loss of Load Hours] and [Expected Unserved Energy]."[58] In other words, under both normal and worst case assumptions, the SRSG region is not at risk of supply shortfalls and has a large amount of surplus capacity that PNM can use to meet its needs through market purchases.

More fundamentally, uncertainty about the future availability of imports should have been accounted for probabilistically in SERVM's Monte Carlo analysis, and not with a deterministic worst case assumption as PNM did.[59] The following table from Astrape's report shows that the required reserve margin to meet a 0.2 LOLE is heavily dependent on the assumed availability of market imports,[60] with the needed reserve margin dropping from 18% to 10% if market imports are increased from 50 MW to 200-300 MW, as shown in the lower right of the table. The right column of the table shows the accredited capacity reserve margin that must be held to meet the 0.2 LOLE standard, which changes dramatically depending on assumptions about the availability of market imports. As a result of using a deterministic assumption in a probabilistic analysis, PNM is incorrectly stating with certainty that a reserve margin of 18% is required, based on the uncertain and unlikely assumption that only 50 MW of imports will be available during peak net load hours.

Market Support	RM ICAP	RM UCAP
Island	**27%**	**23%**
50 MW Cap 24Hrs	**25%**	**20%**
0-50 MW Cap Net Peak Hours	**24%**	**20%**
50 MW Cap Net Peak Hours	**22%**	**18%**
With 200-300 Market	**14%**	**10%**

Figure 10: Needed reserve margin depending on import assumptions, from Astrape's report in IRP

Moreover, as California and other states to the west of New Mexico continue to expand their penetration of solar and storage resources, increasing amounts of energy will likely become available for import at a reasonable price during summer late afternoon and evening peak demand periods within PNM's load areas. New Mexico is particularly well-positioned to benefit from solar growth because it is on the eastern end of the Western Interconnect, so PNM's evening peak demand can be met with solar imports from states to the west where the sun is still higher in the sky.[61]

Increased transmission capacity and more coordinated regional planning and operations will further help PNM meet resource adequacy needs with market purchases

PNM notes how its planned retirements free up transmission capacity for future resource additions, stating that "the future abandonments of FCPP and leased shares of PVNGS will create additional

[58] Ibid., 162.
[59] IRP at 152.
[60] Appendix M at 36-37.
[61] During late July, sunset occurs 60 minutes later in Southern California and 90 minutes later in parts of the Northwest.

headroom on the transmission system. Our planning efforts assume that these abandonments enable up to 314 MW of existing transmission to be repurposed for new resource development by 2025."[62] However, these retirements also free transmission capacity for increased imports, given that the retiring resources are located along PNM's primary transmission connection to power systems to its west and north.

The ongoing addition of large-scale battery storage along the transmission lines between northwestern New Mexico and the Albuquerque load center further makes it possible to accommodate both new renewable resources and expanded imports on those lines. This is because the battery can charge during periods of high renewable output or high imports to prevent the overloading of the lines, and then discharge at a later point in time once transmission capacity has become available.

Other retirements in the region, such as Navajo Generating Station, as well as reductions in output from Glen Canyon and Hoover Dam due to drought, can further increase the availability of transmission capacity for market purchases.

PNM also correctly notes a number of ongoing and proposed transmission expansion projects.[63] Some of these directly increase import capacity, while for others PNM could potentially make modifications to its system to connect to the lines to obtain import capacity. For example, PNM could investigate the possibility of building AC transmission to connect to large proposed interstate transmission projects like SunZia or Southline and contractually arranging for the ability to import power on those lines.

More coordinated planning and operations across the West will also reduce PNM's need for capacity by capturing geographic diversity in electricity demand and renewable output. While PNM is correct that existing Western Energy Imbalance Market ("EIM") rules prohibit leaning on the capacity of other participants, the EIM does reduce PNM's need for capacity. By reducing the amount of flexible capacity that must be set aside for providing upward operating reserves, PNM's access to the EIM frees up capacity from providing operating reserves that can be instead used to meet peak demand. The EIM test that prevents entities from leaning on other participants includes a "diversity benefit factor" that reduces the ramping self-sufficiency requirement for participants in proportion to the load and resource diversity benefits provided by the EIM.[64]

The diversity benefit of aggregating supply and demand across the West currently reduces all EIM participants' flexibility needs by around one-half,[65] and that figure has continued to grow as the EIM expands. A central value proposition of the EIM is "flexible ramping procurement diversity savings." As the EIM operator explains, "[B]ecause variability across different BAAs ["Balancing Authority Area"] may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA's requirements."[66] This likely accounts for a significant share of the

[62] IRP at 126.
[63] IRP at 128-134.
[64] Megan Poage and Brittany Dean, "EIM Offer Rules Workshop," at 16-17, (July 19, 2018), *available at* http://www.caiso.com/Documents/ISOPresentation-Jul19_208-EIMOfferRulesTechnicalWorkshop-ResourceSufficiencyTest.pdf.
[65] California ISO, *Western EIM Benefits Report: First Quarter 2021* (Apr. 29, 2021), at 22 https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q1-2021.pdf.
[66] CAISO, "Western EIM Benefits Report," at 15, (October 29, 2019), *available at* https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ3-2019.pdf.

benefits PNM expects to receive from the EIM; as PNM noted, "[W]e expect the benefits of participation in the EIM to be $17-21 million per year, while the costs of joining the market would require one-time capital and O&M expenditures of $28 million and ongoing costs of $3-4 million per year."[67]

It is well-established that the diversity benefits of EIM participation allow a reduction in participants' operating reserve needs. For example, in a rate case proceeding at FERC, PacifiCorp calculated that EIM participation reduced its frequency regulation operating reserve needs by 38%.[68] By reducing the operating reserve needs of participants, the EIM frees up capacity that would have been reserved to provide operating reserves so it can meet other needs, like providing peak capacity. This is much like how PNM's participation in the SRSG spinning and non-spinning reserve sharing pool frees up capacity for meeting peak demand needs that PNM otherwise would have been required to hold as operating reserves.

In addition, the centralized market offered by an EIM helps drive greater liquidity in Western power markets relative to past experience in which all transactions had to be scheduled bilaterally. This should increase the availability of market purchases to PNM. Ongoing evolution of Western power markets towards more coordination planning and operations should further increase the availability of market purchases for meeting resource adequacy needs. PNM correctly notes ongoing discussion about adding day-ahead functionality to the EIM.[69] In addition, PNM correctly notes that

Utilities in some parts of the Western Interconnection have also begun to explore the possibility of a regional resource adequacy program. The Northwest Power Pool, which includes utilities across nine western states and two provinces, is currently in the early stages of establishing a regional program for resource adequacy. This effort has been motivated by a growing concern that a large number of plant retirements, coupled with excessive reliance on the market to meet individual utilities' resource adequacy needs, could lead to a regionwide capacity deficit. Such a program has not yet been contemplated or proposed within the Southwest but could have implications for how resource adequacy obligations are established and shared among utilities in the region in the future.
All of these examples point towards a broader recognition among Western utilities that as the interconnection as a whole transitions towards greater reliance on non-firm resources, exploring organized market structures has the potential to lower costs and produce benefits for participating utilities.

Much like PNM's analysis of the capacity value of wind, solar, and storage was flawed because it examined additions of each resource type in isolation, capacity value also should have been evaluated on a regional basis instead of only looking at PNM in isolation. This would better reflect the operational reality of Southwestern power systems today, and particularly the inevitable evolution to a more integrated Western power system over the coming decades.

Broader regional coordination will reduce PNM's need for capacity

Extensive regional coordination in system planning and operations is essential if the West is to cost-effectively reach the high penetrations of wind and solar resources called for under laws in New Mexico and other states. As a result, PNM's planning should account for the high likelihood of this evolution

[67] IRP at 21.
[68] See PacifiCorp filing in FERC Docket ER17-219-000, at 45-48 *available at* https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14386396.
[69] IRP at 34.

over the planning horizon. PNM should take particular care that it does not invest in capacity resources that will not be needed and will become stranded assets with more coordinated planning and operations in the West, particularly given the large capacity surplus in the region, as documented later in this section. Given the likelihood of more coordinated planning and operations over PNM's planning horizon and the short timeline needed to build capacity resources, PNM should wait and see if that evolution reduces the need for capacity before making irreversible and costly investments in capacity resources. This is particularly important before making risky investments in resources that will operate on alternative fuels like hydrogen, which as explained in the next section have very high and uncertain costs.

Large import and export ties are essential for reliable and affordable power system operations at high renewable penetrations, as these connections provide access to diverse wind and solar resources. A large body of regional[70] and national[71] analyses conclude that a diverse mix of wind, solar, and other resources is essential for economic and reliable decarbonization of the power system. As a national study published in the journal Nature Climate Change explained,[72] "the average variability of weather decreases as size increases; if wind or solar power are not available in a small area, they are more likely to be available somewhere in a larger area," so "paradoxically, the variability of the weather can provide the answer to its perceived problems." Moreover, with existing and new high-voltage regional transmission, like the proposed Gateway and SouthWest Intertie Project projects, Southwest power systems can access significant resources to meet summer peak demand from winter-peaking Northwest power systems.

The Western Interstate Energy Board's 2019 Western Flexibility Assessment found that with West-wide planning and operational coordination, some transmission expansion, and other flexibility solutions, a clean energy penetration of 69% could be reached by 2035 with only 9% of renewable energy curtailed. In a baseline case, the clean energy penetration only reached 52% and 20% of renewable energy was curtailed; and in a scenario with limited regional coordination, the clean energy penetration only reached 49%, with 46% curtailment.[73] Such high amounts of curtailment come at significant cost to consumers, and limit the penetration of clean energy to levels well below those required by New Mexico law. As a result, it does not make sense for PNM to plan for 2040 electric sector decarbonization based on the assumption that there will be no improvement in regional coordination over the next two decades.

Another study by The Brattle Group and Boston University found that interconnecting two power systems with high renewable penetrations through transmission investments can reduce annual

[70] Christopher T.M. Clack, et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.* (Americans for a Clean Energy Grid Oct. 2020), *available at* https://cleanenergygrid.org/wp-content/uploads/2020/11/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf [hereinafter "Benefits of Electricity Transmission Expansion"].
[71] *See, e.g.,* Patrick Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 Joule 115 (Jan. 20, 2021), *available at* https://www.sciencedirect.com/science/article/abs/pii/S2542435120305572.
[72] Alexander E. MacDonald, et al., *Future Cost-Competitive Electricity Systems and Their Impact on US CO2 Emissions* at 1 (Nature Climate Change Jan. 25, 2016), *available at* https://www.vibrantcleanenergy.com/wp-content/uploads/2016/09/Future_cost-competitive_electricity_syst.pdf.
[73] https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf, at 111-112.

production costs by between 2% and 23%, and annual renewable curtailments by 45% to 90%.[74] NREL has also identified greater use of imports and exports as one of the most economical strategies for accommodating the variability observed on power systems with large amounts of wind and solar. Specifically, NREL found that in modeling case studies of California, Florida, and the Southwest Power Pool, increasing exports provided the largest or second largest benefit for facilitating renewable adoption.[75] NREL's Western Wind and Solar Integration Study also showed that while large amounts of wind and solar can significantly increase power system variability in a single grid operating area, if renewable output is aggregated across the Western U.S. then power system variability actually decreases.[76]

A variety of studies have shown that large import and export ties are particularly important for power systems with high solar penetrations, like PNM's and others in the Southwest. These power systems need large ties to both export high midday solar output, and import other resources, like wind and hydropower, in the evening and night when solar is unavailable.[77] The evolution to West-wide coordinated planning and operations of the electricity system will be essential for New Mexico and other states to achieve their decarbonization requirements.
As a result, PNM should be focused on regional solutions to meeting its needs, looking not just at its current system, but across the Southwest and across the entire Western Interconnect. Wind and existing hydropower reservoirs in other parts of the West can significantly complement PNM's resources. A more regional view of resource adequacy likely would have significantly increased the ELCCs of PNM wind, solar, and storage resources. For example, given New Mexico's position on the eastern end of the Western Interconnect, PNM solar resources can help meet the early morning load ramp in California. PNM's wind resource also provides significant value to the solar heavy power systems to its west, given the large synergies between wind and solar discussed above.

III. Economics

A. Cost assumptions for renewables and storage are too high

PNM's assumed costs for new wind, solar, and battery resources are well above actual costs in the market. PNM's assumed 2022 cost and project sizes from Appendix I, copied in the first two rows of the following table, are converted to $/Watt costs in the third row of the table.

Table 2: PNM cost assumptions for new renewable and storage resources, converted to $/W

	LM6000	Wind	Solar	Hybrid solar-battery	4hr battery	8hr battery	Flow 10hr
MW	40	400	10	10	10	10	300
$ (thousands)	$41,313	$700,576	$14,155	$15,690	$14,892	$23,733	$35,632
$/Watt	$1.03	$1.75	$1.42	$1.57	$1.49	$2.37	$0.12

[74] https://www.bu.edu/ise/files/2020/09/value-of-diversifying-uncertain-renewable-generation-through-the-transmission-system-093020-final.pdf.
[75] Paul Denholm et al., NREL, *Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies* at vii-xi, (Dec. 2016), *available at* https://www.nrel.gov/docs/fy17osti/66854.pdf.
[76] GE Energy, *Western Wind and Solar Integration Study* at 83, (NREL May 2010), *available at* https://www.nrel.gov/docs/fy10osti/47434.pdf.
[77] Benefits of Electricity Transmission Expansion at 21.

At $1.75/W, the assumed cost of new wind is 22% higher than the average cost of wind projects installed in 2019, which was $1.44/W.[78] For solar, PNM's assumption of $1.42/W is marginally higher than the median cost of $1.40/W-AC reported for utility-scale projects in 2019.[79] These are national cost figures, so costs are likely to be even lower in New Mexico given the below average cost of land and the fact that shorter wind turbine towers can be used in high quality wind regimes like those present in New Mexico.

For both wind and solar, ongoing cost reductions between 2019 and 2022 should have yielded significantly lower costs than indicated by PNM's assumptions for 2022 costs. For example, NREL's Annual Technology Baseline shows 2022 wind costs of $1.305/W in its middle cost case, and $1.256/W for 2022 solar costs in its middle cost case.[80] These figures are 34% and 13% lower, respectively, than PNM's assumed costs. Similarly, NREL shows 4-hour battery costs of $1.2/W in its moderate case, 24% less than PNM's assumption; and 8-hour battery costs of $2.168/W, 9% less than PNM's assumption.

PNM indicates that its assumption for the current cost of resources is based on data obtained through its confidential RFPs, though it provides no detail or transparency in how it used the data from RFP responses.[81] PNM then uses NREL's Annual Technology Baseline to model the future cost reduction trajectory for renewable and storage resources from that current starting point. As a result, if the current cost of resources is too high, which is demonstrated to be true above, then the projected costs will also be too high in all future years. PNM does not provide information about how RFP cost data was weighted, which makes it difficult to determine why its cost assumptions are too high. For example, if PNM used median or average costs from all bids submitted, instead of the more competitive bids that were actually selected, this would also cause an upward bias in the cost assumptions. PNM also could have included bids from RFPs conducted many years ago, which would not reflect recent cost reductions for wind, solar, and storage.

It seems that PNM included assumed transmission cost that account for at least some of the discrepancy between its assumptions and national cost figures. However, PNM's IRP provides no detail on what those transmission cost assumptions were and how they were produced. Greater transparency around transmission cost assumptions is essential to be able to evaluate PNM's modeling.

In addition, the assumed 400 MW minimum size for new wind projects is nearly twice as large as typical wind projects, and much larger than many small yet economic wind projects.[82] This large minimum size biases EnCompass against selecting wind resources, as the energy and capacity provided by a 400 MW wind project is much larger than PNM's incremental need in any one year. PNM's assumed project size misses the value provided by the modularity of wind resources, as capacity additions can be tailored to meet incremental needs, unlike the lumpy additions of most conventional generators. This, combined with the flawed reliability and cost assumptions discussed above, likely drove EnCompass not to select wind resources even though they offer significant economic and reliability benefits to PNM.

[78] https://emp.lbl.gov/wind-technologies-market-report.
[79] https://emp.lbl.gov/utility-scale-solar.
[80] https://data.openei.org/files/4129/2021-ATB-Data_Master.xlsm.
[81] IRP at 114-116.
[82] https://emp.lbl.gov/wind-technologies-market-report.

Furthermore, the assumption of such a large project size should also yield significant economies of scale, further reinforcing the conclusion that PNM's cost assumptions are out of step with the national cost data for more typically-sized projects.

In addition, PNM inexplicably assumed a 65% round-trip efficiency for 8-hour lithium ion batteries.[83] There is no compelling reason why the efficiency should be significantly lower than the 87% used for 4-hour lithium ion batteries. This assumption incorrectly biased PNM's resource selection against longer-duration lithium ion batteries.

As shown in the cost data above, PNM also inexplicably assumed that hybrid solar-battery projects cost $1.57/W, even though comparably sized stand-alone solar and 4-hour battery projects cost only $1.42/W and $1.49/W, respectively. Because of shared equipment and other cost savings, in reality solar-battery hybrid projects are about 7-8% cheaper than stand-alone solar and storage projects of the same size.[84] Moreover, the storage component of hybrid plants is eligible for the current 26% federal investment tax credit, while stand-alone storage resources are not.

Finally, PNM's assumed 8,200Btu/kWh[85] heat rate on LM6000s is low, making its fuel costs appear artificially low; in reality, the manufacturer's stated heat rate is more like 8500-8700 Btu/kWh.[86] The heat rate will also significantly decline when operating on hydrogen, given its lower energy density and need for energy-intensive NOx mitigation strategies given the large NOx emissions from hydrogen's relatively high combustion temperature.[87] As a result, PNM is understating the cost of operating combustion turbines on either natural gas or hydrogen. This is an important factor given that renewable hydrogen fuel is likely to come with an extremely high cost, as discussed in the next section.

B. PNM makes the risky assumption that alternative fuels for combustion turbines will be economic and available by 2040

By assuming unproven renewable hydrogen technologies will be available and cost-effective by 2040, PNM is not only taking on the economic risk of new combustion turbines being a stranded asset, but also a reliability risk if the renewable hydrogen technology improvements fail to materialize and the combustion turbines are not able to operate. PNM acknowledges there are large uncertainties, and likely large costs, in every step of renewable hydrogen production, transport, and storage:

Present expectations suggest that these fuels would likely be costly to produce, deliver, and store; nonetheless, we 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 our 100% [carbon emissions-free] 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

[83] Appendix I-1.
[84] Fu, R., Remo, T., and Margolis, R. (2018), *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*, November 2018, https://www.nrel.gov/docs/fy19osti/71714.pdf, p. 17.
[85] Appendix I-1.
[86] https://www.ge.com/gas-power/products/gas-turbines/lm6000.
[87] https://www.sciencedirect.com/science/article/pii/S0360544219323412.

are available will have particularly significant ramifications upon the nature of the challenges we encounter as our portfolio approaches 100% carbon emissions-free energy.[88]

PNM's willingness to embrace the costs and risks of electrolytic hydrogen technology contrasts with its skepticism of utility-scale battery storage, which is a proven commercial technology that is being widely adopted by PNM and other utilities today. PNM's cautions about battery technology, like "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," are many times more applicable to electrolytic hydrogen technologies that are at best unproven and in many cases depend on technologies that have not yet been invented for them to work at a commercial scale. Yet PNM seems willing to make a large economic and reliability bet on combustion turbines that will become stranded assets less than two decades from now unless all of those technological hurdles are overcome.

PNM assumes that in 2040 it will be able to retrofit new combustion turbines to operate on 100% hydrogen for a cost of only $154/kW,[89] without providing any documentation or confidence for that cost estimate. More concerningly, PNM assumes that renewable hydrogen will be available at an all-in costof $40/MMBtu,[90] or roughly 20 times the current price of natural gas. However, given the substantial uncertainties and unproven technologies in each of the steps of producing, transporting, storing, and using renewable hydrogen at scale that may be a significant underestimate.

While PNM notes that hydrogen is used in refining and other industrial processes today, that hydrogen is almost entirely produced by reforming natural gas. Less than 0.1% of global hydrogen production today is via electrolysis.[91] As a result, electrolyzers are an immature technology, particularly the large-scale electrolyzers that would be required for renewable electrolysis for electricity generation. Most current electrolyzer designs also rely on significant usage of precious metals for efficiency and longevity, which may also prevent cost-effective global adoption of electrolysis. While technology improvements may reduce costs, most cost reductions are driven by increasing the scale of production.[92] However, demand for electrolytic hydrogen remains low,[93] and is unlikely to significantly increase until major cost reductions occur throughout the supply chain.

Because most hydrogen is produced on demand today by reforming natural gas, large-scale hydrogen storage technology is also immature. Long-term high-capacity hydrogen storage will likely be required for PNM to ensure hydrogen is available for the time periods in which PNM intends to use it. Hydrogen's low density requires storage tanks that are very large or operate at very high pressure. In addition, storage challenges are complicated by hydrogen embrittlement of metals and permeation of polymers

[88] IRP at 39.
[89] IRP at 118.
[90] IRP at 119: "Our analysis assumes an exogenous price for the delivered cost of hydrogen to our plants. This all-in cost is intended to include costs of production (including costs of electrolyzers, renewable generation, and other infrastructure necessary), transportation, and storage. This study assumes a delivered cost of $40/MMBtu for hydrogen in 2040."
[91] https://www.iea.org/reports/the-future-of-hydrogen.
[92] https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf, at 13.
[93] https://www.iea.org/reports/the-future-of-hydrogen.

that could be used for the tanks.[94] Hydrogen compression is very energy intensive due to hydrogen's low density. In addition, due to its small molecular size, there are large hydrogen losses throughout the production, transportation, and storage steps, which poses both cost and potentially safety risks that must be addressed due to hydrogen's flammability. Hydrogen can be liquified and stored, though this adds further costs for equipment, energy inputs, and losses due to boil-off. Under any production, transport, storage, and generation pathway, and even with substantial technology improvements, the round-trip efficiency of hydrogen generation will be very low, further increasing costs. For example, electrolyzers are only 70-90% efficient, compression or liquefaction consumes 5-35% of the energy in hydrogen, and combustion turbines are at maximum only 35% efficient, so those three steps alone typically result in an efficiency well below 20%, without even factoring in significant leakage of hydrogen during all process steps.

The capacity factor for equipment used in renewable hydrogen production, transport, and storage would also be low because hydrogen would primarily be produced when there is excess renewable output, which is likely to be a relatively small percentage of the time. Said another way, the vast majority of the time, expensive hydrogen production and transport equipment will sit idle because renewable output is being used to meet load and not produce hydrogen. As noted above, PNM shows that the capacity factor for generation at the hydrogen-fueled combustion turbines will also be very low, at only 1% in the Current Trends and Policy future in the technology neutral case.[95] This further increases the cost of each of these capital-intensive process steps.

Due to chemical properties like metal embrittlement, hydrogen cannot be used in existing natural gas infrastructure and thus will need dedicated storage and transport infrastructure.[96] As a result, dedicated equipment will be required for hydrogen transport and storage, further limiting the utilization factor of this equipment, increasing its cost, and posing the risk of stranded assets if renewable hydrogen proves not to be economically viable.

PNM assumes a 97% availability factor for hydrogen-powered combustion turbines, even higher than its assumption for conventional gas turbines.[97] Given the novel equipment and processes used in hydrogen combustion turbines, and the potential for failures throughout the similarly novel hydrogen production, transport, and storage supply chain which could take PNM's entire fleet of hydrogen combustion turbines offline, PNM's assumed availability factor for hydrogen combustion turbines should be much lower.

PNM claims the combustion turbines could also be operated on renewable natural gas or synthetic hydrocarbons.[98] However, the production of carbon neutral synthetic hydrocarbons will rely on both cost-effective renewable electrolysis and air capture of carbon dioxide, an even less proven technology, making synthetic hydrocarbons even more risky. Renewable natural gas supplies are also likely to be limited, given that most significant sources, like landfills and anaerobic digestion of animal waste, have

[94] https://www.sciencedirect.com/science/article/pii/S0360319921005838.
[95] IRP at 154.
[96] M. W. Melaina, O. Antonia, and M. Penev, "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues," (March 2013), *available at* https://www.energy.gov/sites/prod/files/2014/03/f11/blending_h2_nat_gas_pipeline.pdf.
[97] IRP at 148.
[98] IRP at 118.

already been fully tapped.[99] Moreover, as other sectors of the economy decarbonize, there is likely to be competition for those scarce supplies from sectors in which there are even fewer economic alternatives to hydrocarbons.

In short, by betting on the economic feasibility of using alternative fuels PNM is not only taking on the economic risk of new combustion turbines being a stranded asset, but also a reliability risk if the alternative fuels are unavailable and the combustion turbines are not able to operate.

C. Reliability and economic assumptions caused PNM to choose the wrong resource additions

If PNM accurately modeled the capacity value synergies among wind, solar, and storage, a mix of those resources would have been deployed sooner as the economically optimal way to meet power system energy, capacity, and emissions needs. PNM's proposal to build large amounts of renewables in 2040 misses the opportunity to meet capacity needs while providing large emissions and cost savings in the near term. However, because PNM understated the capacity value of wind and solar, EnCompass built a large amount of storage to meet capacity needs in the "no new combustion" case, resulting in a marginal reduction in emissions at significant cost. The cost and emissions of the "no new combustion" case would have been much lower with new wind and solar providing low-cost, zero-emission energy, as well as being properly credited for meeting capacity needs.

Despite those flaws, the "no new combustion case" costs only 2.7% more than the "technology neutral case" (which builds new combustion turbines) in the current trends and policy future, and even less in the aggressive environmental regulation and low economic growth cases.[100] With either a significant carbon price or a high gas price, the technology neutral case's economic advantage over the no new combustion case is reduced by 42%.[101] Of course, correcting the flawed reliability and economic assumptions would result in a different no new combustion portfolio, with larger amounts of low-cost wind and solar, that almost certainly offers superior economics and reliability when compared to the addition of combustion turbines.

Just as understating the capacity value of wind and solar drives the addition of uneconomic storage capacity in the "no new combustion" case, this flaw drove the addition of uneconomic combustion turbines in the technology neutral case. In every modeled sensitivity of the technology neutral case, the capacity factor for all existing and new combustion turbines is below 10% in every year between now and 2040.[102] Moreover, in the "current trends and policy" future the capacity factor drops to 1% in 2040. The levelized cost of energy for a resource with such a low capacity factor is exorbitant, as the capital and other fixed costs must be recovered from an extremely small amount of generation. EnCompass is clearly building these capital-intensive uneconomic resources to meet a perceived, but imaginary, capacity need. Removing that imaginary capacity need by accurately accounting for the capacity contributions of renewables, storage, and imports would result in a superior portfolio with more renewables and storage and few or no combustion turbines.

[99] https://www.mjbradley.com/sites/default/files/RNGSupplyandBenefits07152019.pdf at 3.
[100] Appendix J.
[101] Based on calculations from PNM scenario cost data provided in Appendix J.
[102] IRP at 154.

INTERWEST ENERGY ALLIANCE

September 7, 2022
Electronically Submitted to IRP@pnm.com

Nick Phillips
Director, Integrated Resource Planning
Public Service Company of New Mexico
Albuquerque, NM

Dear Nick:

Interwest Energy Alliance submits the attached comments in response to your request for input on issues involved in PNM's integrated resource planning process.

Interwest appreciates PNM's interest in hearing from its IRP participants on issues raised in its public advisory meetings. Interwest has been an active participant in the IRP public advisory process and looks forward to upcoming meetings on key issues. Our previous verbal and written comments have focused on correlated generator outages and transmission expansion.

Our attached written comments focus on the benefits of transmission expansion for PNM and its customers. That point is emphasized by our understanding that PNM was able to sell into the western market this week at favorable prices benefiting PNM's customers, which helped California meet its customers' peak power needs during the unprecedented heat event which struck California this week. This mirrors the benefits PNM's customers received from PNM's ability to obtain limited amounts of power from other western regions during New Mexico's heat and power peak in July this year. Transmission expansion to enhance regional marketing opportunities to realize financial and reliability benefits is clearly of value to PNM and its customers, and should play an important part in PNM's resource planning process.

We understand the upcoming September 13 IRP public advisory meeting on will focus on transmission planning, and we look forward to participating. We hope PNM will take our comments into consideration, post them on PNM's IRP webpage, and circulate them to other participants for their consideration in advance of the September 13 meeting.

Thank you again for your outreach efforts in your IRP planning process and willingness to consider participant input. We welcome the opportunity to engage in discussions on these and other key IRP issues to assist PNM in developing a strong and well supported IRP.

Sincerely,

Rikki Seguin

Rikki Seguin
Executive Director

Attachment

Comments of the Interwest Energy Alliance

Public Stakeholder Process

Public Service Company of New Mexico 2023 IRP Process

September 7, 2022

Introduction

The Interwest Energy Alliance fully participates in many state and regional forums to provide input related to generation and transmission resource planning, including throughout WestConnect, and also actively supports transmission expansion in CPCN approval dockets throughout the Rocky Mountain West and Southwest. Interwest sees firsthand the benefits of transmission expansion and the real and specific opportunity costs that exist from lack of access to diverse generation resources. Interwest consistently recommends that resource planning be fully integrated, to include generation and transmission planning, and has done so in the rulemakings in New Mexico as well as several rounds of resource planning by PNM and other utilities across the region. Interwest submits these comments as a reminder that increasing regional coordination and integrated planning will decrease costs, increase reliability, and increase benefits to the people of New Mexico for generations. Interwest looks forward to helping to support any transmission expansion which will provide these benefits when PNM moves to obtain approval from regulating bodies with jurisdiction over these applications when these benefits and the costs can be appropriately recognized.

These comments do not encompass the full view of Interwest on every issue touched upon by this IRP process but are the issues that Interwest believes should be addressed at this stage.

Prior IRP Docket

In PNM's 2021 IRP, docket 21-00033-UT, Interwest, jointly with NMAREA, submitted a whitepaper in September 2021 authored by Michael Goggin of Grid Strategies, LLC, addressing the reliability and economic inputs and outputs of the IRP process. PNM has capably addressed several of our concerns in this IRP iteration, but there are still areas of concern that Interwest believes should be addressed.

In the Final Order dated July 13, 2022, the Commission states at paragraphs 22 and 23:

> *22. However, the Commission also concurs with NMAREA and Interwest that PNM should address distribution and transmission planning in a meaningful way in its upcoming 2023 IRP filing because while PNM's April 27th Update expressly acknowledged that transmission constraints limit its resource adequacy and availability, PNM's current 2020 IRP fails to even start to address the issue in a meaningful way. The Commission finds that PNM's continuing delay in even starting to address them will result in further prolonging these constraints on PNM's resource and reliability options. The Commission finds PNM's 2023 IRP Action Plan should include an action item that identifies and analyzes distribution and transmission constraints and opportunities.*

> *23. For this reason, the Commission finds that PNM should include, in its future 2023 IRP filing a meaningful analysis of transmission and distribution constraints and opportunities to increase resource availability and flexibility. The Integrated Resource Planning statute Section 62-17-10 NMSA 1878 specifically requires that the Commission can require utilities include, in their IRPs to address load management and there is no way to plan for load management without looking at transmission and distribution. Further, given that transmission and distribution are significant capital expenditures going forward and presently, these costs make up a large part of an IRP that need to plan for the "most cost-effective portfolio" of resources.*

It is in these areas that we focus our comments today.

PNM must account for the benefits of new transmission

Increased transmission, when planned correctly, can provide multiple benefits and lower costs, including during those periods when natural gas supply is most at risk. Traditional transmission planning often under-values the benefits of transmission to provide resilience and recovery during extreme weather events. Portions of these benefits are shown below:

Extreme conditions and high-value periods, which are difficult to model, play an outsized role in the value of transmission

- 50% of transmission's congestion value comes from only 5% of hours.
- Existing transmission planning approaches run the risk of understating the economic value of new transmission infrastructure by inadequately modeling such periods.
- These findings are driven not only by historical weather events but also 'normal' market occurrences such as infrastructure outages, fuel price volatility, forecast errors, and electric demand volatility.

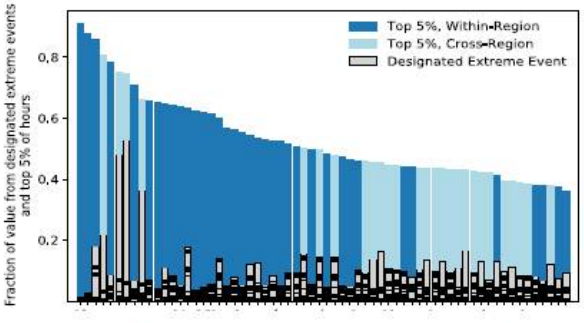


Figure 3: Fraction of marginal congestion relief value in top 5% of hours and during designated extreme events from 2012 through 2021. Each bar represents a different link represented in Figure 1. The specific path labels of the transmission links are found on slide 28.

[1]

The lack of integration between transmission planning and resource planning increases costs and decreases regional reliability. Although FERC is currently addressing some of these concerns through ongoing Notices of Proposed Rulemaking (NOPRs) related to transmission planning, generator interconnection, and accounting for severe weather in transmission planning, PNM has

[1]D. Millstein, R. Wiser, W. Gorman, S. Jeong, J. Kim, A. Ancell, Empirical Estimates of Transmission Value
using Locational Marginal Prices, Lawrence Berkeley National Laboratory, 2022. Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

the opportunity, and the obligation, to increase this integration and provide the maximum benefits to New Mexico ratepayers in its resource planning.

Recently, FERC Chairman Glick and Commissioner Clements issued a joint statement to this effect:

> *[W]e are also concerned that the current approach to transmission planning and cost allocation is failing to adequately identify the benefits and allocate the costs of new transmission infrastructure. […] As a result, the status quo may be disproportionately producing transmission facilities that address a narrow set of needs, providing comparatively modest benefits, but at a still-substantial total cost instead of developing the type of transmission infrastructure that could provide the most significant benefits for customers*.[2]

Additionally, in the ongoing NOPR on transmission planning (RM21-17), FERC has recently elucidated 12 categories of transmission benefits that should be included in transmission planning, and Interwest believes that they would be equally valuable to consider in the resource planning process. These are:

- Avoided or deferred reliability transmission projects and aging infrastructure replacement
- Either reduced loss of load probability or reduced planning reserve margin
- Production cost savings
- Reduced transmission energy losses
- Reduced congestion due to transmission outages
- Mitigation of extreme events and system contingencies
- Mitigation of weather and load uncertainty
- Capacity cost benefits from reduced peak energy losses
- Deferred generation capacity investments
- Access to lower cost energy
- Increased competition
- Increased market liquidity

These factors are just as vital when making decisions about intrastate transmission needs as they are for more regional decision-making. By addressing all or most of these categories of benefits in both transmission planning and resource planning, PNM would be able to create a paradigm wherein these planning processes would complement each other and create robust evidence for projects that provide the greatest benefits. Portions of these benefits are shown below:

[2] Joint Statement from Chairman Glick & Commissioner Clements on Building Transmission for the Future, Federal Energy Regulatory Commission, July 2021, available at https://www.ferc.gov/newsevents/news/joint-statement-chairman-glick-commissioner-clements-building-transmission-future.

Transmission Links Have Significant Economic Value

- Interregional and regional transmission links reduce congestion and expand opportunities for trade.
- Nodal real-time wholesale power prices exhibit stark geographic differences that are, in many cases, stable overtime and can be used to estimate transmission value.
- Many links have hourly average pricing differences that exceed $15/MWh – equivalent to $130 million per year for a 1000 MW link.
- Interregional links ($24/MWh in the median case in 2021) have greater value than regional links ($11/MWh in the median case in 2021) – though many high-value regional links exist.

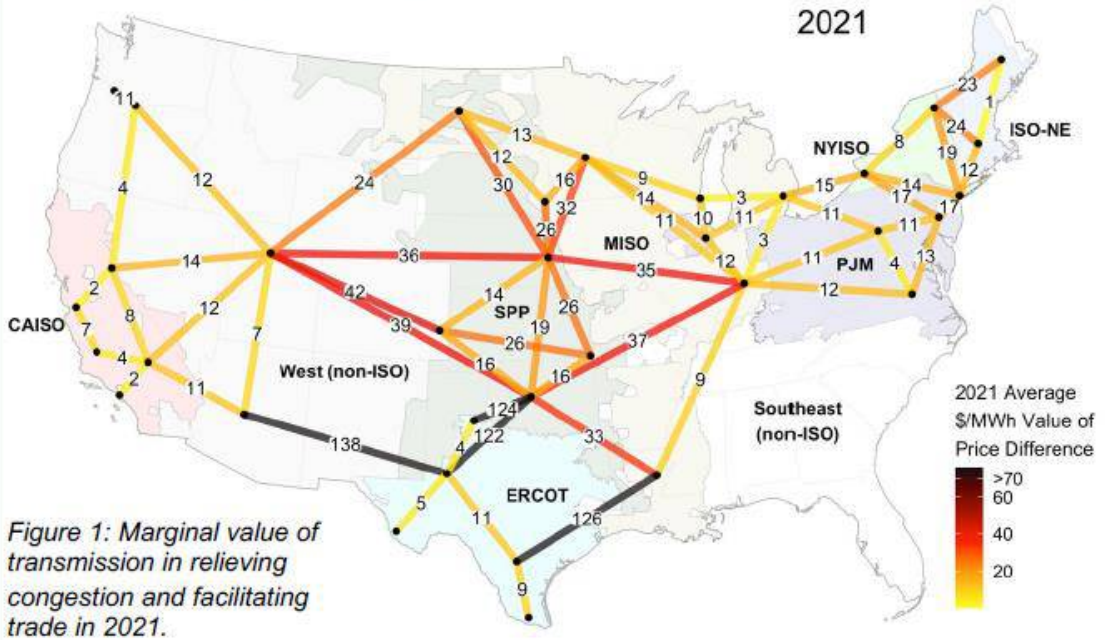


Figure 1: Marginal value of transmission in relieving congestion and facilitating trade in 2021.

[3]

PNM should allow new wind in its modeling

It is not reasonable to put forth the chicken-or-the-egg argument that new wind resources are not economic due to the need for additional transmission to access those resources, while also not including a robust transmission plan that could access these resources and assign accurate costs. Allowing the model to pick both wind resources and transmission is the only way to accurately understand the relationship between these costs and benefits. Transmission, if planned

[3] D. Millstein, R. Wiser, W. Gorman, S. Jeong, J. Kim, A. Ancell, Empirical Estimates of Transmission Value using Locational Marginal Prices, Lawrence Berkeley National Laboratory, 2022. Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

holistically, could access cost-effective New Mexico wind resources and provide multiple benefits for the cost.

Additional wind resources, even with associated transmission costs, are quite likely to be economic. This is borne out by the understanding that hundreds or even thousands of megawatts of New Mexico wind are currently being planned and built for Arizona and California access. If New Mexico wind is an economic resource for utilities and customers hundreds of miles away, it is exceedingly likely that the same would be true for customers in the PNM service territory. PNM should appropriately include this opportunity in modeling.

Multiple Benefits of Transmission

1. Reliability

Expanding the transmission system provides substantial benefits to PNM by accessing geographically diverse sources of electricity supply and demand. First, a more geographically diverse fleet of renewable resources reduces their variability and delivers a more consistent energy output, increasing their capacity value. PNM can achieve this both by building transmission to access diverse renewable resources on its own system and increasing ties to neighboring power systems to increase transfer capacity for market imports and exports. As our 2021 IRP comments explained, NREL and other experts have found that greatly expanded transmission ties are essential for cost-effective decarbonization because they tap into the geographic diversity of renewable output across larger regions. Even a relatively small amount of geographic distance between two renewable plants is enough for the output profiles of wind[4] or solar plants[5] to be less than perfectly correlated, as local weather phenomena no longer affect both plants simultaneously. These diversity benefits reduce the cost of operating the power system, as lower variability reduces the need for additional flexible resources to quickly change their level of output.[6]

Second, expanded ties to neighboring power systems reduce PNM's exposure to correlated conventional generator outages on its own system, particularly those caused by localized severe weather events. In particular this reduces the likelihood of catastrophic results from correlated gas unit outages, as discussed by Michael Goggin at the PNM IRP meeting on August 17, 2022. As Winter Storm Uri demonstrated, the lack of interconnections doomed ERCOT to blackouts while MISO and SPP, both experiencing the same weather conditions, were able to rely on imports from their neighbors to prevent large-scale rolling blackouts.[7] Recent analysis by Lawrence Berkeley National Laboratory found that "roughly half of the marginal value of

[4] H. Holttinen, et al., Design and Operation of Power Systems with Large Amounts of Wind Power, 2009, available at https://community.ieawind.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=c7a0f97c-b01c-713b-b51a-46f33d62b5db&forceDialog=0.

[5] A. Mills, R. Wiser, Implications of Wide-Area geographic Diversity of Short-Term Variability of Solar Power, Lawrence Berkeley National Laboratory, September 2010, available at: https://emp.lbl.gov/sites/all/files/presentation-lbnl-3884e-ppt.pdf.

[6] K. Van Horn, J. Pfeifenberger, P. Ruiz, The Value of Diversifying Uncertain Renewable Generation through the Transmission System. Boston University Institute for Sustainable Energy, 2020. Available at https://www.bu.edu/ise/files/2020/09/value-of-diversifying-uncertain-renewable-generation-through-the-transmission-system-093020-final.pdf.

[7] M. Goggin, Transmission Makes the Power System Resilient to Extreme Weather, July 2021, available at https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

transmission in providing congestion relief occurs during extreme grid conditions and high-value periods that account for only five percent of hours but are challenging to model and so are often not fully considered in transmission planning."[8]

Third, and potentially most importantly, larger interconnections to other utility systems tap into geographic diversity in electricity demand, reducing capacity needs because across a region, utilities experience peak demand at different times, mostly due to geographic diversity in weather and climate.

Grid Strategies, LLC recently quantified renewable and load diversity across the Southwestern U.S. using publicly available Energy Information Administration (EIA) data. By comparing stand-alone versus regionally aggregated 2021 EIA hourly load and renewable generation data for Balancing Authorities across the Southwest,[9] the analysis shows a large reduction in peak capacity needs from aggregating diverse loads and renewable resources across the region. Specifically, the Southwest could see a reduction in peak net load of over 8% or 8,500 MW, with adequate transmission and a regional resource adequacy construct like the one being developed by the Western Power Pool.[10] This translates to $7 billion in savings if the benefit were realized through a reduced need for new gas combustion turbine capacity.[11] Aggregating across the entire U.S. portion of the Western Interconnect reduces peak net load by 14% or 19,400 MW, which could displace $16 billion in costs for generating capacity. Notably, this analysis does not account for the additional benefit from how weather and climate diversity reduce correlations in conventional generator outages and derates across large areas, as the hourly generator outage and derate data needed to quantify that benefit is not publicly available. Portions of these benefits are shown below:

Transmission value is correlated with energy prices and varies by region and year

- Congestion has gotten worse for links connected to SPP and ERCOT.
- Value of transmission is variable overtime, and often spikes in the event of extreme conditions like the 2014 Polar Vortex and 2021 Winter Storm Uri.

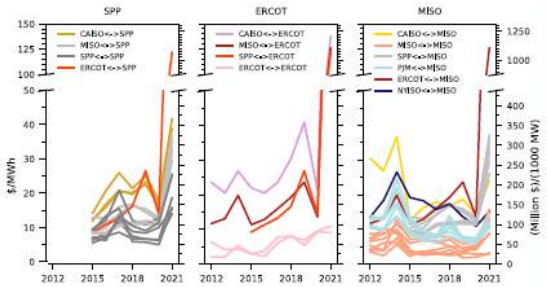


Figure 2: Marginal value of transmission overtime for links across a subset of ISOs/RTOs.

[12]

[8] https://emp.lbl.gov/news/regional-and-interregional-transmission-have.
[9] Data available at https://www.eia.gov/electricity/gridmonitor/sixMonthFiles/EIA930_BALANCE_2021_Jan_Jun.csv, https://www.eia.gov/electricity/gridmonitor/sixMonthFiles/EIA930_BALANCE_2021_Jul_Dec.csv.
[10] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program
[11] Conservatively using an assumed $785/kW cost of a frame combustion turbine from U.S. Energy. Info. Admin., *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022* (Mar. 2021), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf, and the conservative assumption that a new combustion turbine offers 95% of its nameplate capacity as dependable capacity value.

[12] D. Millstein, R. Wiser, W. Gorman, S. Jeong, J. Kim, A. Ancell, Empirical Estimates of Transmission Value

The Western Flexibility Assessment[13] (WIEB Study) similarly demonstrated that system flexibility can be achieved by integrating several strategies to include resource mix diversity, additional transmission, storage, load management, and enhanced market co-ordination.

2. Markets

Finally, access to markets is a natural extension of the more and larger interconnection opportunities discussed above. The WIEB Study also shows that if a regionally coordinated market, supported by enhanced transmission, is not developed then there could be severe consequences over the next decade. More specifically, curtailments would double, there would be an increase in production costs by $1.3 billion per year, and an increase in CO2 emissions.[14] A recent study from Boston University showed that when two regional systems/submarkets with different renewable resource production profiles are interconnected there can be a reduction in annual production costs between 2% to 23% and a decline in annual renewable curtailments between 45% to 90%.[15]

Utilities in the Western Interconnect are pursuing markets in a way that has never been seen before, and PNM must, like all western utilities, adapt to this changing environment. Real-time markets, both the EIM and WEIS, have almost universal coverage of the Western Interconnect at this point. Day-ahead markets may be available for PNM to join soon. PNM has not made public statements or been actively engaged in the development of SPP's Markets + or the CAISO EDAM based on a high-level review of submitted comments. If PNM has been engaged, it would be helpful to stakeholders to understand how planning may be affected by the increased access to new sources of generation and diverse load to be served by PNM. Similarly, PNM should participate in the Western Power Pool's Western Resource Adequacy Program. PNM, like all western utilities, is at somewhat of a crossroads to begin the process of choosing between regional wholesale markets, the boundaries of which may determine substantial costs and benefits. Increased access to low-cost western resources could lower costs overall and Interwest and other stakeholders would appreciate more information on PNM's endeavors so that we can support PNM's efforts in this regard.

Thank you for accepting these written comments and Interwest looks forward to discussing these issues at the scheduled September 13, 2022 IRP public stakeholder meeting and continuing these discussions going forward.

Interwest Energy Alliance

---

using Locational Marginal Prices, Lawrence Berkeley National Laboratory, 2022. Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

[14] B. Brownlee, G. Simonson, K. Fraser, D. Ramirez, C. Liotiris, K. Moyer, Western Flexibility Assessment: Investigating the West's Changing Resource Mix and Implications for System Flexibility, Energy Strategies, 2019. Commissioned by the Western Interstate Energy Board. Available at https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf.

[15] K. Van Horn, J. Pfeifenberger, P. Ruiz, The Value of Diversifying Uncertain Renewable Generation through the Transmission System. Boston University Institute for Sustainable Energy, 2020. Available at https://www.bu.edu/ise/files/2020/09/value-of-diversifying-uncertain-renewable-generation-through-the-transmission-system-093020-final.pdf.

PNM 2023-2042 IRP: Public Advisory Group Day

STEERING MEETING #4

AUGUST 17, 2022



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

MEETING GROUND RULES

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP

01 

- Questions and comments are welcome – One Person Speaks at a Time

02 

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

03 

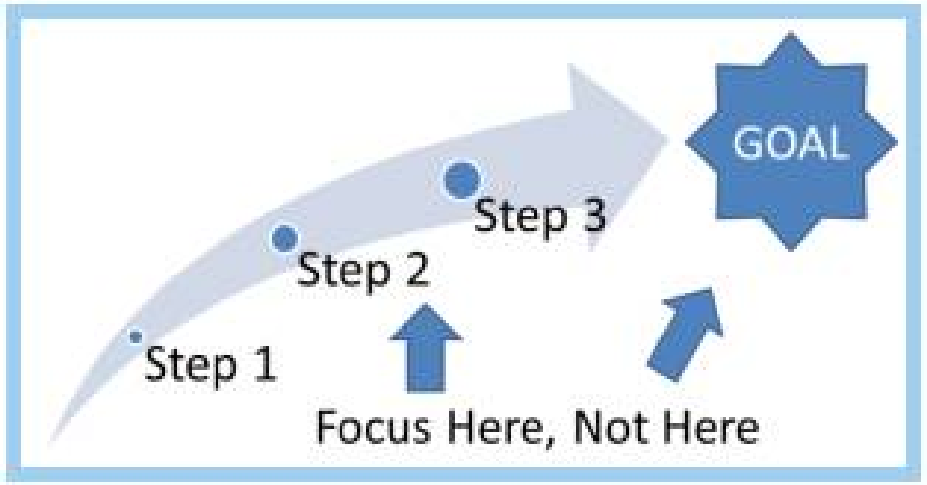
- When asking a question, please speak clearly and slowly as all questions will be logged and labeled with the person and organization responsible for asking the question

04 

- These meetings are about the 2023 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing.

PNM Talk to us. PNM.com

THE FOCUS OF THE MEETING IS THE DEVELOPMENT OF THE 2023 IRP



The technical sessions are about discussing the advantages and disadvantages regarding the application of different technical methodologies within the IRP modeling framework.

We are not here to focus on the results or drive towards a specific result. **We all know where we are going: 100% Carbon Free by 2040. The focus in the IRP development is how do we get there in the best way possible for PNM's customers and New Mexico.**

MEETING AGENDA

- Welcome and Introductions
- Presentation – Grid Strategies (Michael Goggin)
- Next steps and Near-Term Schedule

Potential methods to account for correlated generator outages

Michael Goggin

Grid Strategies LLC

August 17, 2022



Methods for accounting for correlated outages and derates of conventional generators

- Correlated conventional generator outages due to equipment failures and fuel supply interruptions have played a major role in recent reliability events.
- Effective Load Carrying Capability (ELCC) methods capture correlations in output patterns for renewable and storage resources. Conventional generators also exhibit correlated outages and derates, but those are not typically accounted for.
- Ignoring conventional generator correlated outages can bias resource selection, and mask reliability risk.
- Grid operators and others have developed methods for evaluating risks to resource adequacy and resilience from correlated conventional generator outages and derates.
- Some methods apply ELCC to conventional generators using historical patterns for generator outages.
- Other methods focus more on testing a large number of potential generation mixes under a range of plausible conditions.

Astrape "Accrediting RA Value to Thermal Gen"

		Winter Accreditation Impact	Winter Capacity Credit[1]	Summer Accreditation Impact	Summer Capacity Credit
Standard Accounting Practice	Forced Outage Rate	5.0%	95.0%	5.0%	95.0%
Proposed Additional Considerations	Outage Variability	2.7%	92.3%	4.6%	90.4%
	Outage Correlation	2.3%	90.0%		
	Weather Dependent Outages	10.0%	82.3%[2]	5.6%	84.7%
	Fuel Supply Outages[3]	6.2%	76.1%[4]		

Astrape found that accounting for correlations in conventional generator outages due to equipment failures and fuel supply interruptions significantly reduced their capacity value. In summer the capacity value was reduced from 95% to 85%, and in winter to 76%. This analysis was done for PJM South (Dominion's footprint in Virginia and parts of West Virginia and North Carolina), but could be done for other regions.

https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf

Ideas explored as part of MISO moving to Seasonal RA

- As it was developing a seasonal resource adequacy approach, MISO explored ways to account for correlated outages in both testing system LOLE and accrediting capacity value to resources.
- In SERVM modeling of system LOLE, “an adjustment will be applied within the model to account for increased forced outages during extreme weather events. When the temperature drops below a certain threshold in the model, the outage rates for thermal resources will be increased to represent the correlation between extreme temperatures and forced outages.”
- Capacity value accreditation would be based on historical performance during tight system conditions, and class averages would be applied to new resources.

https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20Seasonal%20RA%20Conceptual%20Design%E2%80%93Report.pdf

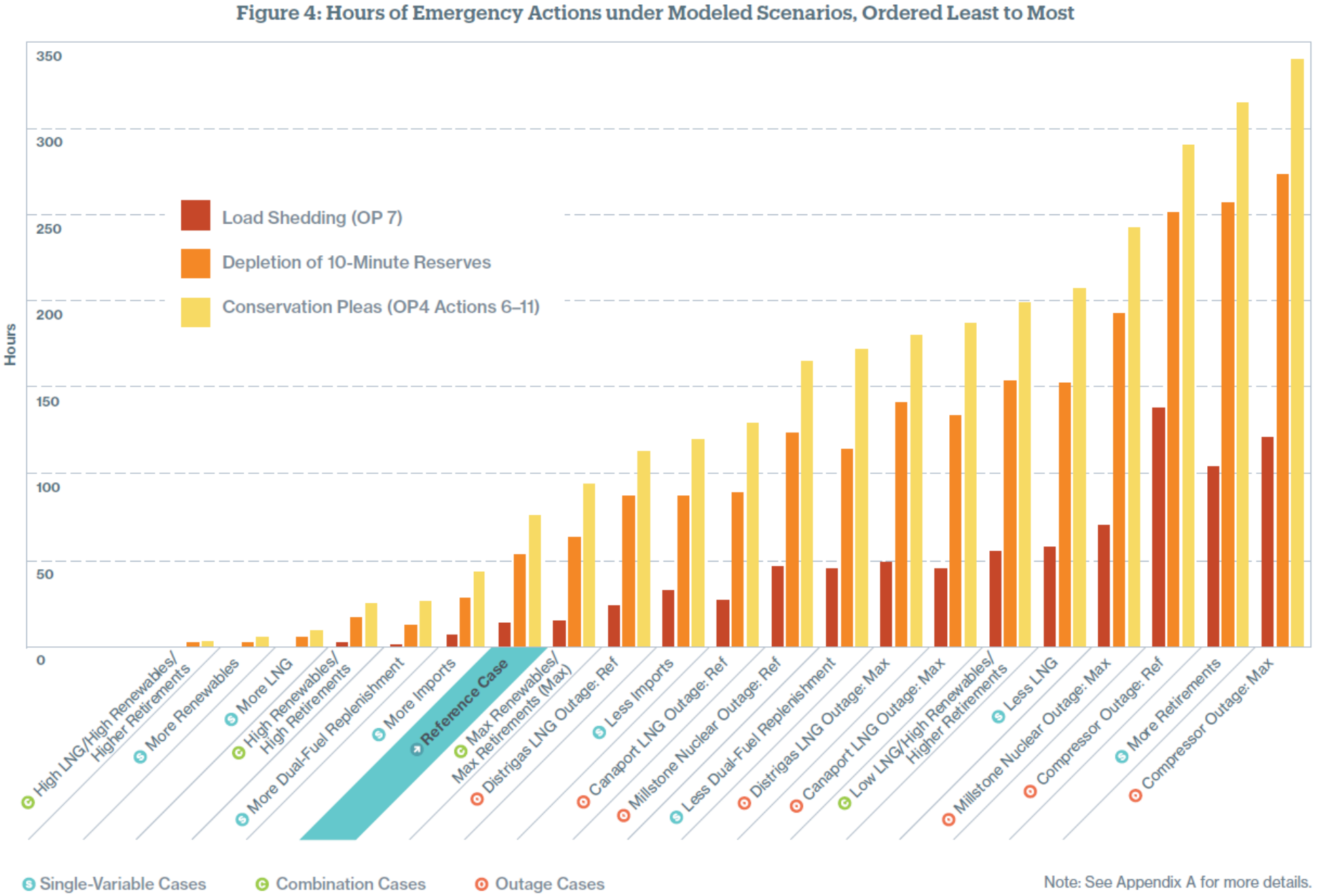
"PJM's Evolving Resource Mix and System Reliability"

- First PJM conducted a risk analysis in which hundreds of potential generation mix "portfolios were assessed for their ability to provide the generator reliability attributes … under four operational states: normal peak conditions, light load, extremely hot weather and extremely cold weather."
- *The resilience of the portfolios identified as desirable by the risk analysis was tested by subjecting the desirable portfolios to a polar vortex event. Such an event may trigger higher-than-average unavailability rates for fuel types such as natural gas, coal and solar. To determine these potential higher-than-average unavailability rates, generator performance data from high load days during Winter 2014/2015 and Winter 2015/2016 were analyzed by fuel type. The maximum unavailability rates during those days were applied to the portfolios in the desirable region. Reliability indices and composite reliability indices were recalculated.*
- *Only 34 of the 98 portfolios which were classified as desirable were resilient when subjected to a polar vortex event. This sensitivity specifically captured the increased risk of natural gas delivery under extremely cold and high load conditions. The polar vortex sensitivity highlights the importance of resilience, which is not captured by the generator reliability attributes that were considered in this study.*



https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

ISO-NE "Operational Fuel-Security Analysis"



ISO-NE tested its ability to meet winter demand under 23 scenarios that varied the generation mix, generator outages, and gas supply outages.

https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

NERC 2017 Special Reliability Assessment

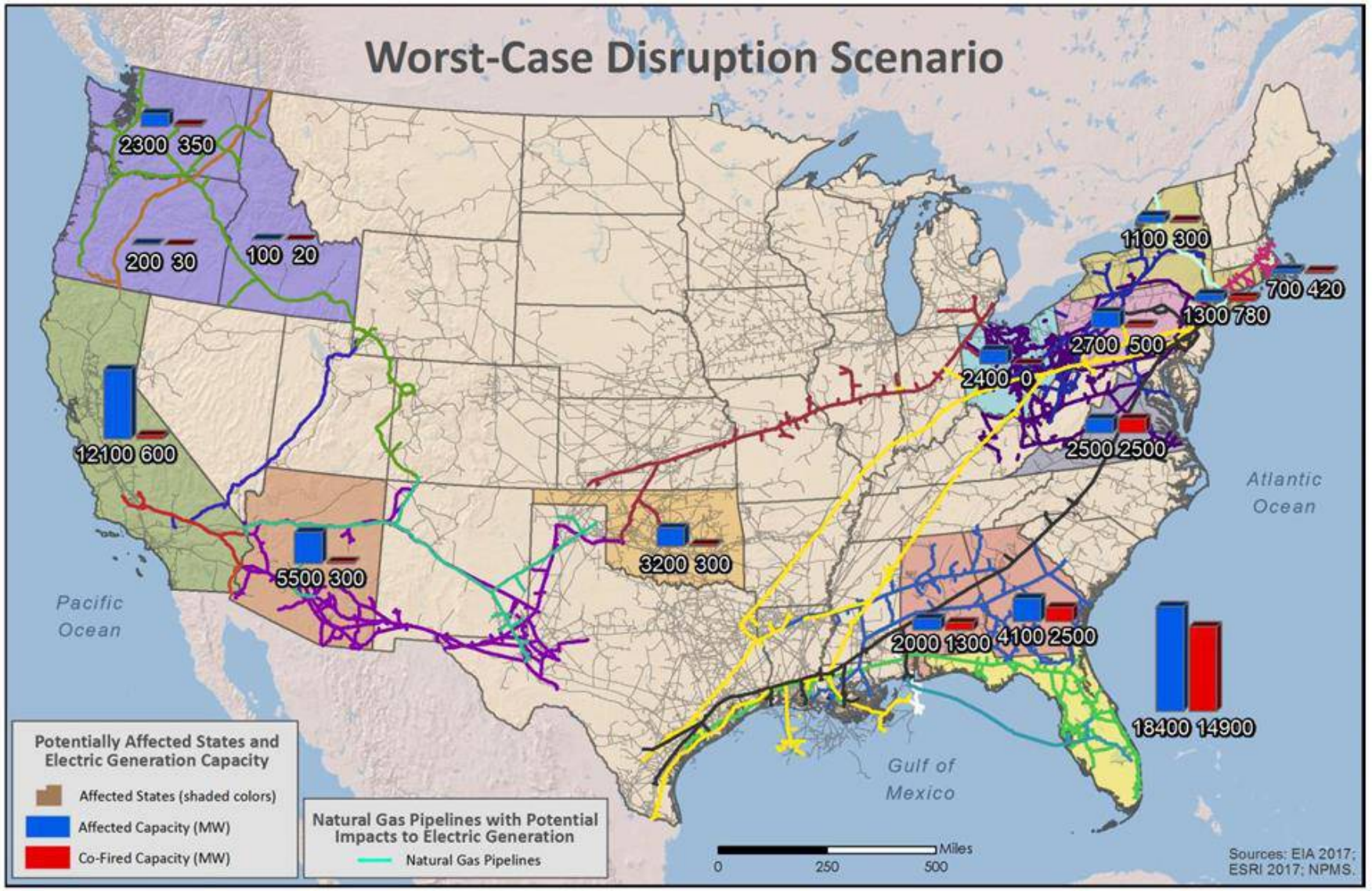


Figure E.2: Summary of NGfast Simulation Results for the Worst-Case Scenario

An Argonne National Laboratory tool (NGfast) was used to model the amount of gas generating capacity that could be taken offline by potential disruptions to the interstate gas pipeline system.

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

QUESTIONS/COMMENTS

WE WOULD LIKE TO HEAR FROM YOU

Any comments or questions regarding any of the topics PNM has previously presented?

Any feedback regarding any of drivers/assumptions that will be used in the 2023 IRP?

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: August 31, 2022

Topic: Public Advisory Steering Meeting #5: Emerging/Evolving Grid Solutions

Start Time: 9:00 AM

Location: Virtual

PNM will hold virtual meetings until circumstances warrant a change. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEAR TERM SCHEDULE

FUTURE MEETING TIME & LOCATION

When: September 15, 2022

Topic: Public Advisory Steering Meeting #6: Transmission

Start Time: 9:00 AM

Location: Virtual

PNM will hold virtual meetings until circumstances warrant a change. If there is strong interest to resume in person meetings for future sessions, please email us at IRP@pnm.com. We will continue to notify everyone through the email service list regarding upcoming meeting dates, topics and locations (virtual or in person).

NEXT MEETING

We encourage you to send in your thoughts ahead of time to IRP@pnm.com so that we can summarize them and distribute them for the next meeting. Please have your submissions in by August 29, 2022.

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



GRIDWORKS

Stakeholder Meeting for PNM Integrated Resource Plan

PURPOSE: Incorporate stakeholder input on the Statement of Need and Modeling (which informs input to the Action Plan).

WHEN: Thursday, May 18, 2023

TIME: 9:00 – 10:30 AM MDT

WHERE: WEBEX. Please register via the PNM IRP Website

Schedule & Registration (pnmforwardtogether.com); or
https://www.pnmforwardtogether.com/schedule-and-events

Schedule & Registration

Participate in PNM's current IRP process.

Listen to PNM and stakeholder presentations regarding grid planning, load forecasting, environmental energy considerations, and more.

Ask questions. PNM welcomes all public commentary and questions.

Suggest solutions. PNM actively seeks solutions to our common challenges from all stakeholders, including public interest groups, individuals, and scientific, environmental, or special-interest organizations.

Register at the links below to be part of planning for a reliable, cost efficient, and clean energy future.

Date	Topics / Presentation(s)	Register
May 4, 2023	Stakeholder Grounding Workshop for PNM Integrated Resource Plan (gridworks.org)	Register
May 18, 2023	IRP Stakeholder Meeting #3	Register

HOW CAN I PREPARE: Read-ahead information is being posted as it becomes available at New Mexico Energy Planning – Gridworks. Materials include the Statement of Need outline, the draft Modeling Engagement Plan, a list of modeling topics collected to date, and the data request NDA.

AGENDA

9:00 AM – Welcome, purpose and outcomes for the session. Identify newcomers.

9:05 AM – Statement of Need: discuss outline prepared by the group of volunteers and invite comments

9:40 AM – Proposed Modeling Engagement Plan and Formation of Modeling Core Team

10:15 AM – Next steps and feedback

10:30 AM - Adjourn

Welcome!

Stakeholder Engagement Meeting

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, May 18

9:00 AM Mountain Daylight Time

Purpose of Today's Meeting

- Our primary objective is to incorporate stakeholder input while advancing our two work products
- Discussion topics include:
  - Statement of Need Outline and next steps
  - Modeling Engagement Plan Feedback and formation of Modeling Core Team
  - Next meeting/workshop

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Stakeholder Engagement is Progressing to Phase 2

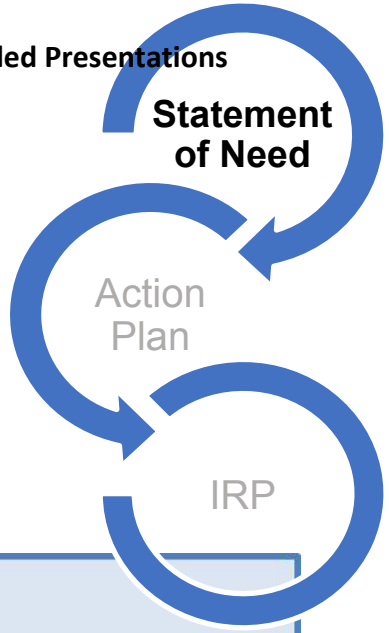
March – May	June – August	Sept – Nov

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

Statement of Need Defined by the IRP Rule



Statement of Need 17.7.3.10

- 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.
- 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.

Statement of Need Outline

- Review of SoN Outline by volunteer group
- Discussion
  - What words or concepts caught your attention?
  - What is missing? What changes are needed?
- Next Steps (create content), share with stakeholders for June 1 review

Statement of Need Outline

1. Introduction
2. Vision and Goals
3. Current and Expected System Conditions
4. Identified Decision Points and Pathways
5. Resources

Modeling Engagement Plan and Core Team

- Describe key elements and timeline
- Propose core team members
- Invite additional suggestions for core team
- Collect feedback on plan
- Determine next steps



A Deeper Dive into Phase 2

March – May	June – August	Sept – Nov

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

NEXT DEADLINES

May 26 - Model run requests and prioritization criteria suggestions due to mtatro@gridworks.org

June 15 - Latest date to request access to modeling information (public or confidential via NDA)

SCHEDULED MEETINGS

- June 1 – Review SoN, vote on model run prioritization criteria
- June 15 – Check consensus on SoN, discuss results of PNM scenarios modeling and short list of MCEPs which will require additional analysis. Decisions on stakeholder requested additional model runs as recommended by modeling core team.
- June 29 – Full day focused on modeling results (by PNM and others) and candidate action plan suggestions. Discuss need for additional SERVM runs.
- July 13 – Results of prioritized stakeholder requested runs. Discuss and improve action plan input. Decide on additional SERVM runs, if necessary.
- Aug 17 – Review results of additional modeling runs. Refine input to action plan.

We are Interested in your Feedback

Take the Feedback Survey by…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

CONFIDENTIALITY AGREEMENT

THIS CONFIDENTIALITY AGREEMENT ("Agreement") is effective as of _____, 2023 ("Effective Date") and is by and between **Public Service Company of New Mexico,** a New Mexico corporation ("PNM") and _____ ("Recipient"). PNM and Recipient may be referred to in this Agreement individually as a "Party" and collectively as the "Parties."

WHEREAS, the Recipient wishes for PNM to perform one or more modeling runs or to provide data or other information as part of the integrated resource planning facilitated stakeholder process, as provided for by 17.7.3.9 NMAC, and for PNM to share all resultant modeling reports and information ("Authorized Purpose"); and

WHEREAS, PNM may release Confidential Information (as defined below) to Recipient in connection with the Authorized Purpose; and

WHEREAS, PNM has engaged with and received Confidential Information (as defined below) from one or more consultants, including but not limited to Anchor Power Solutions, Horizons Energy LLC, and Astrapé Consulting LLC in connection with the Authorized Purpose; and

WHEREAS, employees, affiliates, subcontractors, or any other representatives of any entity that either is currently, or in the future will likely be, actively participating in wholesale electric energy transactions or PNM competitive solicitation for resources shall not be eligible to receive the Confidential Information; and

WHEREAS, Recipient wishes to receive the Confidential Information and agrees to keep such Confidential Information confidential in accordance with the terms of this Agreement.

NOW, THEREFORE, in consideration of the mutual covenants, terms and conditions set forth in this Agreement, PNM and Recipient agree as follows:

1. Confidential Information. "Confidential Information" shall mean all non-public information, regardless of the form in which it is communicated or maintained (whether oral, written, electronic or visual) and whether prepared by PNM or otherwise, which is disclosed to Recipient, regardless of whether such information is disclosed before or after the execution of this Agreement, in connection with the Authorized Purpose and including but not limited to all records, reports, proposals or other responses to requests for proposals and/or information, analyses, notes, memoranda, documentation, data, specifications, diagrams, statistics, systems or software, manuals, business plans, operational information or practices, processes (whether or not patented, patentable or reduced to practice), customer lists, contractual arrangements with, and information about, PNM's suppliers, distributors and customers, the existence of the discussions between the Parties concerning the Authorized Purpose, or other information that is based on, contains or reflects any such Confidential Information. All information received from PNM shall be considered Confidential Information, unless it is specifically designated as non-proprietary and non-confidential. For the avoidance of doubt, the Confidential Information specifically includes data disclosed by or through PNM, its parent, its affiliates, or their respective officers, directors, employees or representatives.

2. Protection and Use of Confidential Information.

(a) Recipient shall use the Confidential Information only for the Authorized Purpose;

1

(b) Recipient shall not disclose the Confidential Information to any other person or entity (except to the employees or contractors of Recipient or those of its affiliates, in accordance with the terms of this Agreement) without the prior written consent of PNM;

(c) Recipient shall not make any copies of the Confidential Information except as is specifically needed for and directly related to the Authorized Purpose, and in the event such copies are made, all copies shall be treated in the same fashion as and considered to be the same as the originals for purposes of this Agreement (as Confidential Information), and shall be subject to the terms and conditions of this Agreement; and

(d) Recipient shall safeguard the Confidential Information with the same degree of care to avoid unauthorized disclosure as it uses to protect its own confidential and proprietary information and trade secrets, but in no event less than reasonable care.

3. Exceptions. The obligations of Recipient pursuant to Section 2 shall not apply to any Confidential Information that Recipient can demonstrate:

(a) is or becomes available to the public through no breach of this Agreement;

(b) is received from a third party that is not, and was not, prohibited from disclosing such Confidential Information to Recipient by a contractual or other obligation to PNM;

(c) is independently developed by Recipient without the use of any Confidential Information;

(d) is approved for release by written authorization of PNM, but only to the extent of and subject to such conditions as may be imposed in such written authorization;

(e) is required to be disclosed under applicable stock exchange requirements or to auditors, taxing authorities, or accountants preparing tax reports and filings; or

(f) is required to be disclosed by a government agency to further the objectives of this Agreement, by applicable law, rule or regulation, or by a proper court of competent jurisdiction, including in connection with any approval sought from, filing with, request for information through administrative process of, or compliance obligation imposed by, any governmental authority; provided, however, that Recipient shall first provide PNM reasonable notice of the disclosure deadline as set forth in Section 15 so that PNM has an opportunity to seek to obtain a protective order or other confidential treatment of the Confidential Information.

4. Ownership and Return of Confidential Information. Confidential Information, including all copies thereof, shall remain the property of PNM (or its applicable affiliate). Upon written request by PNM, Recipient shall return to PNM or destroy all Confidential Information received in tangible form (including any copies thereof), within fifteen (15) business days following expiration or termination of this Agreement, unless PNM requests return or destruction of the Confidential Information on an earlier date. Recipient shall also, within five (5) business days of a written request by PNM, certify in writing that it has satisfied its obligations under Sections 2 and 4 of this Agreement.

5. Injunctive Relief. Recipient understands and agrees that an impending or existing violation of

any provision of this Agreement could cause PNM irreparable injury for which it would have no adequate remedy at law, and that PNM shall be entitled to seek immediate injunctive relief prohibiting such violation, in addition to any other remedies available to it at law or in equity. Nothing in this Section 5 or in this Agreement shall prohibit PNM from recovering monetary damages from Recipient for a

violation or breach of this Agreement if a court of competent jurisdiction makes such an award. PNM shall be entitled to recover its attorneys' fees in any action brought by it in respect of any impending or existing violation of any provision of this Agreement or to otherwise enforce the terms of this Agreement, provided PNM is the prevailing party in such action.

6. No Rights or Warranties. Recipient expressly acknowledges and agrees that no patent, copyright, trademark or other proprietary right or license is granted to it by PNM's disclosure of Confidential Information pursuant to this Agreement, except for the right to use such information in accordance with this Agreement. Further, Recipient expressly acknowledges and agrees that PNM is making no warranties of any kind with respect to the Confidential Information disclosed under this Agreement or any use thereof.

7. Term. This Agreement shall be effective on the Effective Date and shall terminate five (5) years from the Effective Date, or thirty (30) calendar days following written notice by either Party to the other of its desire to terminate this Agreement, whichever occurs first. Notwithstanding termination of this Agreement, the obligations to maintain the confidentiality of Confidential Information and strictly comply with the restrictions on use as set forth in this Agreement will survive.

8. Validity and Enforceability. If any provision of this Agreement shall be held invalid or unenforceable, such provision shall be deemed deleted from this Agreement and replaced by a valid and enforceable provision that so far as possible achieves the Parties' intent in agreeing to the original provision. The remaining provisions of this Agreement shall continue in full force and effect.

9. No Guarantee of Further Agreements. This Agreement is not intended to and does not obligate either Party to enter into any further agreements or to proceed with any relationship or other transaction, including in connection with the Authorized Purpose, or to require PNM to disclose any information under this Agreement.

10. Disclosure to Representatives. Recipient shall be responsible for ensuring that its or its affiliates' Representatives who are given access, either directly or indirectly, to the Confidential Information are aware of the terms of this Agreement and agree to be bound by those terms. In any event, Recipient shall be liable under this Agreement for any disclosure of Confidential Information by its or its affiliates Representatives in violation of the terms of this Agreement.

11. Counterparts. This Agreement may be executed in two (2) or more counterparts, each of which so executed shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument. PNM and Recipient may retain a duplicate copy (e.g., electronic image, photocopy, facsimile) of this Agreement, which shall be considered an equivalent to this original.

12. Governing Law. This Agreement shall be governed in all respects by the laws of the State of New Mexico, without reference to the conflict of laws provisions thereof. Any action at law or in equity or judicial proceedings instituted by a Party for the enforcement of this Agreement shall be instituted only in the state courts of the State of New Mexico or the federal courts sitting within the State of New Mexico.

13. Notices. Any notice or other communications required or permitted to be given pursuant to this Agreement shall be confirmed in writing and shall be deemed properly given when hand delivered, sent by overnight mail service, mailed certified mail, return receipt requested, or transmitted by electronic mail with date and sending Party identified to the following addresses:

For PNM: Public Service Company of New Mexico
Attn: Nicholas Phillips
414 Silver Avenue SW
Albuquerque, NM 87102
Telephone: 505-241-2676
Email: Nicholas.Phillips@pnm.com

For Recipient: [Company Name]_____
Name and Title: _____
Address: _____
_____
Telephone: _____
Email: _____

14. No Assignment. This Agreement may not be assigned by either Party unless the other Party's prior written consent is obtained; however, upon written notice, either Party may assign this Agreement (including the right to enforce its terms) to a parent, affiliate or subsidiary at its sole discretion without the other Party's consent.

15. Non-Waiver. No waiver of any provision of this Agreement shall be deemed to be nor shall constitute a waiver of any other provision whether or not similar, nor shall any waiver constitute a continuing waiver. No waiver shall be binding unless executed in writing by the Party making the waiver.

16. Waiver of Trial by Jury. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HEREBY KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES ALL RIGHTS TO A TRIAL BY JURY IN ANY LEGAL ACTION TO ENFORCE OR INTERPRET THE PROVISIONS OF THIS AGREEMENT.

17. Publicity. Vendor shall not make any public disclosures regarding PNM or the subject matter hereof, including, without limitation, any advertisements, publications or documents, or by representations of partnerships, agreements or positions contained within the resulting modeling runs or reports, or any presentation or other disclosures concerning the material therein, without the prior written approval of PNM.

18. Further Conditions. PNM's performance of modeling as contemplated herein does not constitute, and shall not be construed as, its agreement with the results of the modeling runs nor shall the modeling results supersede the results of any related analyses performed by PNM.

19. Entire Agreement; Amendments. This Agreement represents the entire understanding between the Parties with respect to the subject matter hereof and supersedes all prior communications, agreements and understandings related thereto. The provisions of this Agreement may not be modified,

amended or waived, except by a written instrument duly executed by both Parties.

[Signature page(s) follow]

IN WITNESS WHEREOF, the Parties caused their duly authorized representatives to execute this Agreement to be effective as of the Effective Date.

Public Service Company of New Mexico

By: _____

Name:

Title:

[Recipient]

By: _____ Name:

_____ Title:

_____

5 Signature Page to Confidentiality Agreement between PNM and Recipient

Categorizing Questions and Comments

1. Scenarios
2. Modeling run prioritization criteria and run requests
3. Analysis Framework
4. Inputs and Assumptions
5. Modeling Rules/Constraints
6. Outputs

Scenarios (could be basis for additional modeling runs)

- Decarbonize the grid much sooner than 2040. (A. Christodoulou)
- Model (from a clean slate) a PNM fully decarbonized grid with wind, solar, a 1500 MW/70-hour duration PSH, minimal transmission incremental build, and separate/distinct fast-response grid stability resources such as BESS. From any sort of “end case” optimized model (such as the one suggested immediately above), then determine the interim steps that get you to the desired end state in an efficient manner from a cost, reliability, and emissions standpoint. (T. Conroy)

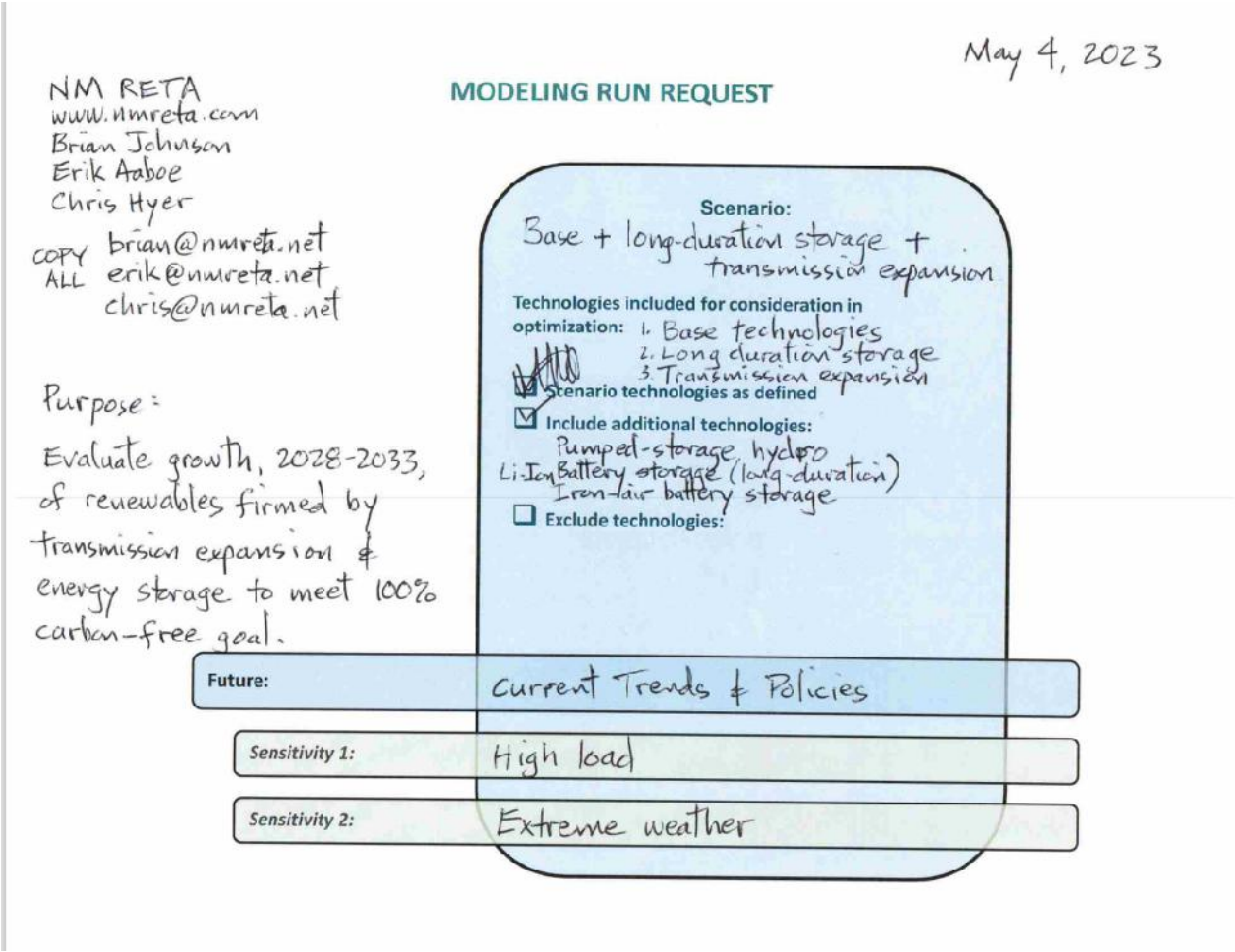
Modeling Run Prioritization Criteria and Run Requests

Candidate Prioritization Criteria (anonymous input)

1) Rank as determined by vote of modeling working group members
2) Alignment with Statement of Need
3) Delineation from existing scenarios
4) Runs that impact short term (within 10-year horizon) implementation rather than the long term interpretation (currently doing?)...This contradicts input from others that suggests at least one 20-year horizon scenario and resiliency analysis be conducted.

Run Requests

- We would like to see a run with base technologies, current policy trends & high penetration of EVs and electrification of space heating, given the incentives from Congress that we are going to be administering and adding to our own state programs. (J. Waite)
- Scenario with significant increase in demand response (several stakeholders).
- My early research results point to higher costs for wind generation resources due to likely long term wind "droughts" not anticipated in PNM's models. That motivates a desire for running scenarios or sensitivities with alternate treatment of wind resources either through their ELCC input to capacity expansion modeling or through the extreme weather data used as inputs for both Capacity Expansion and PCM models. (G. Wilke)



May 4, 2023

NM RETA
www.nmreta.com
Brian Johnson
Erik Aaboe
Chris Hyer

COPY ALL
brian@nmreta.net
erik@nmreta.net
chris@nmreta.net

MODELING RUN REQUEST

Purpose:

Evaluate growth, 2028-2033, of renewables firmed by transmission expansion & energy storage to meet 100% carbon-free goal.

Scenario:
Base + long-duration storage + transmission expansion

Technologies included for consideration in optimization:
1. Base technologies
2. Long duration storage
3. Transmission expansion

☑ Scenario technologies as defined
☑ Include additional technologies:
Pumped-storage hydro
Li-Ion Battery storage (long-duration)
Iron-air battery storage
☐ Exclude technologies:

Future: Current Trends & Policies
Sensitivity 1: High load
Sensitivity 2: Extreme weather

Analysis Framework

- Need a process for forecasting complete replacement of the grid vs forecasting the implementation of incremental dispatchable resources onto an existing system. (T. Conroy)
- Consideration of assets that are owned by 3rd parties instead of utility-owned. (T. Conroy)

Inputs and Assumptions



- Review ELCCs for solar, wind, storage and combinations (C. Mitchell) and reflect synergies among them (C. Leger). Suggested reference on this offered by E. Aaboe: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf
- Be explicit regarding Demand Response and Energy Efficiency , and consider a model run with significant increases in both (several stakeholders)
- Use of LCOE for resource costs (instead of what? Capital costs?) (C. Mitchell)
- Review reliability of fossil resources as in the past, they were modeled as more reliable than warranted. (C. Leger)
- Market availability and transmission interconnections must be adequately considered. (C. Leger)

Questions and Comments

From J. Waite, EMNRD, 5/8/23

- How is long-duration v. short duration storage modelled? For example, we are trying to understand if there costs associated with deferring long-duration storage now and having the short-duration storage (batteries) left as stranded assets later?
- What types of energy security events or impacts are modeled and cost out with LOLE? Are any cascading impacts to human health and economic function embedded in the model? Does the modeling include potential for sabotage (physical attacks) or cyberattacks?

From C. Beadles, WRA, 5/13/2023

- Should other types of gas plants should be considered in the modeling and not just aeroderivative. I'm wondering whether the emissions and operational performance of existing gas could be improved cost-effectively to avoid new gas that should be depreciated faster to avoid or reduce stranded investment risk in the future. Response captured by A. Gould based on 5/11/2023 meeting… Aeroderivative is used as a generic asset in the IRP as it is the combustion technology most likely to meet the portfolio needs; such as size, start time, ramp time, etc. When an RFP is issued for actual resources, technology other that aeroderivative can be submitted and will be considered, at which point (in CCN/PPA filings) intervenors can question issues such as potential stranded investment risk of new investment vs. existing generation assets.

From T. Conroy, 5/8/23, regarding seasonal duration storage

1. For all seasonal duration energy storage technologies except PSH, there are technology, cost, and commercial risks which must be considered and projected.
2. PSH has permitting timeline, construction timeline, and construction cost risks, but as a 100-year-old technology does not have meaningful technology or commercial risks.
3. Approx. 50% of PSH project capital costs will be spent locally, as compared to the approx. 5% to 10% spent locally on solar, wind, and BESS technology projects. It is unclear if these local construction jobs impact should be included in any analysis. For the Carrizo PSH project at $3.6 billion capital in 2020$, the local construction spending is estimated at $1.8 billion. Construction jobs are estimated at 673 direct/2,196 total jobs for a 5-year period.
4. Note that PSH projects are expected to remain in service for more than 100 years. The first PSH project in the U.S. (Rocky River Plant) was built 96 years ago and remains in service at 29MW nameplate.
5. Note that the Carrizo project is located on Navajo lands and is therefore expected to qualify for a 50% ITC remuneration level.
6. There is a great deal of uncertainty in projecting PSH construction/capital expenses since no plants have been built in the U.S. for decades. The attached whitepaper which Kinetic power wrote to NREL to inform their future technologies and costs projections defines the cost estimation process used for the Carrizo project. We feel that our empirical based, adjusted to 2020$ approach is the most accurate possible approach to PSH cost estimations today.
7. PNM IRP timeline and interest rate projections:
    a. The Carrizo project license (pre-construction) timeline is expected to be 3 to 4 years.
    b. The (subsequent) construction timeline to COD is expected to be 4 to 5 years.

   Construction and technology inflation and interest rate assumptions will presumably be crucial to make consistent for PNM asset choices to be deployed in future years.

From T. Conroy, 5/19/2023

1. Is the PNM 8760 hourly load data (for 2022 or 2021) now classified as "PNM confidential"?
2. I'm not precisely sure what "respondents to PNM RFPs" means, but I will presume that Kinetic Power falls into this category. Does it mean currently open RFP's, past RFP's, future expected RFP's, does it include RFI's, etc.

From K. Gould, NM AREA, 5/8/23

- Has Gridworks facilitated IRPs for other utilities? I am curious because maybe your expertise can help in navigating how the modeling inputs should be presented for a transparent review by stakeholders. It is my understanding that in other jurisdictions the third party modelers (Ascend and Astrape in this case) present a table of sorts an the outset, stating all the assumptions they have used and what the sensitives in the models are aka which assumptions really drive the modeling. It would be extremely helpful in deciding what to ask PNM to model to have these assumptions at the outset. For starters, can we get:
  (1) What are the key assumptions PNM has changed in this IRP from 2020?
  (2) What are the cost assumptions PNM is using for all the technologies and how did it derive these cost assumptions? MLT REFERRED HER TO https://gridworks.org/wp-content/uploads/2023/05/2023.05.12-Candidate-resources.pdf.
  (3) Are there any artificial MW limits to any of the technologies or MW grouping, like wind has to be added in 400MW bundles ect?
  (4)What is the import limit during the highest need hours?
  (5)What is PNM modeling to be the high need hours /months or its coincident peak? Is PNM using 3S1W or modified 3S1W or something else?
  (6) How is PNM treating the expiration of Reeves and Valencia in the models?
  (7) What is PNM modeling for the forced outage rates of PNM's existing plants and how did it derive those figures?
  (8) How is PNM modeling interruptible load?
  (9) How is PNM modeling the ETA carbon limit - is it assuming this number is an annual number?
  (10) How many MW of battery/ solar/ wind is PNM modeling in its base case?
  (11)What is PNM's current mix of resources that has been approved by the Commission?
  (12) Has PNM modeled any coordination with regional utilities to pool planning reserves?
  (12) Can PNM model a possible scenario of PNM joining an RTO with either CalISO or SPP?
  (13) Can PNM run models with averages of actual costs from its RFPs?

NM AREA is not likely going to run its own models this year but would still like to know how long it would take for PNM to set up a VM or to give us access to the models with all the input information. MLT REPLIED THAT VM WILL NOT BE AVAILABLE DURING THIS IRP CYCLE.

From M. Ballantine (5/11/2023)

- Curious about LOLE (%) vs cost of resource options.

From H. Gopalakrishnan (5/11/2023)

- Why not run 8760 MIP in Capacity Expansion (i.e.: fitted chronology) with either 1 year steps with no overlap or 2 year steps with 1 year overlap. This helps avoid the uncertainties associated with ELCC methodology.

From R. Wilson (5/11/2023)

- There are additional tax credits that PNM might take advantage of, including those relating to % of domestic content and projects cited in Energy Communities. Will those be modeled for different technologies?" (R. Wilson)

From G. Wilke (5/11/2023)

- How would the capacity expansion model incorporate feedback from PCM regarding likely long-term outages of Li-Ion units?
- Regarding purchase of hydrogen does the carbon intensity law limit PNM to 100% green hydrogen while restricted to 0 carbon intensity.

From C. Ho (5/11/23)

- During the 5/11 meeting, Nick mentioned the possibility of using EUE in addition to LOLE in the future. How will you weight or combine multiple reliability metrics to form the basis for your decisions? Also, it would be helpful to present a definition and/or illustration of these reliability metrics (e.g., LOLE, LOLH, LOLP, EUE, NEUE) and how they will be used.
- I would like to see a table of input parameters and their uncertainty distributions. In other words, what parameters are you treating stochastically (probabilistic) vs. discretely (sensitivity)? In particular, I would like to see more information about uncertainties in generation (wind, solar), storage, and load."
- Extreme weather considerations (C. Ho, E. Roesler, T. Nguyen, and J. Ellison)
  Conclusions from Sandia National Labs (contained in SANDIA REPORT SAND2022-0583 Printed January 2022). “Results for the extreme climate-change scenario show that the projected wind power may decrease by ~13% due to projected decreases in wind speed. Projected solar power may decrease by ~4% due to decreases in irradiance and increases in temperature in NM. Uncertainty in these climate-induced changes in wind and solar resources was accommodated in probabilistic models assuming uniform distributions in the annual reductions in solar and wind resources. Uncertainty in battery storage performance was also evaluated based on increased temperature, capacity fade, and degradation in round-trip efficiency. The hourly energy balance was determined throughout the year given uncertainties in the renewable energy resources and energy storage. The loss of load expectation (LOLE) was evaluated for the 2040 No New Combustion portfolio and found to increase from 0 days/year to a median value of ~2 days/year due to potential reductions in renewable energy resources and battery storage performance and capacity. A rank-regression analyses revealed that battery round-trip efficiency was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. An increase in battery storage capacity to ~25,000 – 30,000 MWh from a baseline value of ~14,000 MWh was required to reduce the median value of LOLE to ~0.2 days/year with consideration of potential climate impacts and battery degradation.”

From C. Mitchell and E. Rilkoff (5/19/2023)

To: Margie Tatro and Amanda Gorman, Gridworks
From: Ed Rilkoff, PRC Utility Division Director, and Cynthia Mitchell, PRC Staff Consultant
Re: Statement of Need and Modeling and Scenario Analyses Request for Information and Data
Date: May 19, 2023

Please see the following information request regarding the Statement of Need (SoN), and Modeling and Scenario Analysis discussed in the May 18th PNM Gridworks Stakeholder Meeting. This information and data necessary to work towards a consensus SoN, and to offer informed recommendations on modeling and scenario analyses. Given the May 26th due date for Model Run Requests and suggested prioritization criteria, PRC Staff requests that PNM respond as soon as possible.

1. Could PNM provide its preliminary or draft 2023 Loads and Resources Table per Outline 3.c? See PNM 2020 IRP Table 22 "Existing resource dependable capacity & incremental resource needs (Current Trends & Policy future.

2. For the Peak Demand in (1), could PNM please clarify whether this is this a single hour coincident peak?.

a. Could PNM please provide the peak demand load duration curve for the first and last year of the forecast period.

3. For solar, wind, and storage in (1), could PNM please provide a listing of the individual projects, noting additions and retirements.

4. For storage, if not already provided in (3), could PNM please indicate the storage application or use, for instance, is the storage paired with solar or wind or other applications.

5. Could PNM please provide the details regarding DR included in (1), and how this is different from its 2020 IRP.

6. Could PNM please provide in preliminary or draft form a table showing first year (and last year, if available) Installed and Effective Capacity by Resource Types, similar to PNM's 2020 Table 31.

7. For the May 11th handout outlining the 3 Phases of scenarios and modeling, could PNM please provide the following information and data:

a. The preliminary or draft detailed summary of the results of the Phase 1 Base Technology Only Scenario similar to PNM's 2020 IRP Appendix J.

b. For each of other 14 Phase 1Scenarios, the timing and amount of the additional technology added to the Base Technology Only Scenario.

c. For the 14 Phase 2 Scenarios, the timing and amount of the additional technologies added to the Base Technology Only Scenario.

8. For the May 11th handout on the capital costs, $/kW ($2022), of renewable, thermal, and storage, could PNM please provide the LCOE for each resource.

From C. Ho (5/23/2023)

PNM IRP Modeling Input Parameters, suggested summary

Sample inputs and tables

Climate/weather/environment

Category	Input parameter	Value	Notes
Weather	Irradiance	Fixed vs. stochastic	Distribution type or scenario
Weather	Wind	Fixed vs. stochastic	Distribution type or scenario
Wildfires	Smoke impact on irradiance	Fixed vs. stochastic	Distribution type or scenario (e.g., temporal to accommodate wildfire season)
Drought	Water availability	?	Impact on pumped hydro?
Extreme heat	Temperature	Fixed vs. stochastic vs. temporal	Impact on load (e.g., air conditioning)

Supply/Resources (relative to installed nameplate capacity)

Category	Input parameter	Value	Notes
Weather	Irradiance	Fixed vs. stochastic	Distribution type or scenario
Weather	Wind	Fixed vs. stochastic	Distribution type or scenario
Solar	Capacity factor	Fixed vs. stochastic	Distribution type or scenario
Solar	Degradation	Fixed vs. stochastic	Distribution type or scenario
Wind	Capacity factor	Fixed vs. stochastic	Distribution type or scenario
Wind	Degradation	Fixed vs. stochastic	Distribution type or scenario
Resource X	Etc.	Etc.	Etc.
Resource Y	Etc.	Etc.	Etc.
Other generation	Etc.	Etc.	Etc.

resources?			
Storage	Battery round-trip efficiency	Fixed vs. stochastic	Distribution type or scenario
Storage	Battery capacity fade	Fixed vs. stochastic	Distribution type or scenario
Storage	Other storage technologies	?	?

Demand

Category	Input parameter	Value	Notes
Demand	Load	Fixed vs. stochastic vs. temporal	Distribution type or scenario; accommodation of increased electrification from heat pumps, EVs
Demand	Demand response	Fixed vs. stochastic	Distribution type or scenario
Demand	Efficiency	Fixed vs. stochastic	Distribution type or scenario

From K. Raman and R. Wilson, Form Energy (5/25/2023)

Scenario Requests

- Scenario Request: Model a “no combustion” scenario which retires all existing combustion resources by 2040 to meet PNM’s decarbonization goals
    - Candidate Technologies:
        - Technologies Included: Solar, Wind, Li-ion storage, Long duration storage, wind expansion, geothermal
        - Technologies Excluded: Retirement of all existing natural gas combined cycle and combustion turbine resources by 2040. Retrofit of combustion resources with green hydrogen or CCS is excluded from selection.
    - Future: Current Trends and Policy
    - Sensitivities:
        - Evaluate two different retirement schedules for existing combustion resources:
            - Require combustion plants to retire at the end of their depreciation schedule
            - Require model to retire all combustion plants by 2040, but allow for endogenous retirement of combustion plants in preceding years based on economics
    - Rationale for scenario request:

- IRP should consider a future in which all fossil fuel combustion turbines are retired to meet PNM's 2040 goal of 100% emissions-free energy
  - Technologies such as green hydrogen and carbon capture have yet to be deployed at commercial scale, which results in a high degree of cost uncertainty
  - In particular, green hydrogen also requires buildout of infrastructure for producing, storing, and transporting hydrogen fuel, which may not exist in 2040
- Combustion resources of all types have air quality impacts on local communities
  - Criteria pollutants, such as NOx, are generated by combustion resources regardless of whether they are operated using natural gas or green hydrogen
  - These criteria pollutants can be linked to occurrence of chronic respiratory illness in local communities

Criteria for Scenario Prioritization:

- Expose key uncertainties in PNM's decarbonization strategy
  - Prioritized scenarios should highlight critical uncertainties that are most likely to impact PNM's ability to achieve 100% emissions-free energy by 2040
- Uncover new strategic pathways for resource procurement
  - Prioritize scenarios which may uncover alternative resource procurement pathways that are directionally distinct from PNM's existing IRP
  - Deprioritize scenarios which are likely to result in marginal modifications to the existing IRP
- Be completed in a reasonable amount of time with reasonable effort
  - Certain scenarios may require an inordinate amount of time to be set up and/or run through the models. Time versus value should be considered when prioritizing scenarios.

From M. Ballantine and G. Wilke (5/26/2023)

Glen,

I would not worry too much about gaining access to PNMs data, as understanding them in even a week would be a herculean task (I presume, as I myself have not studied their datasets).

Regarding the timeline, I assume that it is non-negotiable at this point, and so would spend time formulating a general modeling request rather than a specific one. What you write in your bullets 1. and 2. is probably plenty sufficient to make a request to PNM, something along the lines of "perform sensitivity studies on resource lifetimes and capital costs of exotic resources". I would enumerate the exotic resources of interest and specify the range (of lifetimes and capital costs) that you would like to see, as this will ensure that the modeling outputs address your concerns.

Best Regards,

Marissa

From: Glenn Wikle <glennwikle@gmail.com>
Sent: Friday, May 26, 2023 8:34 AM
To: Ballantine, Marissa D <mdballa@sandia.gov>; Newlun, Cody Jack <cjnewlu@sandia.gov>; cliffort_ho@heinrich.senate.gov
Subject: [EXTERNAL] PNM IRP modeling feedback timeline too tight

As of this moment I do not have access to the public modeling data so do not understand the inputs well enough to formulate my requests for modeling runs by COB today.

Even if I did get access to the data today *and* could actually make sense of the data set *in the few hours available*, I don't know if the public subset of the data is sufficient to understand the full breadth of the inputs being used.

In general, this process is being rushed so much that I wonder how the most involved stakeholders can keep up with it and provide meaningful feedback. I wonder if it is time to officially ask the PRC for more time. It was their late rulemaking that put us in this situation.

I want to speak to you about my main concerns, which are about economic modeling of the more "exotic" resource types based upon what I have seen in the previous IRPs:

1. It looked like the resource lifetimes were too short (by possibly as much as 50 years) for some of the more exotic resources. I believe this skews cost effective price modeling and might skew it enough to lead to incorrect decisions. Would this be dealt with as a sensitivity study? I think NREL has published the price variances so we could use those for such a study? (Access to the Siemens price data would help me understand this better.)

2. Some resource types have very large capital price variance and I don't think PNM ran sensitivity studies to take this into account. I don't know if the Siemens price db takes this into account which is why I want to look at it before I formulate a specific request.

More clarification from G. Wilke (5/26/2023)

Here I am filling in the requested details and adding more since I found another concern while reviewing the "resource catalog" from PNM. Do I need to forward this to PNM or will you folks do that?

The "exotic" resources with high cost variance are Geothermal, PSH, and compressed air. All have large variance which depends upon the geology and terrain where they are sited. There is, in fact, one example of the huge cost variance (for geothermal) in PNM's slides. I'd like to see a sensitivity study which shows us how sensitive PNM's results are to this variance. Lacking specific input from NREL I'll suggest a few points between 30% less than Siemens' number and 30% over their number

Plant lifetimes were not given in PNM's input tables. I would like to see a run with maximum lifetimes for these three resource types. For PSH and compressed I believe 100 years is reasonable. For Geothermal I don't really know but could we run with 50 and 75 years? The main idea is to see what happens if you

don't use the standard 30-year lifetime for these types of resources.

My new concern is that PNM is using a 10-hour PSH resource. I doubt this scales up linearly (which is how the capacity expansion model would scale it). Due to economy of scale, the cost per MWh decreases as capacity of the facility increases. A proxy for understanding this would be the lower end of the cost sensitivity study requested in my first paragraph, i.e. one of the reasons for high cost variance is economy of scale.

From K. Gould (5/26/2023)

Hi all:

NM AREA is interested in the follow modeling runs:

1. A model run that models correlated outages of natural gas fired plants

2. A model run that extends Valencia PPA until 2040 and no new natural gas (looking for the costs and reliability of this scenario)

3. A model run that extends both Valencia and Reeves until 2040 an no new natural gas (looking for the costs and reliability of this scenario)

4. A model run that models PNM participation in an RTO in the next 5 to 10 years

I know these are very broad requests, but if the rest of the group is interested in the outcomes of these runs NM AREA is happy to work with the group and PNM to come up with some parameters for these runs. Thank you.

I would also like to see the base case modeled with 4 Corners. It is odd the PNM did not model 4 Corners when the NMPRC denied the abandonment. This seems like a hole in the IRP. NM AREA does not have an opinion as to whether that decision was appropriate but it was the decision of the NMPRC and it should be modeled as a system resource until the PRC approves abandonment.

From C. Ho (5/26/2023)

I would like to see the following modeling scenario:

- Base-case technologies with inclusion of extreme climate impacts by 2040 (i.e., lower irradiance and lower wind resources).
    - Potential climate impacts on solar and wind resources can reference SAND2022-0583
        - This run should also consider uncertainties in battery performance (RTE and capacity fade)

Working Group Purpose
Engage interested stakeholders in modeling efforts to inform Action Plan input.

Key Principles

- Allow input from a wide range of interests. Stakeholders who have expressed an interest in modeling will be considered as members of the Modeling Working Group.
- Establish a "core team" to prioritize and address the key issues and to engage with the utility modeling team.
    - Core team to prioritize model run requests using transparent criteria.
    - Core team members have knowledge of IRP related modeling activities (but do not have to be expert) and agree to represent input from a specific subset of stakeholders who have an interest in modeling efforts.
- Keep all interested stakeholders informed.
- Gridworks will organize stakeholder comments and questions and will work with the core team and utility modeling team to document responses to questions.
- Provide opportunity for stakeholders who have done their own analysis to share their observations with all stakeholders.
    - Note that the utility is not obligated to accept the findings.
    - Note also that such findings could inform future modeling frameworks and planning processes.

Modeling Activities and Data Sharing

1) PNM will perform modeling of stakeholder modeling runs as prioritized by the modeling core team.
2) Virtual machine access to PNM's modeling platform and software will not be available during this IRP cycle.
3) Stakeholders wishing to run EnCompass or SERVM models are responsible for having expertise to run the programs and acquiring the appropriate training.
4) A public-facing data set of modeling input information will be made available through VENUE. Target release date of May 24, 2023. A public-facing data set of model output information will also be available over the course of the modeling activities.
5) Stakeholders who request PNM confidential modeling information (both input and output data) who are not engaged with PNM RFIs or RFPs, are not participants in the Eergy Imbalance Market, and have signed a confidentiality agreement, will be provided access to this information through VENUE.
6) If requested, licenses for EnCompass and SERVM software will be provided by PNM to stakeholders who have obtained approved licensing agreements from the software vendor(s).

Categorizing Questions and Comments
Stakeholder questions and comments will be publicly available and organized as follows:

1. Scenarios

2. Modeling run prioritization criteria and run requests
3. Analysis Framework
4. Inputs and Assumptions
5. Modeling Rules/Constraints
6. Outputs

Proposed Engagement Plan and Timeline (BOLD DATES ARE SCHEDULED STAKEHOLDER MEETINGS)

May 4: Stakeholders interested in modeling identify themselves to Gridworks

May 11: PNM modeling presentations delivered and recorded

May 15: Proposed modeling engagement plan circulated to working group for feedback.

May 18: Revised modeling engagement plan presented to all stakeholders during stakeholder meeting. Modeling core team (of 5-8 people) formed. NDA distributed (and due back to IRP@pnm.com with copy to mtatro@gridworks.org and nicholas.phillips@pnm.com by June 15).

May 19: Comments on modeling engagement plan (preferably in redline format) due to mtatro@gridworks.org by 5 PM MDT.

May 19 - June 15: Stakeholders may request access to either public facing or confidential modeling information via password protected VENUE platform. (Access to proprietary info - both input and output data - requires a signed NDA.) Stakeholders with an approved license agreement for EnCompass and or SERVM may request software licenses, which will be paid for by PNM.

May 26: Model Run Requests and suggested prioritization criteria due to mtatro@gridworks.org who organizes the information for the Modeling Core Team.

June 1: Model Run prioritization criteria finalized during stakeholder meeting (by dot-voting)

June 8: Modeling core team applies criteria, combines requests (if appropriate), and develops prioritized list of model runs. Recommendation presented at June 15 meeting.

Note: as of 5/7/23, two model run requests (included in See ANNEX 3), have been submitted to the facilitators and will be considered by the modeling core team.

Note: as of 5/7/23, four model run prioritization criteria have been received:

1) Rank as determined by vote of modeling working group members
2) Alignment with Statement of Need

3) Delineation from existing scenarios
4) Runs that impact short term (within 10-year horizon) implementation rather than the long term interpretation (currently doing?)...This contradicts input from others that suggests at least one 20-year horizon scenario and resiliency analysis be conducted.

June 15: Latest date for model information request and signed NDA due back to IRP@pnm.com with copy to mtatro@gridworks.org and nicholas.phillips@pnm.com

June 15:

- PNM shares preliminary results of their EnCompass (scenario) modeling (Phase 1 & 2) and PNM short list of most cost effective portfolios (MCEPs) which will require additional analysis alongside stakeholder scenarios to finalize.
- Core Team reports prioritized (additional) model run requests to all stakeholders. PNM provides feedback regarding feasibility of requested runs. Decision on how to proceed.

June 15 – July 13:

- PNM – additional EnCompass (scenario) modeling of prioritized requests; and SERVM modeling of PNM MCEP shortlisted scenarios
- Stakeholders – independent analyses

June 29: full day, in person workshop discussing modeling results so far and path forward. Modeling working group members with their own analyses will be given the opportunity to present their observations. Discussion of whether additional SERVM runs are necessary.

NOTE: specific activities after June 29 may be adjusted to support development of Action Plan input.

July 13: PNM presents results of prioritized stakeholder requested modeling runs (EnCompass). Decision on need for additional SERVM runs. Note that depending on the number of runs requested and the complexity of analysis, this might have to shift to late July or early August.

August 17: Review PNM results of additional stakeholder requested modeling runs. Decide on need for additional SERVM runs. Last opportunity for stakeholders to share results of independent analyses.

Sept. 14: Review results of additional SERVM runs conducted, if requested by the modeling core team. Review results of resiliency study on single MCEP. Develop action plan input and check consistency with SoN.

Oct. 19: Determine level of consensus regarding action plan, using results of modeling.

ANNEX 1 - Stakeholders with Modeling Interests
The modeling working group consists of any stakeholder who has expressed an interest in modeling activities. A Modeling Core Team is a subset of the working group.

Proposed candidates for Modeling Core Team:

- Research community representative - Marissa Ballantine/Cody Newlun, Sandia National Labs.
- Environmental advocates representative - Aaron Gould, WRA
- New Mexico State agencies representative - Ed Rilkoff/Cynthia Mitchell, NM PRC Utilities Division
- Consumer interests - Keven Gedko, NMAG
- NM Large business interests - Kelly Gould, NM AREA
- Renewable Energy developers/providers - Kailash Raman/Rachel Wilson, Form Energy and Chris Leger/Mike Goggin, Interwest Energy Alliance
- Energy Storage (including long duration storage) developers/providers - Alondra Regalado/Sergio Duenas, Western Energy Storage Taskforce of the CA Energy Storage Alliance
- Advisor - Cliff Ho

Decision on composition of modeling core team will be made by Gridworks in consultation with PNM.

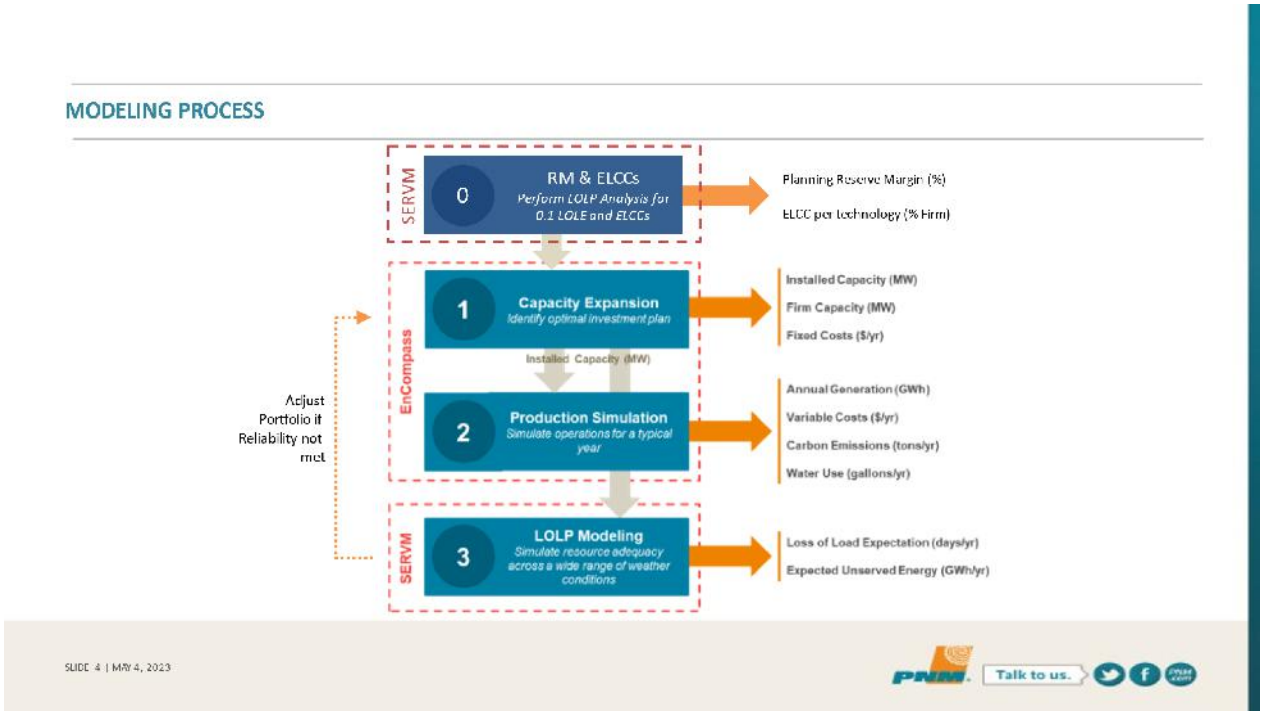
Note: one stakeholder raised the issue of possible conflict of interest by potential RFP participants with regards to representation on the Modeling Core Team. The stakeholder recommended the core team be composed of trade associations, rather than individual companies. This concern will be documented in Gridworks' report to the PRC at the end of the stakeholder process.

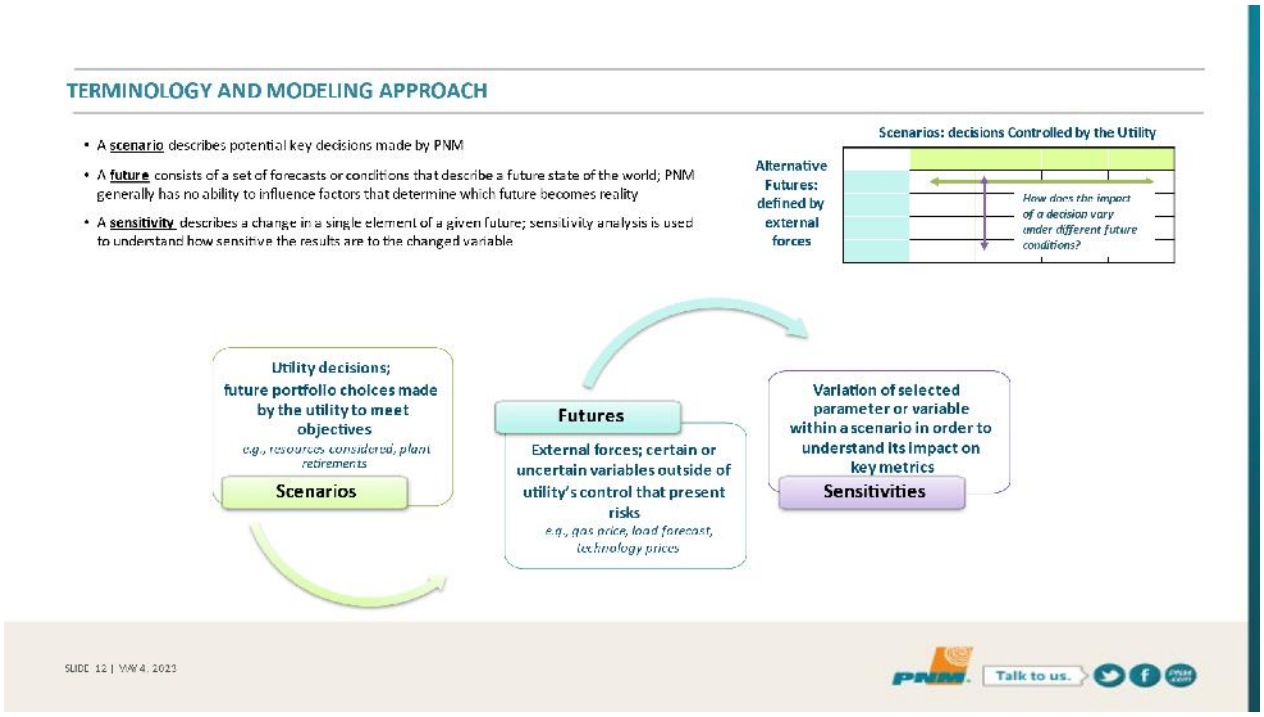
Modeling Core Team Resources shown in teal highlight.

Name	Organization	May 4 Modeling Break Out Attendee	Unable to attend May 4
Nitin Luhar	Mitsubishi Power	X	
Thomas Conroy	Kinetic Power	X	
Olga Lavrova	NMSU	X	
Glenn Wilke	NMSU	X	
Fengyu Wang	NMSU		X
Orland Whitney	NMSU	X	
Aaron Gould	WRA	X	
Cynthia Mitchell	Community Member	X	
Hector Dorbecker	PNM	X	
Shane Guiterrez	PNM	X	

Name	Organization	May 4 Modeling Break Out Attendee	Unable to attend May 4
Nitin Luhar	Mitsubishi Power	X	
Thomas Conroy	Kinetic Power	X	
Olga Lavrova	NMSU	X	
Glenn Wilke	NMSU	X	
Fengyu Wang	NMSU		X
Orland Whitney	NMSU	X	
Sarah Baxley	PNM	X	
Nick Phillips	PNM		X
Nick Wintermantel	Astrape Consulting	X	
Kevin Cox	CDG Engineers	X	
Jerry Montaño	Pueblo of Sandia	X	
Cliff Ho	Sen. Heinrich's Office	X	
Ed Rilkoff	NM PRC	X	
Bamadou Ouattara	NM PRC	X	
Eli LaSalle	NM PRC		X
Bruno Carrara	Community member	X	
Marissa Ballantine	Sandia Natl Labs	X	
Kelly Gould	NM AREA	X	
Owen Smith	Meta Platforms (NM AREA?)		X
Kalish Raman	Form Energy	X	
Rachel Wilson	Form Energy		X
Brian Johnson or Erik Aaboe	NM RETA	X	
Michael Kenney	SWEEP		X
Daren Zigich	NM EMNRD		X
Leesa Nayudu	Solariant		X
William Maxwell	Community member		X
Barbara Chatterjee	Community member		X
Brian King	Kingzzzz Ranch		X
Jim DesJardins	NM REIA		X
Dugan Marieb	Pine Gate Renewables		X
Lindsay Parker	Next Era Energy		X
Ashley Sgaliardich	Next Era Energy		X
Jack Smith	Synapse on behalf of NMAG		X
Jacqueline Waite	NM EMNRD ECMD	X	
Chris Leger	Interwest Energy Alliance		X

ANNEX 2 – MODELING PROCESS

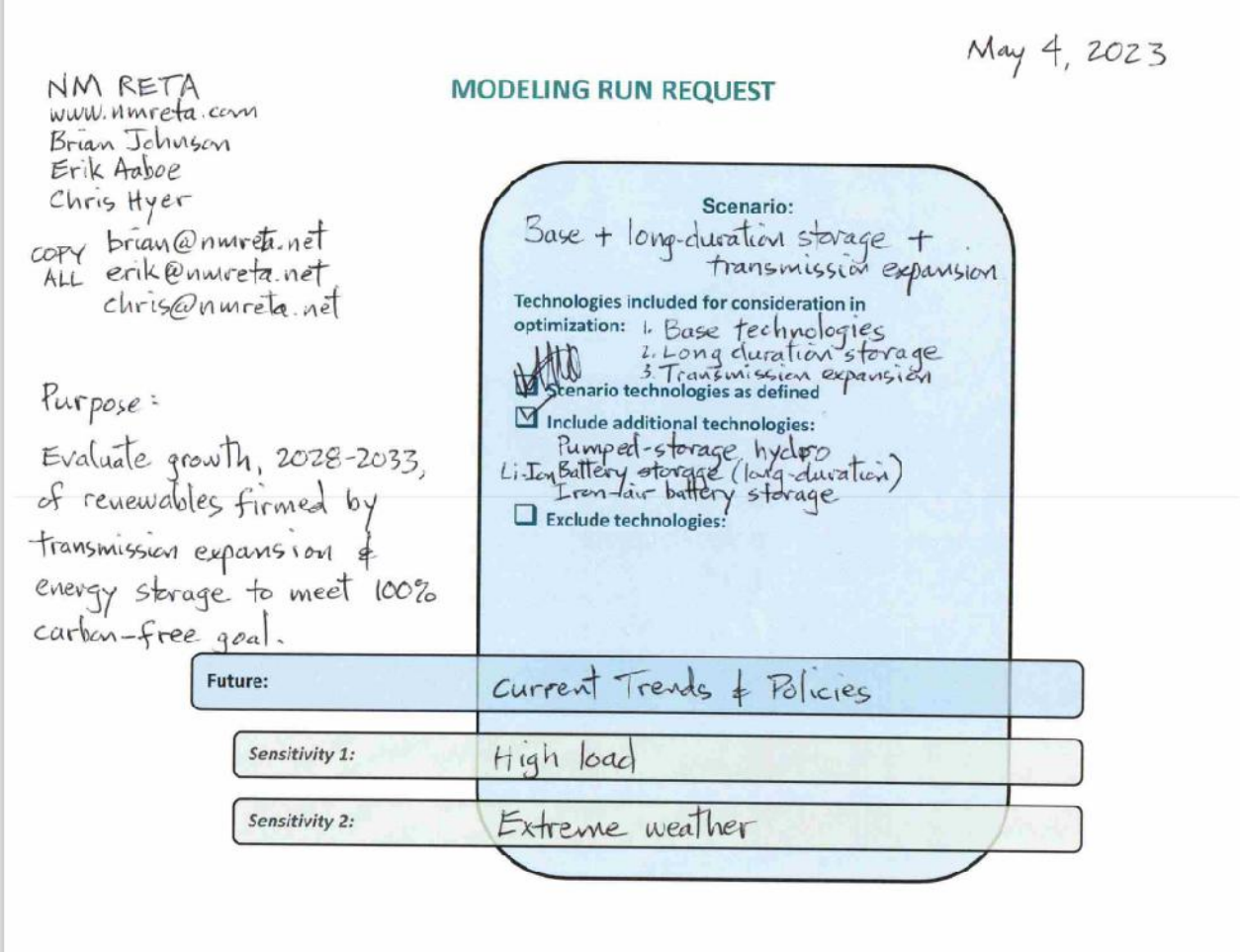





CHANGES TO INPUTS
Inputs/assumptions that can be adjusted
Fuel prices (natural gas, hydrogen)
Technology cost curves, capital costs
New candidate resources costs and/or operating parameters
Transmission cost adders
Timing of CO2-free
RPS timing and requirements
Inputs/assumptions with some flexibility for adjustment
Market prices
CO2 prices
PV or EV assumptions embedded in reference load forecast
Static inputs/assumptions (long lead time for development)
Reliability requirements (LOLE target, PRM)
ELCCs
PNM WACC
Energy Efficiency Bundles
New/different load forecasts
Study period (2023-2042)
SLIDE 16 | MAY 4, 2023
PNM
Talk to us.

ANNEX 3 - INPUTS TO DATE

Modeling Run Requests



May 4, 2023

NM RETA
www.nmreta.com
Brian Johnson
Erik Aaboe
Chris Hyer

COPY ALL brian@nmreta.net
erik@nmreta.net
chris@nmreta.net

MODELING RUN REQUEST

Purpose:

Evaluate growth, 2028-2033, of renewables firmed by transmission expansion & energy storage to meet 100% carbon-free goal.

Scenario:

Base + long-duration storage + transmission expansion

Technologies included for consideration in optimization:
1. Base technologies
2. Long duration storage
3. Transmission expansion

☑ Scenario technologies as defined

☑ Include additional technologies:
Pumped-storage hydro
Li-Ion Battery storage (long-duration)
Iron-air battery storage

☐ Exclude technologies:

Future:	Current Trends & Policies
Sensitivity 1:	High load
Sensitivity 2:	Extreme weather

We were asked to input to the "use cases to be analyzed". I am not sure precisely what that means or how to do so.

1. My "use case" request is to model (from a tabula rasa state) a PNM fully decarbonized grid with wind, solar, a 1500 MW/70-hour duration PSH, minimal transmission incremental build, and separate/distinct fast-response grid stability resources such as BESS.
2. From any sort of "end case" optimized model (such as the one suggested immediately above), then determine the interim steps that get you to the desired end state in an efficient manner from a cost, reliability, and emissions standpoint.

Thomas Conroy
Kinetic Power, LLC
M: (505) 399-0883

ADD HERE AS THEY COME IN

Integrated Resource Plan:
Statement of Need Table of Contents
Working group suggestions for Public Service New Mexico - May 15, 2023

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction
   The statement of need is that part of the IRP that describes and explains the amount and type of new resources that are necessary to reliably meet projected electricity demand in the planning horizon.
   a. Traditionally “need” expressed as the amount of capacity required to serve projected peak load
   b. “Need” must now be derived from a variety of factors including emissions reductions goals and requirements, reliability reserve requirements, replacements of existing resources, the role of flexible, demand-side and storage resources, customer renewable energy programs, availability of organized markets, the capabilities of existing transmission and distribution facilities and the impact on customers, workers and communities
   c. Informs the action plan

2. Vision and Goals
   a. Regulatory Environment and Requirements
      i. Legal requirements and standards in planning horizon
      ii. Known and expected rules
   b. Goals
      i. Reliability and Resiliency: Utility’s Obligation to Serve
         1. Minimum Reserve Requirements
         2. Reliability Standards
         3. Swift recovery from climate or cyber disruption
      ii. Public Interest and Equity
         1. Responsibilities to Ratepayers and Shareholders
            a. Affordability
            b. Availability to Underserved Communities

        c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
    2. Social and Environmental Costs
        a. Costs of Energy to Consumers
        b. Climate Change Impacts
        c. End of Life (Recycling/disposal)
    3. Consumer Education
    4. NIMBY
3. Current and Expected System Conditions
    a. Timeline
        i. Urgency (What is driving the urgency?)
    b. Load Forecast
        i. Electrification Impact
    c. Baseline System
        i. Forecasted Retirements
        ii. Transmission Constraints
        iii. Distribution System Constraints
4. Identified Decision Points and Pathways
    a. “Getting to Zero” Carbon
    b. Making “no regrets” decisions
        i. Minimizing investment risk
    c. Regional Planning and Coordination
        i. Organized Market Opportunities
        ii. Future Regional Transmission Operator
5. Resources
    a. Candidate Resources
        i. Solar
        ii. Wind
        iii. Aeroderivative gas CT
        iv. Linear generator units
        v. Lithium-ion battery
        vi. Redox-flow battery
        vii. Iron-air storage
        viii. Very-long duration/seasonal storage
        ix. Pumped-hydro storage
        x. Compressed air energy storage
        xi. Liquified air energy storage
        xii. Thermal energy storage
        xiii. Green Hydrogen
    b. Potential New Resources
        i. Adoption of new technologies
        ii. High Penetration of Distributed/Customer-owned Generation
        iii. Firming Plans
        iv. Energy efficiency and demand-response

v. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization

c. [System Needs]
d. Preferred Portfolio
    i. [results of PNM modeling]
    ii. Potential pilot projects
    iii. [PNM conclusions]

Welcome!

Stakeholder Engagement Meeting
(Meeting #4)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, June 1
9:00 – 10:30 AM Mountain Daylight Time

Materials available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose of Today's Meeting

- Our primary objective is to incorporate stakeholder input through the two work products (Statement of Need and Action Plan)
- Discussion topics include:
  - Welcome and introduction of newcomers
  - Statement of Need draft and next steps
  - Collect feedback
  - Modeling update and next steps
  - Collect feedback
  - Next meeting/workshop

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Stakeholder Engagement is Progressing to Phase 2

March – May	June – August	Sept – Nov

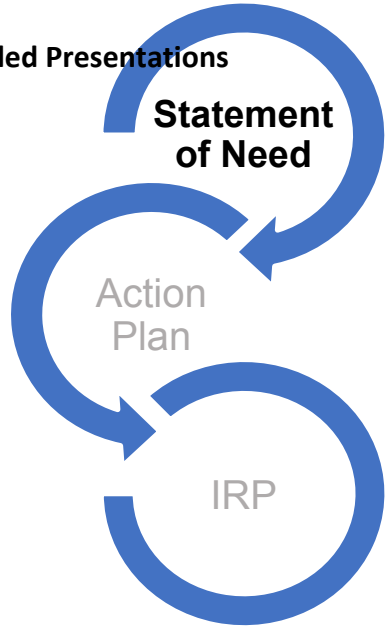
1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

- New stakeholders:
  - Please type into the chat…
  - Name, organization, one topic of interest pertaining to the IRP

Statement of Need Defined by the IRP Rule



17.7.3.8 IRPs for Electric Utilities

B. The IRP submitted to the commission by an electric utility shall contain the utility's New Mexico jurisdictional information as follows:

(1) description of existing resources, see Appendix A;
(2) current load forecast, see Appendix A;
(3) load and resources table, see Appendix A;
(4) new load and facilities arising from special service agreements, economic development projects, and affiliate transactions;
(5) identification of resource options, see Appendix A;
(6) statement of need, see 17.7.3.10 NMAC;
(7) determination of the resource portfolio, see Appendix A; and
(8) action plan, see 17.7.3.11 NMAC.

Statement of Need 17.7.3.10

- 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.
- 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.

Statement of Need Draft Update

- Review of SoN draft by volunteer group
  - presented by Michael Barrio, Advanced Energy United

- Next Steps: create “working draft” for June 15 and prepare to assess degree of consensus

Questions and Discussion

- Clarifying Question
- Is anything missing from the Statement of Need
- What concerns you?

Please offer comments, questions and suggestions the chat.

Modeling Update by Modeling Core Team

- Team captains:
  - Aaron Gould, WRA
  - Rachel Wilson, Form Energy
  - Nick Phillips, PNM
- Questions of clarification

- Next steps: prepare for modeling results sharing on June 15, and deeper dive during June 29 workshop



Questions and Discussion

- Is there input to the modeling core team you want to provide?
- What topics do you suggest the group spend time on during the June 29 workshop?

Please offer comments, questions and suggestions the chat.

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

A Look Ahead as We Prepare for Input to the Action Plan

March – May	June – August	Sept – Nov

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

NEXT DEADLINES

May 26 - Model run requests and prioritization criteria suggestions due to mtatro@gridworks.org

June 15 - Latest date to request access to modeling information (public or confidential)

SCHEDULED MEETINGS

- June 1 – Review SoN, discuss model run prioritization criteria
- June 15 – Check consensus on SoN, discuss results of PNM scenarios modeling and short list of MCEPs which will require additional analysis. Decisions on stakeholder requested additional model runs as recommended by modeling core team.
- June 29 – Full day focused on modeling results (by PNM and others) and candidate action plan suggestions. Discuss need for additional SERVM runs.
- July 13 – Results of prioritized stakeholder requested runs. Discuss and improve action plan input. Decide on additional SERVM runs, if necessary.
- Aug 17 – Review results of additional modeling runs. Refine input to action plan.

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

Update from Modeling Core Group

June 1, 2022

GRIDWORKS

agenda

- Update on modeling data
- Summary of modeling run requests received to date
- Update on questions received to date and process for posing questions to PNM
- Specific actions and next steps

Modeling data

Public data

- Uploaded Venue site, formatted as Excel tables
- Access provided to members of “Public access” group and “Confidential access” group
- Will be updated as needed based on input from core modeling group and/or PNM
- Incremental updates posted as requested by core modeling group

Confidential data

- Will be uploaded to Venue site and formatted full EnCompass input dataset(s)
- Access provided to members of “Confidential access” group
- Will be updated as needed based on input from core modeling group and/or PNM
- SERVM data not posted due to confidentiality of Non-PNM Data used to model neighbors

Modeling run requests received to date

Scenario description		Complexity/time to develop
Future CTP with high EV & High Building Electrification		Low
Future CTP with increased DR		Low/Medium
Extensions for Valencia and/or Reeves		Low*
FCPP through 2027/2031		Low
No combustion scenario post 2039 - Include: Solar, Wind, Li-ion storage, Long duration storage, wind expansion, geothermal as candidate options		Medium
No New Combustion with Thermal Storage		Medium
Accelerated Carbon Free (2030, 2035)		Medium
Complex Scenario – Transmission Expansion + Many Alternative Resources		Medium
Gas Price (High/Very High)		Low/Medium
More Extreme Weather Sensitivities		High
WRAP / RTO modeling		High
Correlated Gas Outages		High

Question for group: is ranking by complexity an adequate prioritization method?

Update on questions and proposed process for posing questions to PNM

The working group posed a question arose surrounding how to better organize the asking and answering of questions.

Proposed Idea:

If individual stakeholders have questions, they should be directed to the appropriate working group – Statement of Need or Modeling. The working groups will submit relevant questions to PNM. Gridworks will post answers on their website (or some alternative), if time allows, discuss answers at scheduled stakeholder meetings.

THIS ISSUE AND POSSIBLE SOLUTIONS ARE IN DISCUSSION. STAY TUNED FOR RESOLUTION.

For now, stakeholders are requested to send questions related to modeling to the modeling core team co-captains:

Aaron Gould aaron.gould@westernresources.org
Rachel Wilson rwilson@formenergy.com
Nick Phillips Nicholas.Phillips@pnm.com
with copy to mtatro@gridworks.org

Specific actions and Next steps

- **Actions requested of larger group**
  - Are any modeling requests missing?
  - Any clarifications or refinements of modeling requests?
  - Feedback on ranking/prioritization
  - Alignment on method for submitting questions
- **Next steps**
  - June 15: PNM will share initial modeling results from Phases 1-2, Stakeholder will submit a fully characterized list of modeling requests and prioritization approach
  - June 29 workshop: PNM will share additional modeling results (potentially including some stakeholder run requests) and any new modeling requests will be discussed/submitted.

Integrated Resource Plan:
Statement of Need Table of Contents
Working group suggestions for Public Service New Mexico - May 31, 2023

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction

   The PNM Integrated Resource Plan 2023 [IRP-2023] [provides/brings] the [best/furthest] long range path for building out the strongest, most reliable electrical power delivery system for our customers over the next 20 years as we can envision [in 2023/now]. The IRP report begins with the current status of PNM's system, and shows how available resources and technologies can bring improvements. Simultaneously we recognize that changes are occurring in most every sector of the environment in which we operate. These will require ongoing re-evaluation and modifications to the 2023 IRP plan that will be incorporated in future triennial PNM IRPs.

   Meeting our clean energy goals and preserving system reliability while providing for the growing needs of our customers in an affordable manner will require the addition of significant amounts of new generation capacity over the next twenty years. We anticipate that over the seventeen years between today and 2040, the likely amount of new installed generation capacity will total between 4,000 to 5,000 MW or more. This amount of *new* capacity is significantly greater than the amount that exists today, implying that the achievement of our goals will require continuous and significant evolution of our portfolio.

2. Vision and Goals
   a. The identification of a set of resources and a sequencing of those resource deployments that conforms to the regulations and policies of the State of New Mexico, reliably serves all customers at an equitable cost that encourages consumer electrification efforts and that is resilient in the face of physical, cyber and environmental disruptions.
   b. Regulatory Environment and Requirements

i. Legal requirements and standards in planning horizon
ii. Known and expected rules

c. Goals
i. Reliability and Resiliency: Utility's Obligation to Serve
1. Minimum Reserve Requirements
2. Reliability Standards
3. Swift recovery from climate or cyber disruption
ii. Public Interest and Equity
1. Responsibilities to Ratepayers and Shareholders
a. Affordability
b. Availability to Underserved Communities
c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
2. Social and Environmental Costs
a. Costs of Energy to Consumers
b. Climate Change Impacts
c. End of Life (Recycling/disposal)
3. Consumer Education
4. NIMBY

3. Current and Expected System Conditions
a. Timeline
i. Urgency (What is driving the urgency?)
b. Load Forecast
i. Electrification Impact
c. Baseline System
i. Forecasted Retirements
ii. Transmission Constraints
iii. Distribution System Constraints

4. Identified Decision Points and Pathways
a. "Getting to Zero" Carbon
i. Motivations
1. Regulations & Policy
a. ETA (2019)
b. EPA - evolving
2. Public Service in response to Mar 2023 IPCC report analysis - https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23

b. Making "no regrets" decisions
i. Minimizing investment risk
1. Stranded assets
2. Loss of public trust
ii. Maximizing investment opportunity
1. First to market w/ long term solutions
2. Public trust and sentiment

iii. Value of money vs future human life opportunities

c. Regional Planning and Coordination

i. Organized Market Opportunities

ii. Future Regional Transmission Operator

5. Resources

a. Candidate Resources

i. Renewable generation

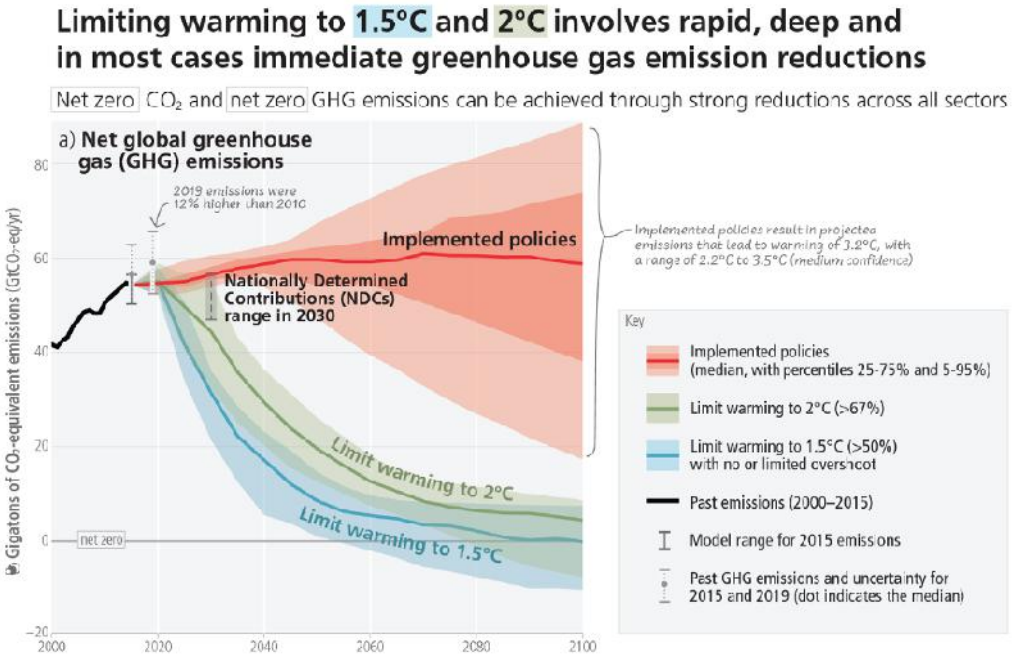
1. Solar incl Community Solar
2. Wind
3. Geothermal

ii. No new gas of any type

iii. Energy Storage

1. Short duration (up to 10 hr)

a. Lithium-ion battery etc. see below charts

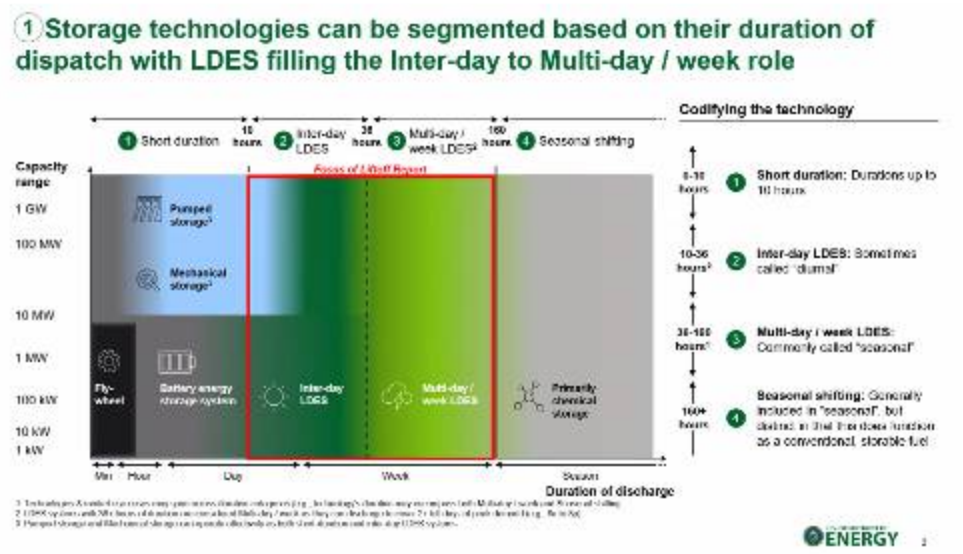


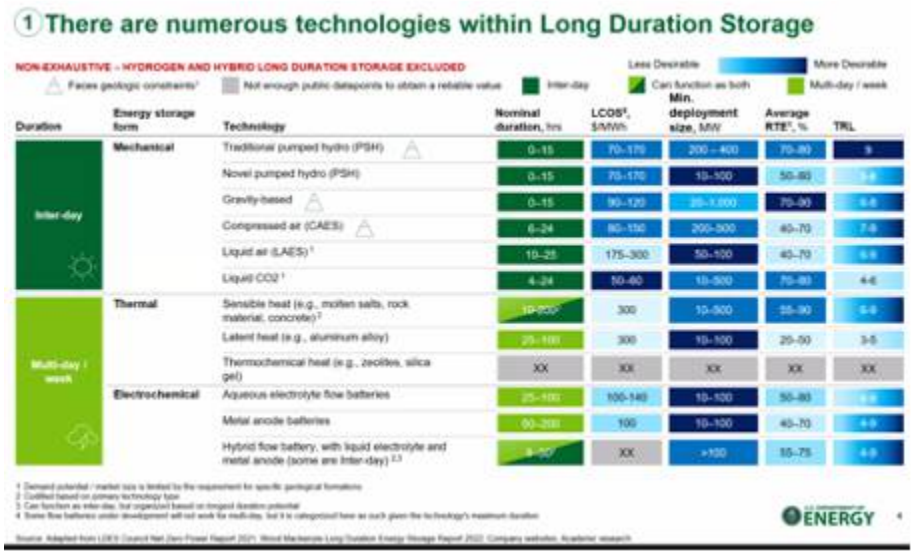
2. Inter-day & Multi-day/week Long Duration Energy Storage (LDES) - see charts below

3. Seasonal Shifting

a. Pumped-hydro storage, thermal energy storage, etc

4. Not for electric





a. Potential New Resources
    i. Adoption of new technologies
    ii. High Penetration of Distributed/Customer-owned Generation
    iii. Firming Plans
    iv. Energy efficiency and demand-response
    v. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
b. [System Needs]
c. Preferred Portfolio
    i. [results of PNM modeling]
    ii. Potential pilot projects
    iii. [PNM conclusions]

DETERMINATION OF THE RESOURCE PORTFOLIO:

A. To identify the most cost-effective resource portfolio, utilities shall evaluate all supply- side resources, energy storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.
B. The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.
C. The utility shall consider and describe ways to mitigate ratepayer risk.
D. Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:
(1) load management or modification and energy efficiency requirements;
(2) renewable energy portfolio requirements;
(3) existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions;
(4) fuel diversity;
(5) susceptibility to fuel interdependencies;
(6) transmission or distribution constraints; and
(7) system reliability and planning reserve margin requirements.
E. Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.

Proceedings of the ASME 2022 16th International Conference on Energy Sustainability
ES2022
July 11-13, 2022, Philadelphia, PA

ES2022-81870

PROBABILISTIC MODELING OF CLIMATE CHANGE IMPACTS ON RENEWABLE ENERGY AND STORAGE REQUIREMENTS FOR NM'S ENERGY TRANSITION ACT

Clifford K. Ho, Erika L. Roesler, Tu Nguyen, and James Ellison
Sandia National Laboratories, Albuquerque, NM, USA

ABSTRACT

This paper provides a study of the potential impacts of climate change on intermittent renewable energy resources, battery storage, and resource adequacy in Public Service Company of New Mexico's Integrated Resource Plan for 2020 – 2040. Climate change models and available data were first evaluated to determine uncertainty and potential changes in solar irradiance, temperature, and wind speed in NM in the coming decades. These changes were then implemented in solar and wind energy models to determine impacts on renewable energy resources in NM. Results for the extreme climate-change scenario show that the projected wind power may decrease by ~13% due to projected decreases in wind speed. Projected solar power may decrease by ~4% due to decreases in irradiance and increases in temperature in NM. Uncertainty in these climate-induced changes in wind and solar resources was accommodated in probabilistic models assuming uniform distributions in the annual reductions in solar and wind resources. Uncertainty in battery storage performance was also evaluated based on increased temperature, capacity fade, and degradation in round-trip efficiency. The hourly energy balance was determined throughout the year given uncertainties in the renewable energy resources and energy storage. The loss of load expectation (LOLE) was evaluated for the 2040 No New Combustion portfolio and found to increase from 0 days/year to a median value of ~2 days/year due to potential reductions in renewable energy resources and battery storage performance and capacity. A rank-regression analyses revealed that battery round-trip efficiency was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. An increase in battery storage capacity to ~30,000 MWh from a baseline value of ~14,000 MWh was required to reduce the median value of LOLE to ~0.2 days/year with consideration of potential climate impacts and battery degradation.

Keywords: Climate change; probabilistic modeling; battery storage; PNM Integrated Resource Plan

1. INTRODUCTION

In January 2021, the Public Service Company of New Mexico (PNM) issued its fifth Integrated Resource Plan (IRP), "PNM 2020-2040 Integrated Resource Plan," which included carbon-free electricity generation portfolios by 2040 [1]. PNM is a regulated utility and NM's largest energy provider with currently over 500,000 residential and business customers and ~3 GW of generation capacity. The PNM 2020-2040 IRP included portfolios to meet NM's Energy Transition Act, which requires 100% of electricity generation to be carbon free by 2045. PNM intends to meet that goal by 2040 and includes two different portfolios: a Technology Neutral scenario that includes hydrogen combustion turbines (initially powered by natural gas through the 2020s), and a No New Combustion scenario that relies primarily on solar, wind, and battery storage (Figure 1).

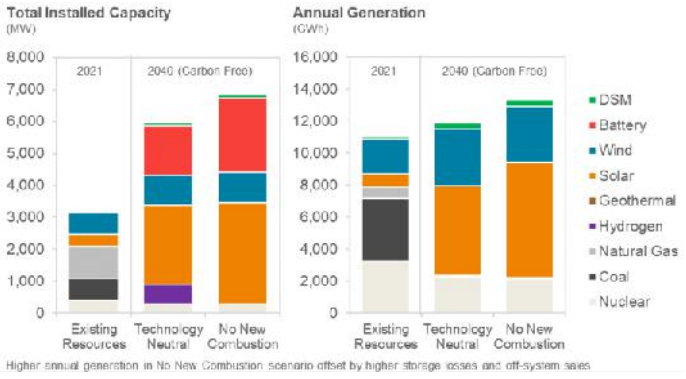


FIGURE 1: PNM PORTFOLIOS FOR CARBON-FREE ELECTRICITY PRODUCTION IN 2040 [1].

In the PNM 2020-2040 IRP, treatment of uncertainty and sensitivity analyses focused primarily on demand-side uncertainty. Climate change and potential impacts on intermittent wind and solar resources were not considered. In

© 2022 by ASME

addition, uncertainties in large-scale, long-term performance and reliability of battery storage systems were not considered; the battery storage system was assumed to operate at nameplate capacity for its entire 20-year lifetime (due to contracted maintenance and servicing of the systems).

The objectives of this study were to develop a probabilistic model and framework to evaluate inherent uncertainties in the energy resources and storage assumed in the PNM 2020-2040 IRP:

- Long-term changes in solar and wind resources caused by climate change
- Uncertainties in battery performance caused by capacity fade, degradation in round-trip efficiency, and long-term temperature increase caused by climate change
- Impact on the annual loss of load expectation (LOLE) and required energy storage

Probabilistic models were developed to evaluate the hourly energy balance each year given uncertainties in the renewable energy resources and energy storage. The loss of load expectation (LOLE) was probabilistically evaluated for the 2040 No New Combustion portfolio considering potential reductions in renewable energy resources and battery storage.

2. CLIMATE CHANGE MODELING

2.1. Climate Data Source and Methods

Three simulations from the Department of Energy's Energy Exascale Earth System Model (E3SM) were chosen from the Earth System Grid Federation Climate Model Intercomparison Project – version 6 (CMIP6) repository [2-5]. The CMPI6 simulation set contains output contributed from earth system modeling centers. This set includes simulations representing the earth system response under various, prescribed forcing scenarios. For this study, the three simulations chosen were a baseline simulation called pre-industrial control (piControl), a moderately warming simulation called historical, and a highly warming simulation called SSP585. The three simulations were from the 'r1i1p1f1' variant identification, meaning the first realization, first initialization, and same physics and forcing. The data were all written in the form of monthly averages with more details below.

The baseline simulations include prescribed greenhouse gas concentrations, such as CO_2, set to values at a time in human history where anthropogenic signatures were not distinguishable on the temperature of the atmosphere. These baseline simulations start in the year 1850 and usually run with that concurrent year, 1850, for several hundred years. The purpose of the duration of these simulations is to emulate the earth system climate variability and seasonality so that statistically significant values for a baseline, unperturbed earth, can be compared against a simulated earth with increasing anthropogenic signatures such as increasing greenhouse gas concentrations. Table 1 lists the description of data used for the Preindustrial control, baseline data. Because this data set has no induced warming on the earth system, it was also referred to as the 'no climate change' scenario for this work.

The historical simulation dataset, also described in Table 1, uses CO_2 concentrations prescribed or calculated from years 1850 to 2014. The earth system will be warming due to increased greenhouse gas concentration build-up over this time period, so this dataset was referred to as the 'low climate change' scenario. The last simulation dataset used is called SSP585. It was developed as an update of the high-emission 'business as usual' IPCC RCP8.5 scenario [2, 5]. This dataset has the highest amount of warming of the three and is called 'high climate change' in this work.

TABLE 1. DESCRIPTION OF DATA SOURCES FROM SIMULATIONS USED FOR THREE CLIMATE CHANGE SCENARIOS OVER NEW MEXICO.

Scenario	Data and Simulation Description
No Climate Change	- ECA version of Preindustrial control simulation - CR-1.7 CMIP-6.2, ScenarioMIP - Concurrent year 1850 year for 165 years, monthly averages
Low Climate Change	- Update of RCP8.5 based on SSP5 - CR-1.7 CMIP-6.2, ScenarioMIP - Jan 1850 - Dec 2014, monthly averages
Extreme Climate Change	- Update of RCP8.5 based on SSP5 - CR-1.7 CMIP-6.2, ScenarioMIP - 1032 monthly-averaged time points, Jan 2015-Dec 2021

The variables chosen for analysis are fundamental variables influencing wind energy production, solar energy production, and battery storage efficiency. Table 2 lists the variables chosen from the E3SM CMIP6 database. For wind power generation, power is a function of wind speed cubed. The variable for near surface wind, sfcWind, was used instead of wind at hub height. 'sfcWind' is stated to be the wind at about 10 meters off the ground surface. It should be noted that the wind speed within the boundary layer generally follows a log wind profile as the surface frictional effects are less impactful as you move away from the surface. Therefore, any additional low level increase in height – 10s to 100s of meters will give 'generally' an increase in wind speed and therefore power. This variable was readily available and required no additional data processing after downloading.

Solar energy production from solar installations relies on direct and diffuse solar radiation. The potential for solar energy production is computed from the Global Horizontal Irradiance (GHI), which is the sum of Diffuse Horizontal Irradiance (DHI) and Direct Normal Irradiance (DNI) multiplied by the cosine of the solar zenith angle (z), $GHI = DHI + DNI \cdot \cos(z)$. Given radiation parameterizations in earth system models are column-based physics with no radiation interaction between columns, the surface downwelling shortwave radiation is associated with the needed GHI variable. Clear-sky shortwave radiation at the surface from climate models is DNI, but the diffuse radiation that could be scattered equally in all directions from molecules,

© 2022 by ASME

aerosols, and clouds is more difficult to ascertain from earth system model output. Ground reflectance could also be included in GHI, but this contribution is usually low compared to DHI and DNI. It was determined that the variable 'rsds' would be the most appropriate choice for determining solar variability with a changing climate.

TABLE 2. LIST OF VARIABLES FOR USED TO DETERMINE RESOURCES UNCERTAINTY FOR SOLAR, WIND, AND BATTERY.

CMIP6 Variable	Renewable Resource	Description
sfcWind ($m\ s^{-1}$)	Wind power	Near-surface (usually, 10 meters) wind speed in Time, (Latitude, Longitude) (1 degree) (180, 360)
rsds ($W\ m^{-2}$)	Solar power	Surface Downwelling Shortwave Radiation in Time, (Latitude, Longitude) (1 degree) (180, 360)
Ts (K)	Solar power, Battery storage	Surface Temperature in Time, (Latitude, Longitude) (1 degree) (180, 360)

The time-averaged global annual mean of the three simulations and the variables of interest give a notional sense of the global variability and magnitudes of the three variables, showing differences in energy, temperature, and wind over New Mexico compared to other regions of the globe. Qualitatively, there is little spatial difference between the 'No Climate Change' and 'Low Climate Change' scenarios. The 'High Climate Change' scenario shows significant warming in the Arctic and in New Mexico. Wind speeds and surface downwelling shortwave radiation over New Mexico do not change as much as temperature across the three scenarios.

The time series trends for each of the variables for each of the simulation is shown in Figure 2. The simulation output is in the form of monthly means, and a 48-point running average was computed for each of the time series. Three area-weighted averages were computed for comparison: the entire globe, the contiguous United States (i.e., lower 48 States), and the State of New Mexico. In the 'No Climate Change' scenario, it is expected for there to be little-to-no-trend over the time series because the earth system is in pre-industrial energy equilibrium. The 'Low Climate Change' scenario shows increasing surface temperatures in the latter portion of the simulation, which is consistent with observations and the basis upon which this simulation is designed. The trends in the surface downwelling shortwave radiation and near-surface wind speed also show minute changes in the end of the simulation. Impacts in the simulation of coarse spatial resolution and parameterizations, or not enough forcing to cause a discernable change in the time series are all probably causes for these two variables' trends. The 'High Climate Change' scenario shows the expected increase in surface temperature, a reduction in near-surface wind speed, and no discernable change in the surface downwelling shortwave radiation. There is little confidence in the trends of wind and radiation for this scenario (see Section 2.3).

2.2. Climate Modeling Results

Bounds and trends are needed for the solar and wind resource calculations. Because climate models are inherently uncertain in that they represent chaotic systems with much dependence on initial conditions for solutions, it was decided to take averages of the three simulations over the state of New Mexico. New Mexico's land area is small compared to the global surface, and instances of the climate over New Mexico for any given month could be representative of the past, current, and future climate. Table 3 shows the time averages and standard deviations over New Mexico for the entire simulations for the three variables.

From Table 3, there is no trend in surface downwelling shortwave radiation (i.e., solar radiation) over the 'No', 'Low', and 'High' climate change scenarios. The near-surface wind decreases slightly from 'No' to 'High' climate change scenarios, and the temperature increases by 5 K from 'No' to 'High' climate change.

TABLE 3. AVERAGES AND STANDARD DEVIATIONS OF SOLAR RADIATION, SURFACE TEMPERATURE, AND SURFACE WIND FROM E3SM CMIP6 SCENARIOS.

Variable	Scenario	Average	Standard Deviation
Solar, rsds ($W\ m^{-2}$)	No climate change	226.7	75.21
	Low climate change	221.0	76.51
	High climate change	224.4	75.56
Surface Temperature, Ts (K)	No climate change	283.0	9.250
	Low climate change	283.1	9.244
	High climate change	288.5	9.613
Surface Wind, sfcWind ($m\ s^{-1}$)	No climate change	4.239	0.7831
	Low climate change	4.215	0.8471
	High climate change	3.871	0.8012

2.3. Comparison with Other Studies

This study is not alone in assessing climate change impacts on renewable energy resources. Global, national, and regional bodies of research exist for specific technologies as well as system-level studies. For future reference, Solaun & Cerdá [6] provides global overviews of climate change effects on renewable resources. Additionally, a nationwide assessment of energy demand under different emissions scenarios stated that electricity demand will increase on average of 10%, which included power system generation with power system planning and operations [7]. In the literature review performed for this study, it was found that there is unanimous uncertainty in the magnitude and direction of energy resources being impacted regionally and under different future climate scenarios. The focus now narrows to literature that has the most direct application or comparison with this work, this section provides

© 2022 by ASME

an overview of select literature reporting for the southwestern United States. For neighboring state Texas for solar and wind, wind increases by 1-4%, but there is no clear concurrence on solar production for future years 2041-2050 [8, 9].

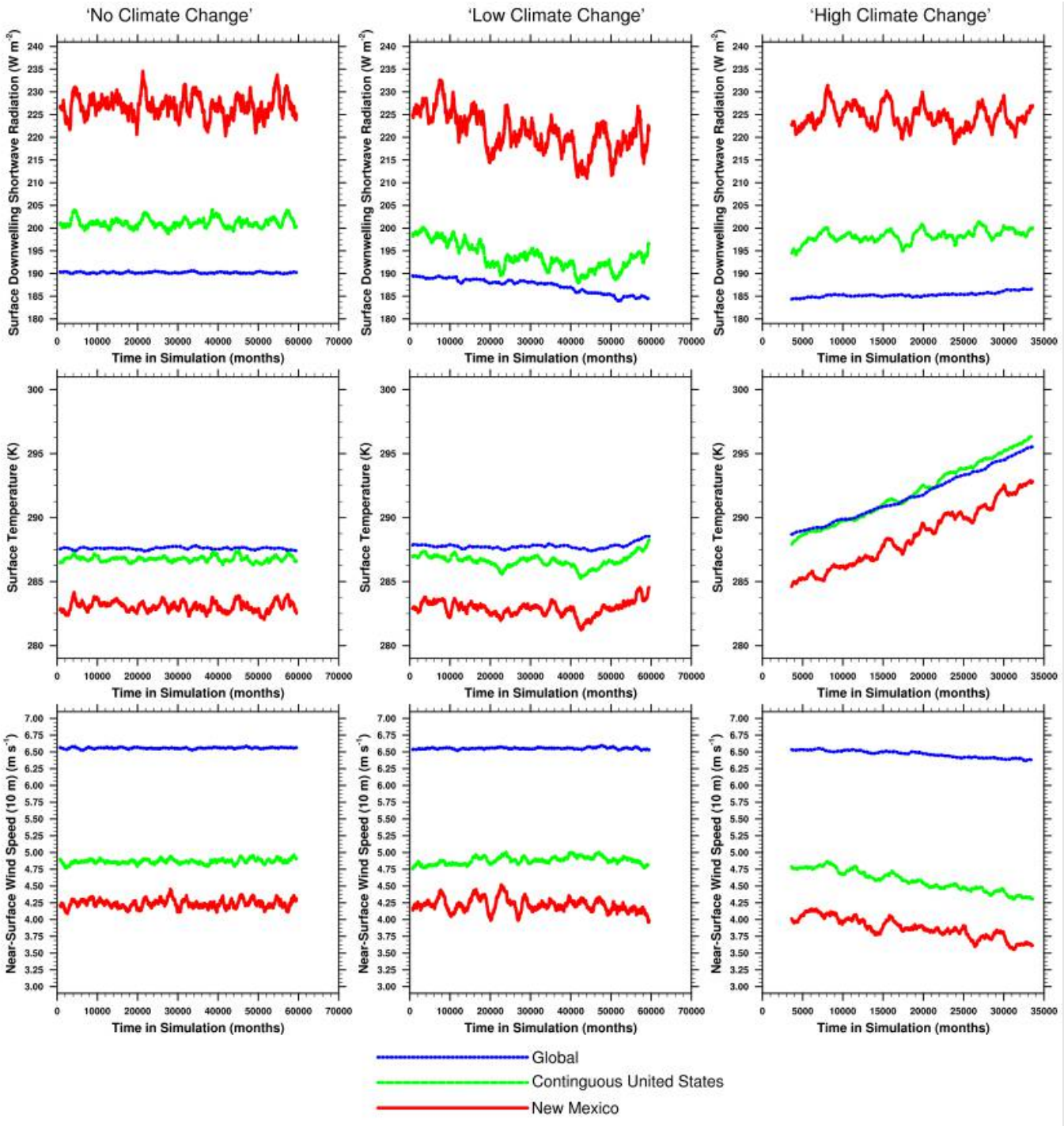


FIGURE 2. TIME SERIES OF THE SURFACE DOWNWELLING SHORTWAVE RADIATION, SURFACE TEMPERATURE, AND NEAR-SURFACE WIND SPEED FOR THE 'NO CLIMATE CHANGE' (ECA_PICONTROL), 'LOW CLIMATE CHANGE' (HISTORICAL), 'HIGH CLIMATE CHANGE' (SSP585) CMIP6 E3SM SIMULATIONS FOR GLOBAL, CONTIGUOUS UNITED STATES, AND NEW MEXICO AREAS. THE TIME SERIES REPRESENTS MONTHLY MEANS FROM THE SIMULATION DATA, AND THE DATA WERE SMOOTHED BY APPLYING A 48-POINT RUNNING AVERAGE.

© 2022 by ASME

Wind power, although very specific to region, show both an increase and decrease in potential wind energy production through the variability of wind speed projections over different seasons and emissions scenarios [8-10]. Often, a higher-resolved North American regional atmospheric model such as the NACORDEX (North American component of the international CORDEX (Coordinated Regional Downscaling Experiment) [11], or WRF (Weather Research and Forecasting model) [12] is used in these studies and compared with a courser resolution global model [13]. Recently there have been observations that winds, including surface winds, are slowing globally. A recent review paper suggests that the data supporting this claim might be region-specific, and more information about internal modes of climate and changes to land use, land cover is needed before understanding this theoretical trend [14]. The previous works considered for comparison here did not mention the observational trend of wind stillness in their findings.

For solar power, there appears to be no agreement that solar resources will increase or decrease for a given future, warmer climate across the western United States [10, 15-18]. Even comparisons using 37 earth system models run under the CMIP5 protocols showed an increase in solar production for the southern United States. However, when 14 regional climate models (i.e., higher spatial resolution) were used, the solar production was calculated to decrease [19]. Although unresolved cloud behavior seems to be a likely culprit in explaining the differences between the global and regional models, differences in cloud properties alone could not explain differences, so it was assumed aerosols were also playing a role with an approximately $\pm$ 2.5% change in solar radiation at the surface. However, it should be noted that aerosol concentrations and pathways contain high uncertainty and speculation in future climate projections.

For general climate model bias as it relates to observations, climate modelling groups publish simulated model bias compared to global observations. The climate model used in this work, E3SM, has reported a negative bias of shortwave (visible) cloud radiative effects compared to observations, but with little to no precipitation bias compared to global satellite observations. This could imply that E3SM rains-out the simulated cloud, leaving too-little cloud mass after a precipitation event. Additionally, E3SM has a strong aerosol-related effective radiative forcing and a high equilibrium climate sensitivity. This means the SSP585 scenario is likely to project a warmer earth than other models at the end of the simulation in year 2100.

2.4. Climate Modeling Discussion

In gathering information needed to compute future climate change scenarios, a list was developed of potential future work that could analyze details of future climate change impacts to renewable energy production.

- Models that have high spatial and temporal resolution produce different trends than global models. Despite high variability and uncertainty, understanding the benefits of additional information at the cost of computer time is still undetermined for New Mexico [9]. Understanding downscaling for this problem is needed.
- In the CMIP6 database, the climate variable standards for solar radiation did not separate the Global Horizontal Irradiance (GHI), into the terms of Diffuse Horizontal Irradiance (DHI) and Direct Normal Irradiance (DNI), $GHI = DHI + DNI \cdot \cos(z)$. Understanding predictions and baseline results of diffuse and direct will help understand model bias in changes in aerosol optical depth and cloud cover.
- The results presented here are monthly means which do not account for nighttime and daytime differences with high time resolved datasets. For solar power production, nighttime values will be different than daytime, and wind production might also change over a diurnal cycle. Finding data in the CMIP6 archive or going to individual model output will clarify the computed answers and could change the uncertainty distribution.
- Wind turbines have cut-in and cut-out speeds. Higher time-resolved values for wind will show when wind speed is too great for turbines.
- Although this is not expected to change the findings of this report, using data from the CMIP6 archive that has more vertical levels, or altitude values, so that hub height and not sfcWind is used to calculate the wind power generation.
- Trends for wind slowing and stillness over New Mexico should be investigated in both observational data and simulated future climate projections.
- The E3SM baseline simulation (i.e., the pre-industrial control) should be compared to reanalysis and other weather-based datasets to improve the understanding of the baseline bias.
- Other studies have used field-acquired data with machine learning sorting algorithms to determine potential weather impacts on renewable energy production [20]. Given the difficultly of earth system models to simulate extremes, linking realistic data with future projections is an area of potential research.
- How can the unresolved clouds, and uncertainty in cloud cover be accounted for? Jiménez et al. [21] looked at 6-hour ensemble simulations with WRF Solar for unresolved cumulus with observations and found that parameterizing radiative effects of deep and shallow cumulus is necessary to reduce a 55% overprediction in GHI. A positive GHI bias has been reported in WRF over Albuquerque, New Mexico [12]. How can this cloud bias be accounted for in global earth system models?

Other options for increasing resolution include using variable or refined resolution atmospheric models. These configurations could also be linked with Sun4Cast and weather prediction to compute solar variability [17]. Wang et al. [22] used CESM-VR with clustering for wind resources over California and found statistically significant changes in capacity. They found through clustering weather patterns that over a 36-year period, wind regimes occurring on “hot summer days increased at half a day per year and stagnant conditions increased

© 2022 by ASME

at one-third days per year." Using downscaled MERRA with WRF and energy firm data helped drive this finding [23].

3. CLIMATE CHANGE IMPACTS ON SOLAR AND WIND POWER GENERATION

3.1. Wind and Solar Resources in New Mexico

Table 4 summarizes the existing wind resources in NM operated by PNM, and Table 5 summarizes the existing and pending solar resources in NM operated by PNM. The older wind turbines are at a hub height of 80 meters, and the newer ones are at 90 meters. PNM will likely add more wind in the future, but the timing and amount are uncertain. Additional wind capacity will probably also be in Torrance County (near Clines Corners) because of access to PNM transmission.

TABLE 4. WIND RESOURCES IN NEW MEXICO.

Existing Wind PPA Resources	County	Net Capacity (MW)	Turbine Capacity (MW)	Hub Height (m)
NM Wind Energy Center	Quay	200	1.5	80
Casa Mesa Wind	Quay	50	2.5	89
La Joya 1	Torrance	166	2.5	89
La Joya 2	Torrance	140	2.5	89
Red Mesa Wind	Sandoval	102	1.6	80

TABLE 5. LIST OF PRC-APPROVED AND PENDING-APPROVAL LARGE SOLAR ARRAYS IN NEW MEXICO.

Site	AC Capacity (MW)	Status
Arroyo	300	PRC-approved
Jicarilla 1	50	PRC-approved
San Juan	200	PRC-approved
Rockmont*	100	PRC-approved
Atrisco	300	Submitted Application
Jicarilla 2	50	Submitted Application
Sky Ranch	190	Submitted Application
Encino North	50	Submitted Application

3.2. Impact of Modeled Climate Change on PNM Wind Power Generation

Using hourly 2012 wind speed data [24] for a point representing the NM Wind Energy Center wind generator (204 MW installed capacity), we found that that a drop of 8.7% in wind speed each hour yielded a *13% drop in total wind energy output* for the year. The following sections describe these findings.

3.2.1. Methodology

2012 wind speed data for a site representing the NM Wind Energy Center were obtained on an hourly basis from the Wind Prospector [24]. Specifically, wind speed data for the cell located at lat: 34.65, long -104.04 (Site ID: 874603 on the Wind Prospector [24]) was downloaded on an hourly basis for 2012. Turbines are classified as Class I, II, or III with average design wind speeds of 10, 8.5, and 7.5 m/s, respectively, as outlined in the International Electrotechnical Commission (IEC) 61400-1 standard [25].

The wind power equation can be expressed as follows: Power (W) = ½ ρ A V^3 C, where ρ = air density (~1.2 kg/m^3 at sea level), V = velocity in (m), A = area swept by the wind turbine blades (m^2), and C = ratio of power extracted by wind turbine to total available in the wind resource, where 0.59 (the Betz Limit) is the theoretical maximum [26]. Because the kinetic power available in wind is proportional to the cube of the wind velocity, a wind turbine experiencing 9 m/s winds is exposed to more than three times the force of a wind turbine experiencing 6 m/s winds. It would not be economical to design turbines for low-wind sites to the same standards as high-wind sites; therefore, different design standards were established for sites with different average levels of wind.

Because Class II turbines are the most common, this study determined how changes in wind speed impact the power production for Class II turbines using a wind-speed-to-power conversion curve [27] (Figure 3). Wind speed data were not obtained for each individual wind turbine—the simplifying assumption was that since we are interested in the difference between generation at a reference wind speed and a post-climate change wind speed, it is reasonable to not take individual turbine locational differences into account.

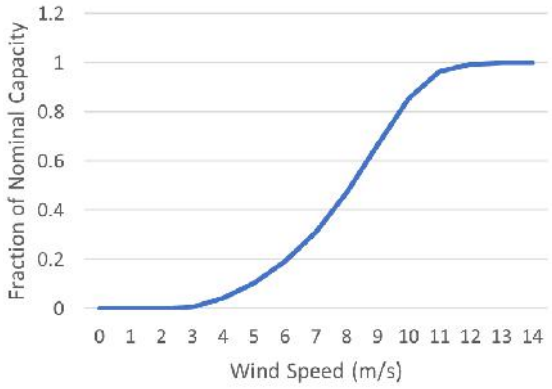


FIGURE 3. POWER CURVE FOR IEC CLASS II TURBINE

The wind farm output in each hour was calculated using the Wind Prospector dataset for wind speed in 2012 as input to the power curve in Figure 3. The wind velocity in that dataset was reduced in each hour by 8.7% to reflect the modeled change in the High Climate Change scenario. Comparing the total amount of power generated in the reference case to the High Climate Change scenario, the study team found that the 8.7% drop in wind speed in each hour led to *an overall 13% drop in wind generation output.*

The annual capacity factor calculated for the wind farm (using a single-point representation of that wind farm) was calculated at 50% for the reference case, and 43.5% for the High Climate Change scenario. 50% is an unusually high capacity factor for a wind farm and suggests that more detailed modeling

© 2022 by ASME

may be warranted. Nevertheless, we are more interested in the difference between the two scenarios. It is reasonable that the percentage decline in power generation should be greater than the percentage decline in wind speed.

An 8.7% reduction in wind speed in each hour does not yield an 8.7% reduction in power output because the wind speed to MW output conversion formula is not linear. Also, there is about a 30% decrease in the number of hours the wind speed is 11 m/s or more (which is the point above which power output is at full capacity). There is also an increase in the number of hours the wind speed is 4 m/s or less (the point where wind power output is zero). The net effect is that there are about 11% more hours where the wind speed does not yield a 100% or a 0% capacity factor but is along the variable portion of the curve. In addition, the slope in the middle of the curve is quite steep – going from 7 m/s to 8 m/s causes output to increase by about 50% (from 31 MW to 47 MW for a 100-MW wind farm).

3.3. Impact of Modeled Climate Change on PNM Solar Power Generation

The potential impact of climate change on PNM solar power generation was modeled using two different methods. One method (called the "Specific" method) involved calculating the output for the Arroyo solar plant given 5-minute satellite weather data, and then adjusting the solar irradiance and increasing the ambient temperature by the climate-change-scenario amounts. Another method (called the "General" method) focused on calculating the impact of climate change on a generic solar PV facility.

The two methods arrived at the same conclusion – a 2.5% drop in solar irradiance and a 5.5 °C rise in ambient temperature (in all hours) would result in roughly a *4% drop in solar PV generation.* Based on results from the Specific method, about half of this drop is due to the decrease in solar irradiance, and about half is due to PV efficiency loss from higher ambient temperatures. The following sections provide more details.

3.3.1. Climate Scenario Selection

Based on the climate modeling results given in Table 3, we see that a simulated worst-case scenario for solar PV power production would be a 2.5% drop in solar irradiance (with solar irradiance dropping from 226.7 W/m^2 in the reference case to 221.0 W/m^2 in the "Low Climate Change" case), and a 5.5 °C increase in average ambient temperature (10 °C average in the reference case to 15.5 °C in the "High Climate Change" case). A great deal of uncertainty exists in these preliminary climate models, and it is possible that actual climate change impacts may be less or greater than our simulated "worst-case." Our primary goal was to develop a methodology and framework that can be used for future analyses with more refined climate models and data.

3.3.2. Methodology – Specific Method

A single, large solar PV plant was modeled using pvlib python, which is a community-supported tool that allows for detailed simulation of the performance of photovoltaic energy systems [28]. It was originally taken from the PVLIB MATLAB toolbox developed at Sandia National Laboratories and implements many of the models and methods developed there.

The location chosen for the plant was the site of the future Arroyo solar PV power plant (in McKinley County, NM – about 10 miles East of the Chaco Culture National Historical Park). Given that this plant is the largest plant approved by the NM PRC to date, and that it is a single-axis tracking plant (as all future PV plants for PNM are likely to be), we felt that this plant is sufficiently representative of the PV plants that will make up most of PNM's solar PV plant capacity in the future and that it can be used as a proxy for PNM solar PV plants in general.

Solar irradiance (and ambient temperature) data were downloaded from the National Solar Radiation Database (NSRDB) [29] at a five-minute resolution for the cell with coordinates 35.96° latitude and -107.63° longitude. This cell represents an area of 4 km^2 (as the spatial resolution is 2 km by 2 km). The NSRDB identifier for this cell is 787961.

The solar irradiation data used in this model, specifically, are Diffuse Horizonal Irradiance (DHI), Direct Normal Irradiance (DNI), and Ground Horizontal Irradiance (GHI), all expressed in W/m^2. DHI is the amount of radiation received per square meter by a surface (not subject to any shade) that does not arrive on a direct path from the sun (in other words, light that is scattered by molecules in the atmosphere). DNI is the solar radiation per square meter by a surface that is always perpendicular to the light coming straight from the sun (given its current position in the sky). GHI is the total amount of shortwave radiation received from above by a surface horizontal to the ground. The relationship between these three measurements of solar irradiation is given by:

$$GHI = DNI * \cos(\theta) + DHI$$, where θ is the solar zenith angle (directly overhead would be $\theta = 0$)

The PV system simulated in pvlib python was assumed to be a single-axis tracking plant with an inverter load ratio (ILR) of 1.3. In other words, the PV panel capacity for this plant was set at 1.3 times the capacity of the AC inverter. The actual Arroyo plant will, in fact, have an ILR of 1.3, and it is likely that future solar PV plants providing power will have a similar ILR. This is because it is not economical to size the inverter at the full output capacity of the PV panels, as this full capacity would be used only for a small fraction of time. In addition, setting the inverter at a smaller size than the PV panels allows for a more even power output profile in the middle of the day.

The system size chosen was a normalized 1.3 MW DC, 1 MW AC system. First, the reference case was generated by loading in the five-minute solar irradiance and ambient temperature data for 2018 and running the model. The model generated an AC power output dataset for a year (at a five-minute resolution) based on the plant type, location, solar irradiance, and ambient temperature data given.

Next, the climate change cases were generated by modifying the weather inputs to account for a Low Climate Change scenario, a High Climate Change scenario, and a Combination scenario. Specifically, GHI, DHI and DNI were reduced at all times by the amount specified in each scenario, and the

© 2022 by ASME

temperature was increased at all times by the average ambient change specified. New model runs were made which took this modified weather data as input and produced new AC power output datasets for a year (also at a five-minute resolution). The power output for each scenario run was summed over the year, and the total annual power generated was compared with the reference run. The changes used for these scenarios, as well as the results of the model runs, are summarized in Table 6.

TABLE 6. SOLAR PV SCENARIOS AND RESULTS.

Scenario	Change in Solar Irradiation	Change in Average Ambient Temperature	Annual Drop in Solar Output
Low Climate Change	-2.5%	0° C	*1.9%*
High Climate Change	-1%	+5.5° C	*2.9%*
Combination	-2.5%	+5.5° C	*4.1%*

The Combination scenario, which posits a 2.5% drop in solar irradiation and a 5.5 °C rise in ambient temperature, led to roughly a 4% decrease in solar PV power production as compared to the reference run.

3.3.3. Methodology – General Method

In this method, the cell temperature (Tcell) is calculated based on the insolation (S), the ambient temperature (Tamb) and the normal operating cell temperature (NOCT) that is measured at 800 W/m^2 and 20 °C ambient as follows:

$$\text{Tcell (°C)} = \text{Tamb}+(\text{NOCT}-20)*S/800$$

Therefore, given ambient temperature and insolation differences, the cell temperature change can be calculated as following:

$$\Delta\text{Tcell}=\Delta\text{Tamb}+(\text{NOCT}-20)*\Delta S/800\ °\text{C}$$

Since power-temperature coefficient, C (% per °C) of a PV panel is often given based on testing data, the percentage change in output generation of the PV panels can be specified:

$$\Delta\text{Pout (\%)} = C*\Delta\text{Tcell}$$

Given 5.5 °C ambient temperature rise, around 2.5% insolation reduction and -0.3% power-temperature coefficient, the overall reduction in annual generation of PV system is calculated and compared with the baseline case. The results show that PV generation drops about 4%, same as the Specific Method.

4. CLIMATE CHANGE IMPACTS ON BATTERY STORAGE

Operating temperature is one of the main factors that significantly affect the life span as well as the performance of li-ion batteries (LiB). While high temperature increases the formation and modification of the surface film on batteries' electrodes making them degrade faster, low temperature slows down the electrochemical reactions within the batteries making them less efficient. Furthermore, extremely low or high temperature can also create serious damage to LiBs. Therefore, for grid-scale battery energy storage systems (BESS), heating, venting and air conditioning (HVAC) systems are often required to maintain the battery enclosure's temperature within an operating range. Since the change in ambient temperature will impact HVAC's operation, it will also impact the overall performance of a BESS.

4.1. Impact of Temperature Change on Battery Storage

In this section, the impact of climate change is seen as the impact of ambient temperature rise on the performance and degradation of Li-ion BESS. Three scenarios of temperature rise are considered including:

- Scenario 1 – Nominal: this scenario assumes the ambient temperature would not change in the next 24 years. This is used as the baseline to evaluate the other two scenarios.
- Scenario 2 – Moderate temperature rise: this scenario considers 2-degree temperature rise in the next 24 years.
- Scenario 3 – Extreme temperature rise: this scenario considers 5-degree temperature rise in the next 24 years.

Grid-scale Li-ion BESSs are required to sit outdoors by the current safety codes. Therefore, these BESSs are often packed as modules that are contained in standard shipping containers. The module size often varies with applications and manufacturers; however, in this work we model a typical 1MW/4MWh module contained within a 20-ft standardized shipping container. Just as modules can be stacked to achieve a larger system, so too this model can be scaled to model the systems of different sizes. The purpose of this model is to study the overall performance of BESS given the ambient temperature and the loading (charge/discharge) profile of the BESS. For simplification, the following assumptions are made:

- BESS alternatively charges and discharges every 12 hours
- BESS loss is purely heat loss
- Battery temperature is equal to the enclosure temperature
- The container is not insulated

The input parameters of the model are given in Table 7.

TABLE 7. PARAMETERS USED IN HVAC MODELING OF BESS POWER CONSUMPTION.

Parameters	Unit	Value
BESS Power Rating	MW	1
BESS Energy Capacity	MWh	4
LiB Specific Weight	Wh/kg	160
Mass, m	kg	25000
Round-trip Efficiency	%	90
One-way Efficiency	%	95
BESS Specific heat, c_p	J/kg.K	1000

© 2022 by ASME

Parameters	Unit	Value
HVAC Capacity	BTU/hr	80,000 (23,400 W)
Container Surface Area	m^2	67.63
Container Emissivity	-	0.8
HVAC Power Rating	W	8000
HVAC Duty Cycle	%	40
HVAC Max Coefficient of Performance	-	4

The container's change in temperature, ΔT (K), at each time step, *i,* is calculated using an energy balance:

$$\Delta T_i = \frac{\dot{E}_{in,i} - \dot{E}_{out,i}}{mc_p}\Delta t \quad (1)$$

where $\dot{E}_{in,i}$ is the heat generation (W) caused by the battery inefficiency (assumed to be lost entirely to resistive heating) during charging and discharging, $\dot{E}_{out,i}$ is the heat dissipation from radiation and conduction from the shipping container and convection via HVAC, m is the mass of the BESS and container (kg), c_p is the specific heat (J/kg-K), and Δt = 1 hr (3600 s). In the model, the HVAC is on at its rated power if the container's temperature is above 45 °C, off if the temperature is below 25 °C, and holding its status (on or off) if the temperature is decreasing below 45 °C or increasing above 25 °C. In each scenario, the model is used to simulate the container temperature at each hour throughout a year. The HVAC's energy consumption for a 4 MWh BESS is calculated accordingly and compared between different scenarios. The results are shown in Table 8.

TABLE 8. MODELED ANNUAL HVAC ENERGY CONSUMPTION AS A FUNCTION OF AMBIENT TEMPERATURE RISE.

Climate Scenario (ambient temperature)	HVAC Annual Energy Consumption (MWh)	HVAC Annual Energy Consumption Change (%)	Ratio (%) of HVAC Annual Energy Consumption to Annual Battery Throughput Energy[1]
Current conditions	23.5	0	1.6%
2 °C increase	25.0	12.1%	1.7%
5 °C increase	27.3	22.4%	1.9%

[1]Four MWh/discharge x 365 discharges/yr = 1,460 MWh of annual battery throughput energy

As seen in Table 8, the HVAC annual energy consumption increases as the temperature rises. This is because ambient temperature rise will reduce the heat dissipation through radiation, convection, and conduction making the HVAC work harder to maintain the operating temperature range. Significant increase in HVAC energy consumption will increase the overall load of the system thereby decreasing the net impact of BESSs. However, the relative impact of an ambient temperature rise of up to ~5 °C on increased HVAC energy consumption is predicted to yield less than 1% change in the total annual battery throughput energy. Therefore, the uncertainty on increased temperatures on HVAC parasitic power consumption is not directly included in the probabilistic simulations; the uncertainty is assumed to be subsumed by the uncertainty in the capacity fade and round-trip efficiency described in the next section.

4.2. Impacts of Capacity Fade and Round-Trip Efficiency on Battery Storage

Capacity fade and round-trip efficiency can impact the available throughput energy of battery storage systems. Although not necessarily tied to climate change, this study included uncertainty in capacity fade and round-trip efficiency in the probabilistic simulations.

Capacity fade is a condition in which the total energy capacity that a battery can deliver reduces with use and is dependent on a number of factors including ambient temperature, discharge rate, and depth of discharge. Preger et al. [30] performed a multi-year test of different lithium-ion cells under varying discharge conditions and found that the number of cycles to reach an 80% capacity (20% capacity loss) ranged from only a few hundred cycles to several thousand cycles, depending on cell type and conditions. Spotnitz [31] reported that among different lithium-ion cell types, the capacity loss at 500 cycles ranged from ~12 – 24%. Based on these studies, we assume that the capacity loss of battery storage systems used by PNM may be up to 20% within a few years of deployment – before issues are identified and servicing or replacement of cells can be performed. A uniform distribution for battery capacity fade between 0 – 20% was therefore assumed and sampled for each annual realization of the hourly energy balance. This sampled value was used to reduce the total battery storage capacity prescribed in the 2040 No New Combustion scenario.

Preger et al. also evaluated the round-trip efficiency (energy out/energy in) of various lithium-ion cells and found that the initial round-trip efficiency varied between ~80% - 95%. After cycling to a capacity loss of 20%, the decrease in initial round-trip efficiency ranged from less than a few percent up to ~10% in many reported cases. Based on these studies, the round-trip efficiency (and impacts of potential degradation) for the battery systems used by PNM during any year in the probabilistic simulations was assumed to be uniformly distributed between 80 - 95%. The sampled round-trip efficiency was used to reduce amounts of energy added to the battery during any hour when supply exceeded demand for the No New Combustion scenario. For example, if the sampled round-trip efficiency for a given year was 90%, and the energy supply exceeded demand by 10 MWh during a given hour, the energy stored during that hour for later delivery was set equal to 0.9 x 10 MWh = 9 MWh (assuming that the total energy stored did not exceed the total nameplate capacity of all available battery storage systems, accounting for capacity fade described above).

© 2022 by ASME

5. PROBABILISTIC ANALYSIS OF CLIMATE CHANGE IMPACTS AND BATTERY PERFORMANCE

5.1. Modeling Approach

At each hour of the year starting at 12 AM January 1 and ending at midnight December 31, the energy, E_i (MWh), produced from all available generation sources in the 2040 No New Combustion scenario were summed, including uncertainty in intermittent wind and solar resources as impacted by climate-change modeling. In addition to variable solar and wind generation at each hour of the year, firm fixed resources (i.e., nuclear, geothermal) were added as prescribed by PNM (see Table 9). If the total generation exceeded the total load, L_i (MWh), at any hour, surplus generation was added to the battery storage (after adjustment for round-trip efficiency). If the generation was less than the load at that hour, energy was taken from battery storage. Checks were implemented to determine the minimum and maximum state of charge (SOC) of the battery storage system (in MWh) at each hour: (1) if generation was less than the load, and total SOC decreased to a value less than zero, the SOC was set to zero, and (2) if generation was greater than the load, and SOC increased to a value greater than the maximum battery storage capacity adjusted for capacity fade (*Fade*), the SOC was set equal to the maximum battery storage adjusted for capacity fade and battery round-trip efficiency (*RTE*). The SOC at the start of the year was assumed to be equal to 100%. The steps to calculate the SOC at each hour can therefore be summarized as follows:

$$SOC_i = SOC_{i-1} + \sum_i E_i - L_i \tag{2}$$

$$If\ \ SOC_i < 0,\ \ SOC_i = 0$$

$$elseif\ \ SOC_i > SOC_{\max}(1 - Fade_j),\ SOC_i = SOC_{\max}(1 - Fade_j)RTE_j$$

$$elseif\ \ \sum_i E_i - L_i > 0,\ SOC_i = SOC_{i-1} + \left(\sum_i E_i - L_i\right)RTE_j$$

where i is the hour of the year (1 to 8760) and j is the realization (1 to 100).

TABLE 9. SUMMARY OF FIRM FIXED RESOURCES ASSUMED FOR PNM 2040 NO NEW COMBUSTION SCENARIO (IN ADDITION TO SOLAR AND WIND GENERATION) [1].

Parameter	Value
Total energy efficiency* (MW):	95
Total demand response* (MW):	15
Total coal resources (MW):	0
Total nuclear resources (MW):	288
Total natural gas resources (MW):	0
Total geothermal resources (MW):	11
Total battery storage resource (MWh):	14,328
% battery capacity on Jan. 1 (hour 1):	100%

*Not used in probabilistic hourly energy balance.

Uncertainty distributions of wind and solar generation, battery RTE, and battery fade (Table 10) were sampled to create 100 realizations of annual energy balances for the 2040 No New Combustion scenario. All other input parameters (e.g., firm fixed resources, load) were not varied from the baseline values.

TABLE 10. SUMMARY OF UNCERTAINTY DISTRIBUTIONS IN PROBABILISTIC SIMULATIONS.

Parameter	Nominal Value*	Uniform Distribution Minimum	Uniform Distribution Maximum
Wind generation (MWh)	-13%	-50%	+50%
Solar generation (MWh)	-4%	-50%	+50%
Battery RTE	N/A	80%	95%
Battery capacity fade	N/A	0%	10%

*The nominal value for wind and solar generation represents the impact of climate change (see Sections 3.2 and 3.3) on baseline values provided by PNM using their historical capacity factors and expected generation capacity in the 2040 No New Combustion portfolio (see Sections 0 and 5.1.2).

In each realization, the loss of load expectation (LOLE) was determined as the number of days (hours divided by 24) in which the SOC was equal to zero during the year. The cumulative distribution function for the LOLE was plotted for all 100 realizations. The goal was to determine if the distribution of LOLE was significantly greater than the desired value of 0.2 days/year or less with the impacts of climate change and uncertainty in battery performance. If so, a sensitivity study would be performed to determine the additional battery storage capacity required to reduce the LOLE to 0.2 days/year or less.

5.1.1. Uncertainty in Wind Energy Resources

Historical average wind-generation capacity factors for each hour of the month were reported by PNM (2013 – 2019) [1], which reveals that wind generation typically peaks in the late afternoon and evening hours and subsides in the morning hours. Februrary through April are the most productive months for wind generation, while July and August are the least productive.

These hourly capacity factors were multiplied by the total expected wind generation capacity (956 MW) in the 2040 most cost-effective No New Combustion portfolio presented in the PNM 2020 – 2040 IRP [1] to yield baseline wind power generation values at each hour of the year. For simplicity, the wind generation for a specific hour of any given month was

assumed to be the same (e.g., the wind generation at 7 AM for each day in January was assumed to be the same; the wind generation at 3 PM for each day in July was assumed to be the same).

Uncertainty in these baseline values was accommodated by uniformly varying the baseline values by up to ±50% in the probabilistic simulations as summarized in Table 10. Although arbitrary, this uncertainty range was thought to be appropriate to accommodate uncertainty in not only the natural variability in

© 2022 by ASME

wind generation but also the unceratinty in the preliminary climate models. A sensitivity was also performed to determine the impacts of varying the uncertainty range on LOLE.

5.1.2. Uncertainty in Solar Energy Resources

Historical average solar-generation capacity factors for each hour of the month were reported by PNM (2013 – 2019) [1]. Solar generation peaks around the 12th hour of the day (standard time) and is highest during the spring/summer months and lowest during the winter months. These hourly capacity factors were multiplied by the total expected solar generation capacity in the 2040 most cost-effective No New Combustion portfolio presented in the PNM 2020 – 2040 IRP [1] to yield baseline solar power generation values at each hour of the year. For simplicity, the solar generation for a specific hour of any given month was assumed to be the same (e.g., the solar generation at 3 PM for each day in July was assumed to be the same). Uncertainty in these baseline values was accommodated by uniformly varying the baseline values by up to ±50% in the probabilistic simulations as summarized in Table 10. Although arbitrary, this uncertainty range was thought to be appropriate to accommodate uncertainty in not only the natural variability in solar generation but also the unceratinty in the preliminary climate models. A sensitivity was also performed to determine the impacts of varying the uncertainty range on LOLE.

5.1.3. Uncertainty in Battery Storage Resources

Table 11 shows the planned battery storage systems in PNM's No New Combustion portfolio. The total energy capacity (MWh) of each system was calculated as the product of the power capacity (MW) and storage duration of each system. The total energy storage capacity was used in the hourly energy balance calculations. Uncertainty in the battery storage capacity and performance was included by sampling the capacity fade and RTE for each annual realization using the uncertainty distributions in Table 10 and applying those to the conditions in Eq. (2).

TABLE 11. SUMMARY OF PLANNED BATTERY STORAGE SYSTEMS IN PNM'S NO NEW COMBUSTION, MOST COST-EFFECTIVE PORTFOLIO [1].

Storage System*	Nameplate Capacity (MW)		
	2021	2030	2040
Arroyo Storage ESA (MW)	0	150	150
Jicarilla Storage ESA (MW)	0	20	20
Rockmon Storage ESA (MW)	0	30	30
San Juan Storage ESA (MW)	0	100	100
New Lithium Ion Battery (4 hr) (MW)	0	508	1025
New Lithium Ion Battery (8 hr) (MW)	0	262	391
New Flow Battery (10 hr) (MW)	0	0	590
New Pumped Storage (MW)	0	0	0
Total storage capacity (MWh)	0	5328	14328

*ESA (Energy Storage Agreement) storage systems were assumed to be 4-hour Li-ion batteries for calculating energy capacity

5.1.4. Annual Energy Load

PNM provided the reference forecast for hourly electricity loads to Sandia. For each month, the loads at a particular hour of each day were averaged. Therefore, the hourly load for a particular time each day during a given month were assumed to be the same. For example, the load at 10 AM for each day in March was assumed to be the same. The loads in 2040 were approximately 6% higher than the reference loads in 2020.

5.2. Modeling Results

Results showed that the baseline LOLE (assuming 100% battery performance including 100% RTE and no capacity fade) was 0 days/year with the assumed generation resources, loads, and an assumed initial battery SOC (hour 1 of the year) of 100%.[1] The probabilistic simulations using uncertainty distributions summarized in Table 10 yielded a median LOLE of ~2 days/year and a 95th percentile of LOLE of ~8 days/year. A sensitivity study that reduced the uncertainty distribution for the wind and solar generation from +/- 50% to +/- 25% about the nominal climate-impacted value yielded a similar median LOLE of ~2 days/year and a 95th percentile of LOLE of ~7 days/year. Figure 4 shows the cumulative distribution functions of LOLE for the probabilistic simulations.

Figure 5 shows the results of a rank-regression analysis to determine the impact of uncertainties in the wind and solar resources and battery performance (RTE and capacity fade) on the LOLE using the +/- 50% uniform uncertainty distribution for wind and solar resources. Results show that the battery RTE was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. Figure 6 shows the incremental coefficients of determination for the uncertainty parameters. Uncertainty in the battery RTE yielded the greatest variability in the LOLE, followed by solar resource, wind resource, and battery fade. Similar results were obtained when a +/- 25% uncertainty distribution was assumed.

A sensitivity study was performed to determine how much battery storage capacity was required to reduce the LOLE to 0.2 days/year. In order to reduce the median (50th percentile) LOLE to 0.2 day/year, the battery storage capacity had to be increased from the baseline value of 14,328 MWh to ~25,000 – 30,000 MWh, about a factor of two higher than the baseline value assumed by PNM. In order to reduce the 95th percentile of LOLE to 0.2 day/year, the battery storage capacity had to be increased

[1] An initial SOC of 0% increased the LOLE to 0.33 days/year for the baseline case. An initial SOC of 10% resulted in an LOLE of 0.2 days/year.

© 2022 by ASME

to ~100,000 MWh, about a factor of seven times higher than the baseline value.

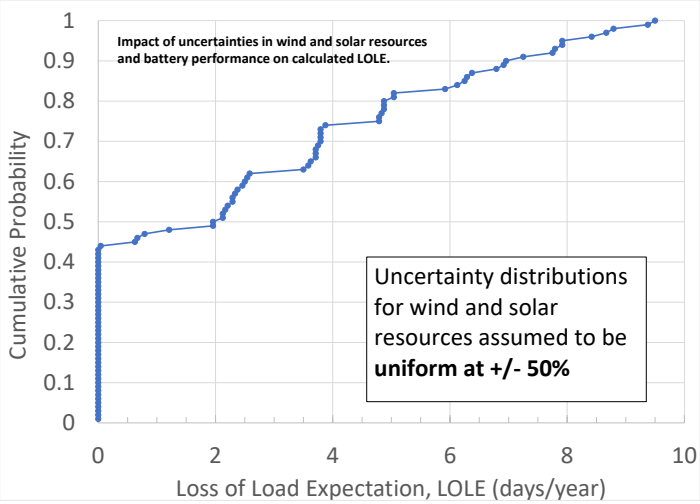


FIGURE 4. CUMULATIVE PROBABILITY OF LOSS OF LOAD EXPECTATION (LOLE) WITH INCLUSION OF SOLAR AND WIND RESOURCE UNCERTAINTY RESULTING FROM CLIMATE CHANGE AND UNCERTAINTY IN BATTERY PERFORMANCE. UNIFORM DISTRIBUTIONS OF ±50% WERE ASSUMED FOR THE SOLAR, WIND, AND BATTERY PERFORMANCE UNCERTAINTY DISTRIBUTIONS.

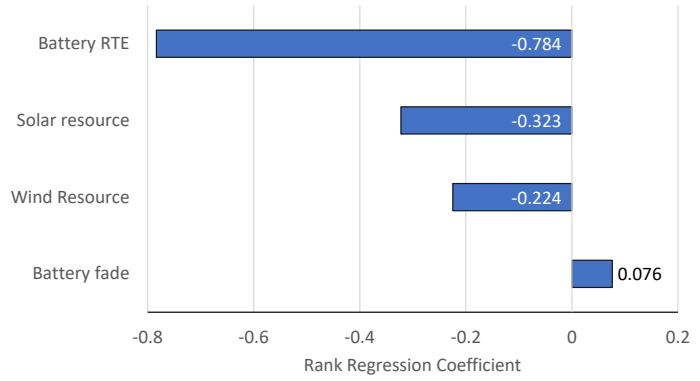


FIGURE 5. IMPACT OF UNCERTAINTIES IN SOLAR AND WIND RESOURCES AND BATTERY PERFORMANCE RESULTING FROM CLIMATE CHANGE ON LOLE. STANDARDIZED RANK REGRESSION COEFFICIENTS ARE SHOWN.

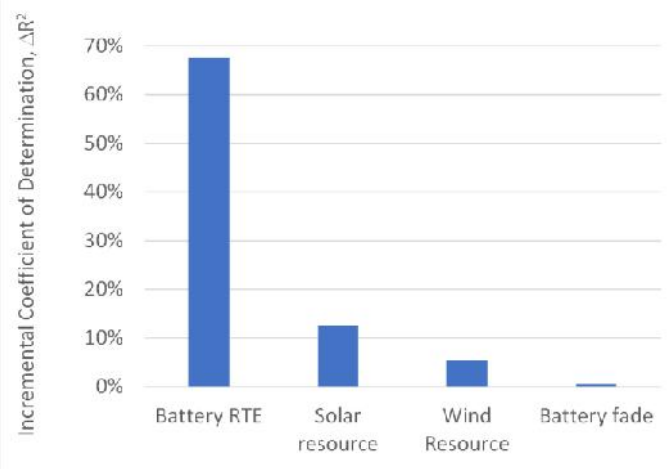


FIGURE 6. IMPACT OF UNCERTAINTIES IN SOLAR AND WIND RESOURCES AND BATTERY PERFORMANCE RESULTING FROM CLIMATE CHANGE ON LOLE VARIABILITY. INCREMENTAL COEFFICIENTS OF DETERMINATION ARE SHOWN.

6. CONCLUSION AND RECOMMENDATIONS

New Mexico's Energy Transition Act (ETA) requires power utilities in New Mexico to increase their share of carbon-free electricity generation to 50% by 2030, 80% by 2040, and 100% by 2045. According to its 2020 Integrated Resource Plan, PNM's plan is to rely heavily on utility-scale PV and wind generation with battery energy storage to meet these requirements in the most cost-effective portfolio with no new combustion. The objective of this work was to develop a methodology to evaluate the potential impacts of climate change on wind and solar resources, as well as uncertainties in battery performance, on the annual LOLE.

Results for the extreme climate-change scenario show that the projected wind power may decrease by ~13% due to projected decreases in wind speed. Projected solar power may decrease by ~4% due to decreases in irradiance and increases in temperature in NM. Uncertainty in these climate-induced changes in wind and solar resources was accommodated in probabilistic models assuming uniform distributions in the annual reductions in solar and wind resources. Uncertainty in battery storage performance was also evaluated based on increased temperature, capacity fade, and degradation in round-trip efficiency. The hourly energy balance was determined throughout the year given uncertainties in the renewable energy resources and energy storage. The loss of load expectation (LOLE) was evaluated for the 2040 No New Combustion portfolio and found to increase from 0 days/year to a median value of ~2 days/year due to potential reductions in renewable energy resources and battery storage performance and capacity. A rank-regression analyses revealed that battery round-trip efficiency was the most significant parameter that impacted LOLE, followed by solar resource, wind resource, and battery fade. An increase in battery storage capacity to ~30,000 MWh from a baseline value of ~14,000 MWh was required to reduce

© 2022 by ASME

the median value of LOLE to ~0.2 days/year with consideration of potential climate impacts and battery degradation.

ACKNOWLEDGMENTS

The authors thank Nick Phillips from PNM for providing data and consultation regarding this work. This work was funded by the Climate Change Security Center program (278/40.02.01.04.02.01.06) at Sandia National Laboratories (Center 8900).

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Sandia National Laboratories is a multimission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC., a wholly owned subsidiary of Honeywell International, Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA0003525. SAND2022-4610 C

REFERENCES

[1] Phillips, N., M. Reiman, D. Brunton, S. Gutierrez, and J. Heslop, 2021, PNM 2020 - 2040 Integrated Resource Plan, Public Service Company of New Mexico, Albuquerque, NM. January 29, 2021 https://www.pnmforwardtogether.com/irp.

[2] Burrows, S.M., M. Maltrud, X. Yang, Q. Zhu, N. Jeffery, X. Shi, D. Ricciuto, S. Wang, G. Bisht, J. Tang, J. Wolfe, B.E. Harrop, B. Singh, L. Brent, S. Baldwin, T. Zhou, P. Cameron-Smith, N. Keen, N. Collier, M. Xu, E.C. Hunke, S.M. Elliott, A.K. Turner, H. Li, H. Wang, J.-C. Golaz, B. Bond-Lamberty, F.M. Hoffman, W.J. Riley, P.E. Thornton, K. Calvin, and L.R. Leung, 2020, The DOE E3SM v1.1 Biogeochemistry Configuration: Description and Simulated Ecosystem-Climate Responses to Historical Changes in Forcing, *Journal of Advances in Modeling Earth Systems*, **12**(9), p. e2019MS001766.

[3] Eyring, V., S. Bony, G.A. Meehl, C.A. Senior, B. Stevens, R.J. Stouffer, and K.E. Taylor, 2016, Overview of the Coupled Model Intercomparison Project Phase 6 (CMIP6) experimental design and organization, *Geosci. Model Dev.*, **9**(5), p. 1937-1958.

[4] Golaz, J.-C., P.M. Caldwell, L.P.V. Roekel, M.R. Petersen, Q. Tang, J.D. Wolfe, G. Abeshu, V. Anantharaj, X.S. Asay-Davis, D.C. Bader, S.A. Baldwin, G. Bisht, P.A. Bogenschutz, M. Branstetter, M.A. Brunke, S.R. Brus, S.M. Burrows, P.J. Cameron-Smith, A.S. Donahue, M. Deakin, R.C. Easter, K.J. Evans, Y. Feng, M. Flanner, J.G. Foucar, J.G. Fyke, B.M. Griffin, C. Hannay, B.E. Harrop, M.J. Hoffman, E.C. Hunke, R.L. Jacob, D.W. Jacobsen, N. Jeffery, P.W. Jones, N.D. Keen, S.A. Klein, V.E. Larson, L.R. Leung, H.-Y. Li, W. Lin, W.H. Lipscomb, P.-L. Ma, S. Mahajan, M.E. Maltrud, A. Mametjanov, J.L. McClean, R.B. McCoy, R.B. Neale, S.F. Price, Y. Qian, P.J. Rasch, J.E.J.R. Eyre, W.J. Riley, T.D. Ringler, A.F. Roberts, E.L. Roesler, A.G. Salinger, Z. Shaheen, X. Shi, B. Singh, J. Tang, M.A. Taylor, P.E. Thornton, A.K. Turner, M. Veneziani, H. Wan, H. Wang, S. Wang, D.N. Williams, P.J. Wolfram, P.H. Worley, S. Xie, Y. Yang, J.-H. Yoon, M.D. Zelinka, C.S. Zender, X. Zeng, C. Zhang, K. Zhang, Y. Zhang, X. Zheng, T. Zhou, and Q. Zhu, 2019, The DOE E3SM Coupled Model Version 1: Overview and Evaluation at Standard Resolution, *Journal of Advances in Modeling Earth Systems*, **11**(7), p. 2089-2129.

[5] Tebaldi, C., K. Debeire, V. Eyring, E. Fischer, J. Fyfe, P. Friedlingstein, R. Knutti, J. Lowe, B. O'Neill, B. Sanderson, D. van Vuuren, K. Riahi, M. Meinshausen, Z. Nicholls, K.B. Tokarska, G. Hurtt, E. Kriegler, J.-F. Lamarque, G. Meehl, R. Moss, S.E. Bauer, O. Boucher, V. Brovkin, Y.-H. Byun, M. Dix, S. Gualdi, H. Guo, J.G. John, S. Kharin, Y. Kim, T. Koshiro, L. Ma, D. Olivié, S. Panickal, F. Qiao, X. Rong, N. Rosenbloom, M. Schupfner, R. Séférian, A. Sellar, T. Semmler, X. Shi, Z. Song, C. Steger, R. Stouffer, N. Swart, K. Tachiiri, Q. Tang, H. Tatebe, A. Voldoire, E. Volodin, K. Wyser, X. Xin, S. Yang, Y. Yu, and T. Ziehn, 2021, Climate model projections from the Scenario Model Intercomparison Project (ScenarioMIP) of CMIP6, *Earth System Dynamics*, **12**(1), p. 253-293.

[6] Solaun, K. and E. Cerdá, 2019, Climate change impacts on renewable energy generation. A review of quantitative projections, *Renewable and Sustainable Energy Reviews*, **116**, p. 109415.

[7] Craig, M.T., S. Cohen, J. Macknick, C. Draxl, O.J. Guerra, M. Sengupta, S.E. Haupt, B.-M. Hodge, and C. Brancucci, 2018, A review of the potential impacts of climate change on bulk power system planning and operations in the United States, *Renewable and Sustainable Energy Reviews*, **98**, p. 255-267.

[8] Craig, M.T., I.L. Carreño, M. Rossol, B.-M. Hodge, and C. Brancucci, 2019, Effects on power system operations of potential changes in wind and solar generation potential under climate change, *Environmental Research Letters*, **14**(3), p. 034014.

[9] Losada Carreño, I., M.T. Craig, M. Rossol, M. Ashfaq, F. Batibeniz, S.E. Haupt, C. Draxl, B.-M. Hodge, and C. Brancucci, 2020, Potential impacts of climate change on wind and solar electricity generation in Texas, *Climatic Change*, **163**(2), p. 745-766.

[10] Haupt, S.E., J. Copeland, W.Y.Y. Cheng, Y. Zhang, C. Ammann, and P. Sullivan, 2016, A Method to Assess the

© 2022 by ASME

Wind and Solar Resource and to Quantify Interannual Variability over the United States under Current and Projected Future Climate, *Journal of Applied Meteorology and Climatology*, **55**(2), p. 345-363.

[11] Mearns, L., S. McGinnis, D. Korytina, R. Arritt, S. Biner, M. Bukovsky, H.-I. Chang, O. Christensen, D. Herzmann, Y. Jiao, S. Kharin, M. Lazare, G. Nikulin, M. Qian, J. Scinocca, K. Winger, C. Castro, A. Frigon, and W. Gutowski, *The NA-CORDEX dataset*, 2017, UCAR/NCAR.

[12] Skamarock, W., J. Klemp, J. Dudhia, D. Gill, D. Barker, W. Wang, X.-Y. Huang, and M. Duda, 2008, A Description of the Advanced Research WRF Version 3, UCAR/NCAR, 1002 KB 2008-06

[13] Chen, L., 2020, Impacts of climate change on wind resources over North America based on NA-CORDEX, *Renewable Energy*, **153**, p. 1428-1438.

[14] Pryor, S.C., R.J. Barthelmie, M.S. Bukovsky, L.R. Leung, and K. Sakaguchi, 2020, Climate change impacts on wind power generation, *Nature Reviews Earth & Environment*, **1**(12), p. 627-643.

[15] Crook, J.A., L.A. Jones, P.M. Forster, and R. Crook, 2011, Climate change impacts on future photovoltaic and concentrated solar power energy output, *Energy & Environmental Science*, **4**(9), p. 3101-3109.

[16] Folini, D., T.N. Dallafior, M.Z. Hakuba, and M. Wild, 2017, Trends of surface solar radiation in unforced CMIP5 simulations, *Journal of Geophysical Research: Atmospheres*, **122**(1), p. 469-484.

[17] Haupt, S.E., B. Kosović, T. Jensen, J.K. Lazo, J.A. Lee, P.A. Jiménez, J. Cowie, G. Wiener, T.C. McCandless, M. Rogers, S. Miller, M. Sengupta, Y. Xie, L. Hinkelman, P. Kalb, and J. Heiser, 2018, Building the Sun4Cast System: Improvements in Solar Power Forecasting, *Bulletin of the American Meteorological Society*, **99**(1), p. 121-136.

[18] Huber, I., L. Bugliaro, M. Ponater, H. Garny, C. Emde, and B. Mayer, 2016, Do climate models project changes in solar resources?, *Solar Energy*, **129**, p. 65-84.

[19] Chen, L., 2021, Uncertainties in solar radiation assessment in the United States using climate models, *Climate Dynamics*, **56**(1), p. 665-678.

[20] Jackson, N.D. and T. Gunda, 2021, Evaluation of extreme weather impacts on utility-scale photovoltaic plant performance in the United States, *Applied Energy*, **302**, p. 117508.

[21] Jiménez, P.A., S. Alessandrini, S.E. Haupt, A. Deng, B. Kosovic, J.A. Lee, and L.D. Monache, 2016, The Role of Unresolved Clouds on Short-Range Global Horizontal Irradiance Predictability, *Monthly Weather Review*, **144**(9), p. 3099-3107.

[22] Wang, M., P. Ullrich, and D. Millstein, 2020, Future projections of wind patterns in California with the variable-resolution CESM: a clustering analysis approach, *Climate Dynamics*, **54**(3), p. 2511-2531.

[23] Millstein, D., J. Solomon-Culp, M. Wang, P. Ullrich, and C. Collier, 2019, Wind energy variability and links to regional and synoptic scale weather, *Climate Dynamics*, **52**(7), p. 4891-4906.

[24] National Renewable Energy Laboratory. *Wind Prospector*. [Accessed 2021]; Available from: https://maps.nrel.gov/wind-prospector.

[25] International Electrotechnical Commission, 2005, Wind turbines - Part 1: Design requirements, IEC 61400-1:2005, https://webstore.iec.ch/publication/5426.

[26] Kalmikov, A., K. Dykes, and K. Araujo, Wind Power Fundamentals, MIT, https://web.mit.edu/windenergy/windweek/Presentations/Wind%20Energy%20101.pdf.

[27] King, J., A. Clifton, and B.M. Hodge, 2014, Validation of Power Output for the WIND Toolkit, National Renewable Energy Laboratory, NREL/TP-5D00-61714, Golden, CO. https://www.nrel.gov/docs/fy14osti/61714.pdf.

[28] Holmgren, W.F., C.W. Hansen, and M.A. Mikofski, 2018, pvlib python: a python package for modeling solar energy systems, *The Journal of Open Source Software*, **3**(29).

[29] Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby, 2018, The National Solar Radiation Data Base (NSRDB), *Renewable and Sustainable Energy Reviews*, **89**, p. 51-60.

[30] Preger, Y., H.M. Barkholtz, A. Fresquez, D.L. Campbell, B.W. Juba, J. Romàn-Kustas, S.R. Ferreira, and B. Chalamala, 2020, Degradation of Commercial Lithium-Ion Cells as a Function of Chemistry and Cycling Conditions, *Journal of The Electrochemical Society*, **167**(12), p. 120532.

[31] Spotnitz, R., 2003, Simulation of capacity fade in lithium-ion batteries, *Journal of Power Sources*, **113**(1), p. 72-80.

© 2022 by ASME

Welcome!

Stakeholder Engagement Meeting
(Meeting #5)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, June 15
9:00 – 10:30 AM Mountain Daylight Time

Materials available at: New Mexico Energy Planning – Gridworks

or

https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose of Today's Meeting

- Our primary objective is to incorporate stakeholder input through the two work products (Statement of Need and Action Plan)
- Specific Outcomes
  - Prepare stakeholders to determine level of consensus regarding Statement of Need input during June 29 meeting
  - Briefing on PNM modeling results to date
  - Update on stakeholder requested "additional" modeling runs

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Stakeholder Engagement is Advancing Toward Action Plan Input

March – May	June – August	Sept – Nov

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

New stakeholders, if this is your first meeting with this group
Please type into the chat:

- Name
- Organization
- Your primary interest pertaining to the IRP

Clarification from NM PRC, Issued June 2

NM PRC Additional Guidance

Action Plan

- 3-year period following filing: 2024-2026

Statement of Need

- Planning period minimum is 20 years and can be longer; determined by utility in consultation with stakeholders

Investor-Owned-Electric-Utilities-and-Stakeholder-June-2-2023.pdf (gridworks.org)

New Process for Stakeholder Questions and Data Requests

1. Stakeholders email questions or information requests to team captains for prioritization, copy to mtatro@gridworks.org
2. Captains submit questions that are germane to working group activities to PNM
3. PNM enters questions and responses into Q&A database, link TBD
4. Gridworks posts “rolling response” summary document to www.gridworks.org website prior to each stakeholder meeting

Statement of Need Draft Update

- Review of SoN draft by volunteer group
  - Team captain: Michael Barrio, Advanced Energy United
- Discussion
- Next steps:
  - Redline comments on Word version or direct comments on GOOGLE DOC by June 20
  - Working group incorporates feedback and provides complete document for posting on website by June 23.
  - Discuss stakeholder consensus during June 29 in-person workshop

Modeling Results Update

PNM TEAM

GRIDWORKS

Modeling Core Team Update on Additional Stakeholder Requested Modeling Runs

Team captains:

- **Aaron Gould, WRA**
- **Rachel Wilson, Form Energy**
- **Nick Phillips, PNM**

Future CTP with high EV & High Building Electrification
Future CTP with increased DR
Extensions for Valencia and/or Reeves
FCPP through 2027/2031
No combustion scenario post 2039 - Include: Solar, Wind, Li-ion storage, Long duration storage, wind expansion, geothermal as candidate options
No New Combustion with Thermal Storage
Accelerated Carbon Free (2030, 2035)
Complex Scenario – Transmission Expansion + Many Alternative Resources
Gas Price (High/Very High)
More Extreme Weather Sensitivities
WRAP / RTO modeling
Correlated Gas Outages

A Look Ahead as We Prepare for Input to the Action Plan

March – May	June – August	Sept – Nov

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

NEXT DEADLINES

TODAY - requests for access to modeling information (public or confidential)

DATE TBD - Requests by stakeholders who wish to share their own modeling results on July 13 or Aug. 17

SCHEDULED MEETINGS

- June 29 – Full day focused on: SoN consensus; modeling results (by PNM and others); and candidate action plan suggestions. Discuss need for additional SERVM runs.
- July 13 – Results of prioritized stakeholder requested runs. Discuss and improve action plan input. Decide on additional SERVM runs, if necessary.
- Aug. 17 – Review results of additional modeling runs. Refine input to action plan.

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

PNM 2023-2042 IRP: Initial Modeling Results

FACILITATED STAKEHOLDER MEETING #5

JUNE 15, 2023

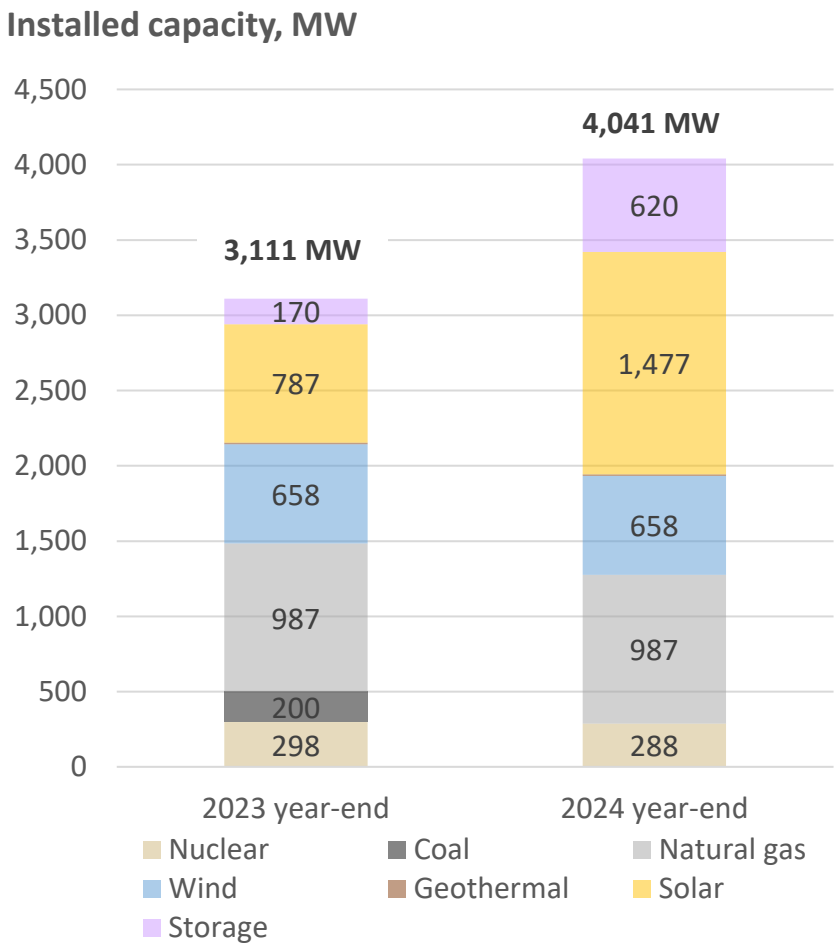


DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

PNM'S EXISTING RESOURCE PORTFOLIO AND NEAR-TERM RESOURCE ADEQUACY



2024 capacity

Storage: 620

Solar: 1,477

Wind: 658

Natural Gas: 987

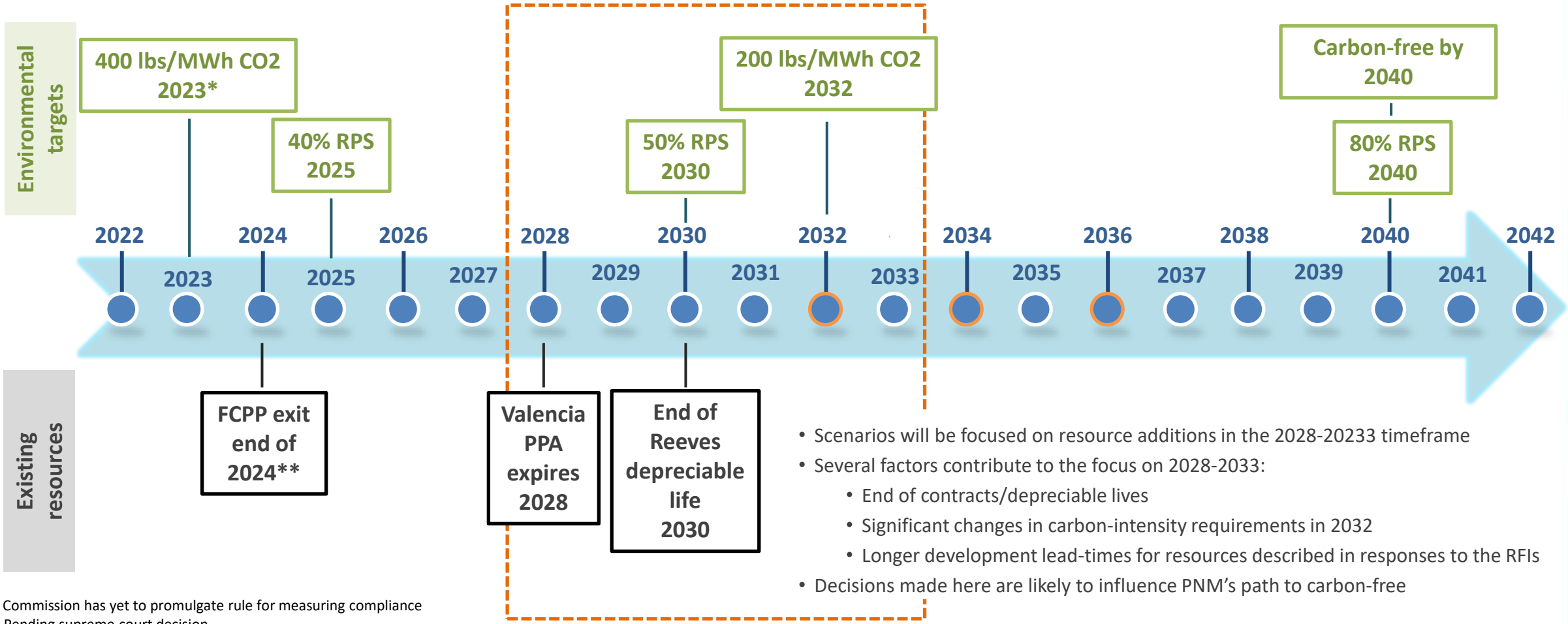
Coal: 0 MW (FCPP abandoned*)

Nuclear: 288 MW share of Palo Verde

*Pending appeal at NM Supreme Court

- Near term additions include 400 MW of solar and 170 MW of storage by the end of 2023
- By year-end 2024, PNM will have added an additional 690 MW of solar and 450 MW of storage
- RFPs for 2026-2028 are currently ongoing

KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS POINT TO 2028-2033 AS A CRITICAL PERIOD



- Scenarios will be focused on resource additions in the 2028-20233 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs
- Decisions made here are likely to influence PNM's path to carbon-free

* Commission has yet to promulgate rule for measuring compliance
** Pending supreme court decision

TECHNOLOGIES FOR PHASE 1 MODELING

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



Energy efficiency and demand response included in all scenarios

PNM Talk to us. PNM.com

DISCLAIMER - RESULTS ARE PRELIMINARY DRAFT

- PNM has incorporated numerous updates to its modeling in this IRP cycle
- While we have taken every effort to ensure the validity of these techniques, please understand that the results we will discuss are considered preliminary draft results and will likely change as we continue to refine the analysis
- In previous IRP cycles we would not present results before a full draft of the IRP was ready; we have made efforts to get stakeholders involved earlier in this IRP cycle, starting the public advisory process earlier than ever
- In order to maximize stakeholder involvement, presenting preliminary results and inviting feedback earlier is equally important
- At this stage, we will highlight some of the key trends we see so far, and some of the areas that require further study and refinement

Preliminary results

PHASE 1 SCENARIOS EXPLORE ATTRIBUTES OF A VARIETY OF TECHNOLOGIES

Scenario Name	Scenario-Specific Assumptions
Base technologies	Only solar, storage, and EE, DR allowed through 2032
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 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 hydrogen-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
H2 - 250 MW	~250 MW hydrogen-fueled CT & ~750 MW electrolyzer added in 2031

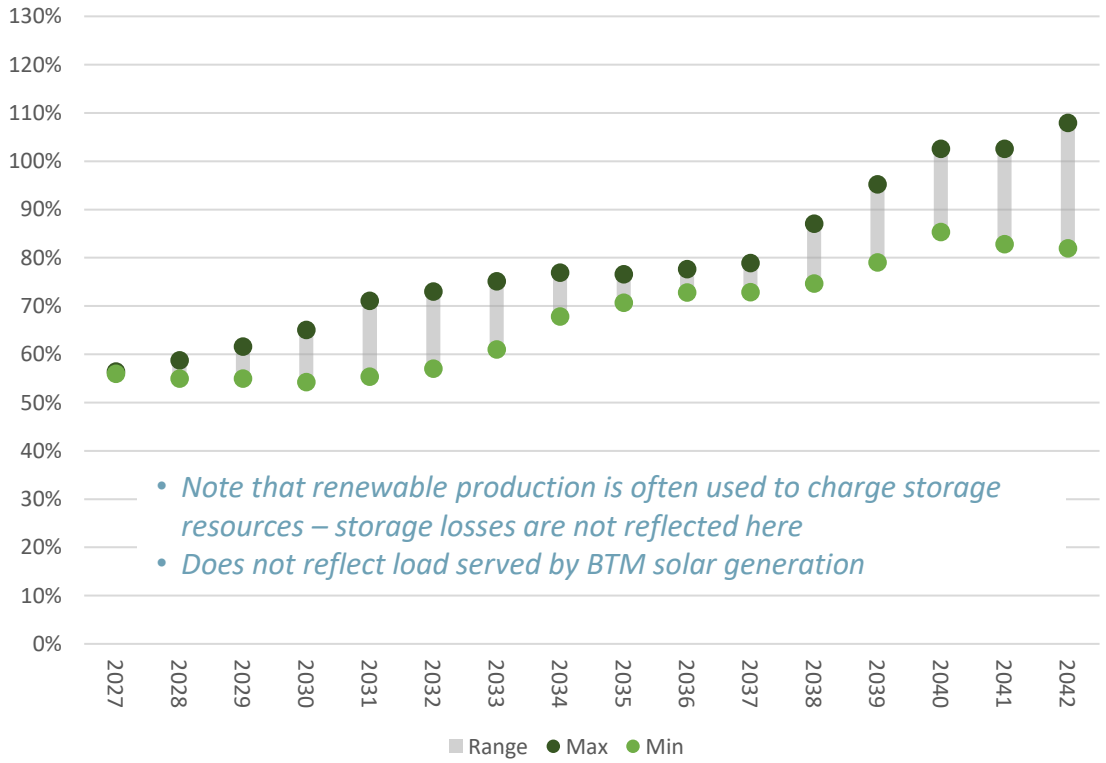
- In Phase 1, technology-specific scenarios are screened under the Current Trends and Policy future for capacity expansion and production cost runs
- This approach gives PNM the ability to evaluate the overall portfolio costs associated with a range of scenarios
- Results presented today include:
  - Portfolio-level carbon intensity
  - Present value revenue requirement
  - New capacity additions through 2032/2042
- All portfolios required to meet reliability, RPS, and carbon-intensity targets

Preliminary results

PNM Talk to us. PNM.com

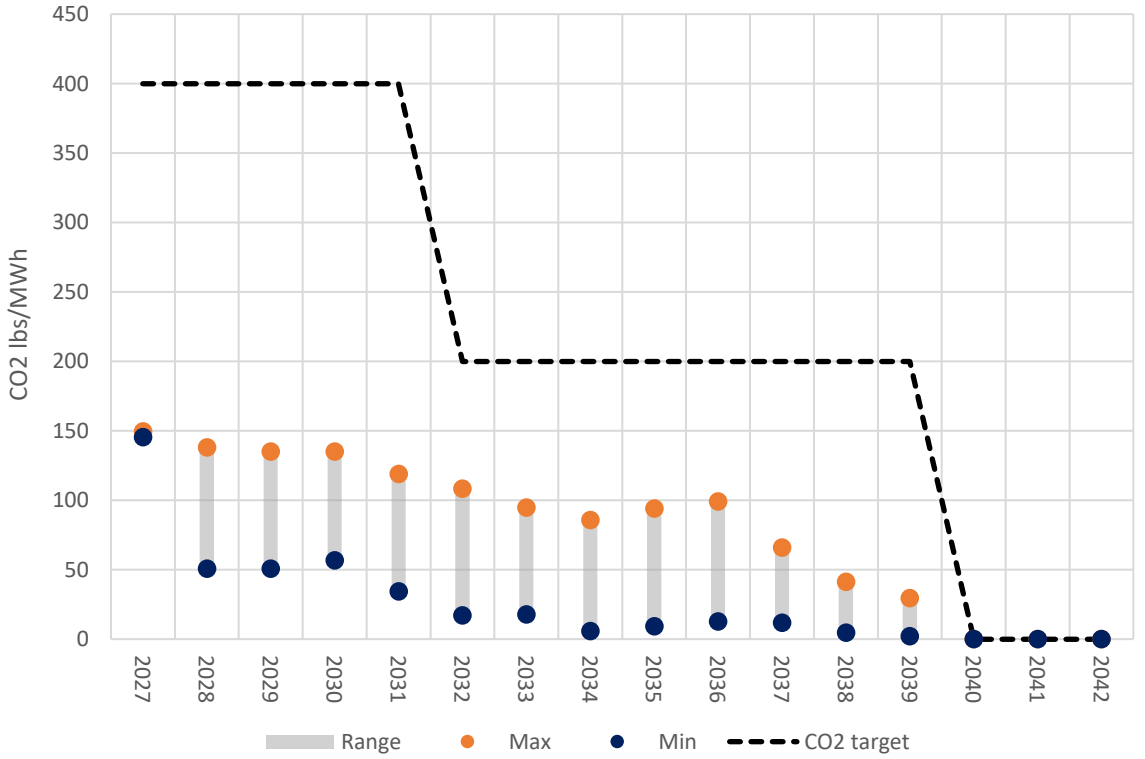
ALL PORTFOLIOS MEET ENVIRONMENTAL REQUIREMENTS

Renewable production as % of retail load across portfolios



- *Note that renewable production is often used to charge storage resources – storage losses are not reflected here*
- *Does not reflect load served by BTM solar generation*

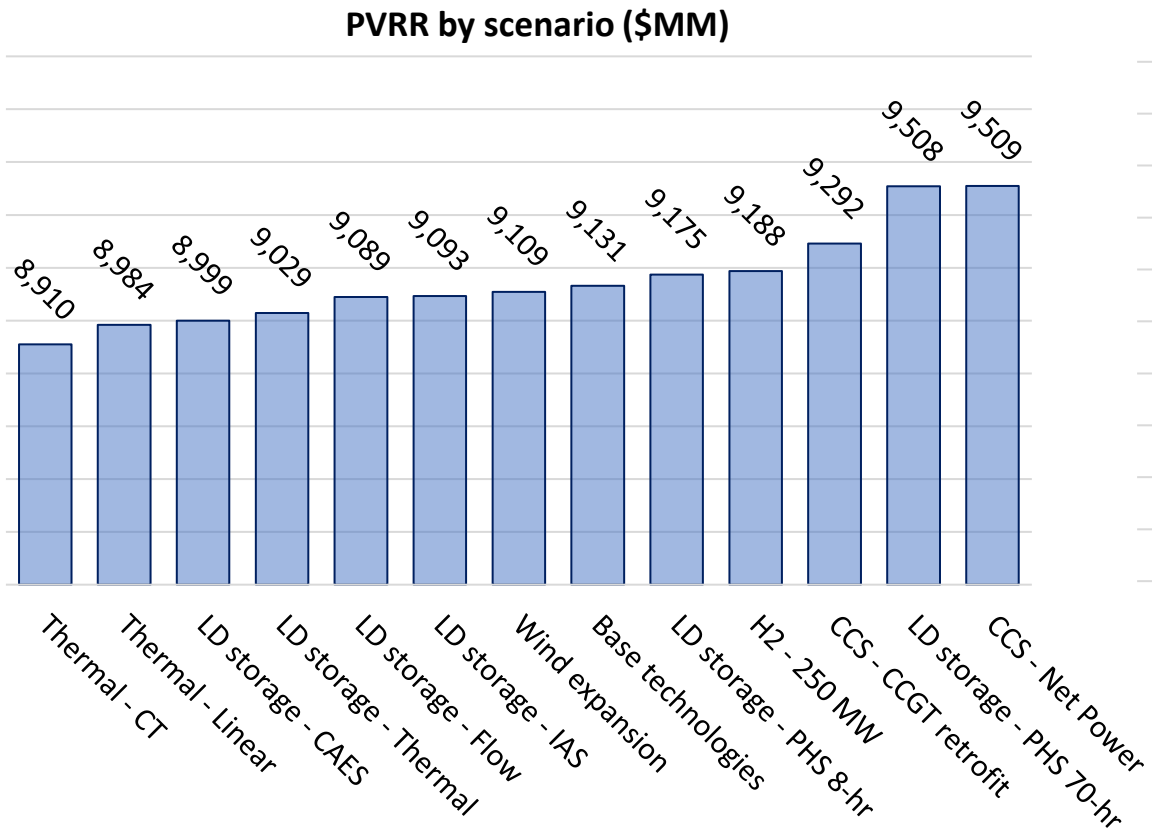
Carbon intensity across portfolios

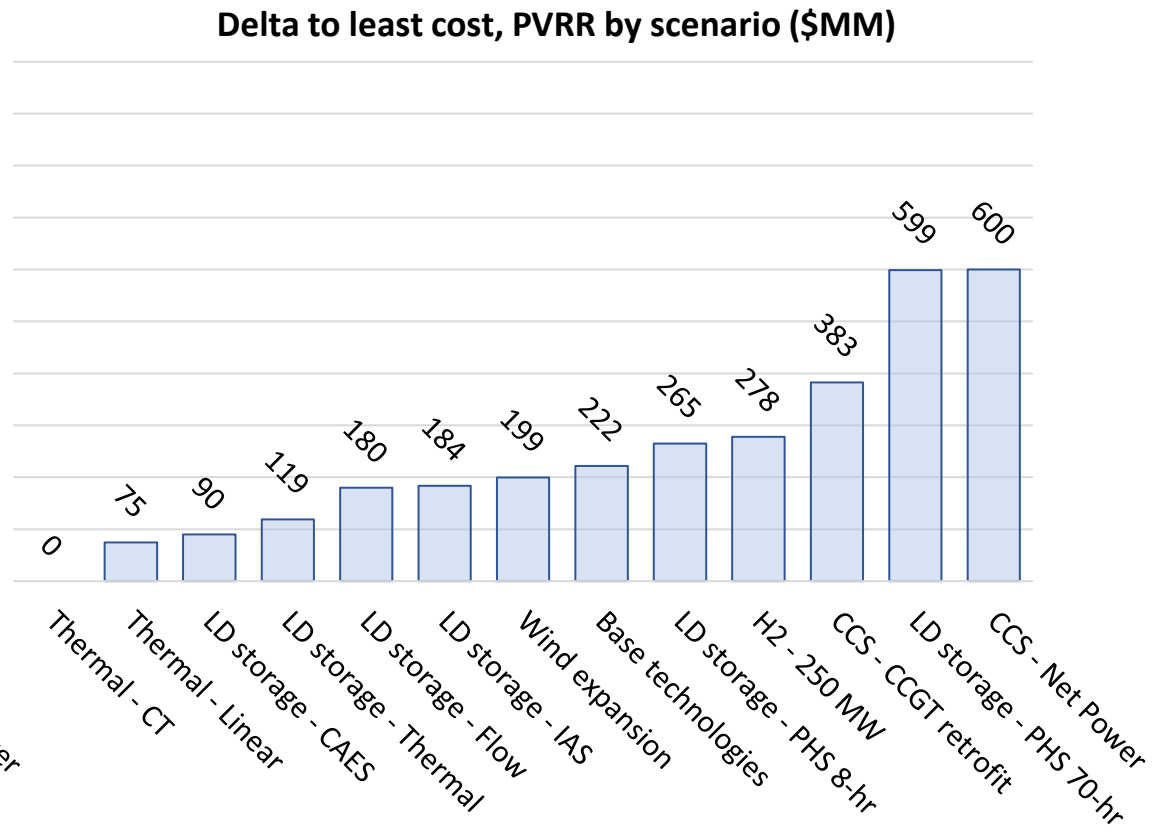


Preliminary results

Talk to us.

COST COMPARISON ACROSS SCENARIOS





Preliminary results

NEW RESOURCE ADDITIONS BY 2032 (GENERIC/RFI ADDITIONS 2025-2032, DOES NOT REFLECT RETIREMENTS)

Scenario	PVRR rank	Solar	Wind	Energy Efficiency	Demand response	Battery Storage	Pumped Storage	Long-Duration Storage	Electrolyzer	CTs	Linear generator	CCS Retrofits	NET power plant
Thermal - CT	1	193	-	152	42	684	-	-	-	164	-	-	-
Thermal - Linear	2	251	-	157	63	801	-	-	-	-	50	-	-
LD storage - CAES	3	318	-	153	42	747	-	200	-	-	-	-	-
LD storage - Thermal	4	221	-	155	63	658	-	150	-	-	-	-	-
LD storage - Flow	5	314	-	160	63	703	-	100	-	-	-	-	-
LD storage - IAS	6	191	-	154	63	753	-	100	-	-	-	-	-
Wind expansion	7	-	800	155	63	771	-	-	-	-	-	-	-
Base technologies	8	294	-	162	63	857	-	-	-	-	-	-	-
LD storage - PHS 8-hr	9	72	-	147	63	662	300	-	-	-	-	-	-
H2 - 250 MW	10	855	-	151	42	688	-	-	768	256	-	-	-
CCS - CCGT retrofit	11	338	-	161	63	945	-	-	-	-	-	196	-
LD storage - PHS 70-hr	12	249	-	149	63	435	300	-	-	-	-	-	-
CCS - Net Power	13	173	-	157	42	686	-	-	-	-	-	-	280

Preliminary results

NEW RESOURCE ADDITIONS BY 2042 (GENERIC/RFI ADDITIONS 2025-2042, DOES NOT REFLECT RETIREMENTS)

Scenario	PVRR rank	Solar	Wind	Energy Efficiency	Demand response	Battery Storage	Pumped Storage	Long-Duration Storage	Electrolyzer	CTs	Linear generator	CCS Retrofits	NET power plant
Thermal - CT	1	1,190	1,000	304	42	1,603	-	-	-	328	-	-	-
Thermal - Linear	2	1,429	1,000	308	63	2,181	-	-	-	-	50	-	-
LD storage - CAES	3	1,465	1,000	304	42	2,170	-	200	-	-	-	-	-
LD storage - Thermal	4	1,460	1,000	307	63	2,231	-	150	-	-	-	-	-
LD storage - Flow	5	2,097	800	314	63	2,284	-	100	-	-	-	-	-
LD storage - IAS	6	1,495	1,000	308	63	2,385	-	100	-	-	-	-	-
Wind expansion	7	1,528	1,000	309	63	2,603	-	-	-	-	-	-	-
Base technologies	8	2,095	800	316	63	2,542	-	-	-	-	-	-	-
LD storage - PHS 8-hr	9	1,473	1,000	298	63	1,836	300	-	-	-	-	-	-
H2 - 250 MW	10	4,516	-	303	42	3,716	-	-	768	256	-	-	-
CCS - CCGT retrofit	11	1,213	1,000	312	63	2,201	-	-	-	-	-	196	-
LD storage - PHS 70-hr	12	1,770	1,000	301	63	1,759	300	-	-	-	-	-	-
CCS - Net Power	13	1,470	1,000	304	42	2,328	-	-	-	-	-	-	280

Preliminary results

PNM Talk to us. PNM.com

AREAS OF FOCUS FOR ADDITIONAL STUDY

- The Inflation Reduction Act (IRA) is a significant and complex piece of legislation that provides significant tax credits for investment in and production from a wide range of clean energy technologies
- Given the complexity of the IRA and lack of detailed guidance on all aspects, we are modeling the impacts given our current understanding – which will evolve as we continue to learn and better understand the IRA
- We continue to assess PTC interactions and implications for our modeling
- We continue to evaluate results and review our modeling approaches regarding RFI technologies and hydrogen
- We will use our initial results and findings to better inform next phase analysis

Preliminary results

PNM'S INITIAL OBSERVATIONS & NEXT STEPS

Initial Observations

- Due to favorable economics enabled by the IRA and diversity with solar, wind appears cost-effective across all portfolios; to the extent we can develop transmission, it may play a role in meeting near-term needs
- Solar and storage will play a key role in meeting our future needs, but meeting near-term needs with solar and storage exclusively is costly – we want to ensure we're taking steps to make other options available
- Multiple longer duration storage technologies can serve as viable solutions to meet reliability needs in the early 2030s and merit further investigation
- Thermal technologies provide cost savings and are a proven option – and we can add capacity without materially impacting any of our environmental objectives
- While natural gas scenarios are some of the lowest-cost, they hinge on the existence of a hydrogen economy by 2040 – further exploration of alternative options for these resources, should we invest in them, is needed
- Large tax credits for hydrogen production infrastructure and renewable production appear to provide some benefits to the hydrogen scenario; however, this is a very complex scenario, and warrants continued evaluation of IRA rules and technology advancements

Next Steps

- Examine how robust initial observations are to key uncertainties
- Explore implications of technology cost uncertainty upon results that rely heavily on emerging technologies
- Determine the cost to add additional wind/solar/battery storage capacity by 2040 should a hydrogen economy fail to materialize
- Construct hybrid scenarios that combine most attractive options identified in initial scenario analysis; Phase 2 modeling will inform us about synergies between technologies
- Conduct additional reliability modeling of most promising portfolio options

Preliminary results

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



Integrated Resource Plan:
Statement of Need Table of Contents
Working group suggestions for Public Service New Mexico - May 31, 2023

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction
    a. The PNM Integrated Resource Plan 2023 provides a comprehensive long range path for building out the strongest, most reliable electrical power delivery system for our customers over the next 20 years as we can envision. The IRP report begins with the current status of PNM's system, and shows how available resources and technologies can bring improvements. Simultaneously we recognize that changes are occurring in nearly every sector of the environment in which we operate. These will require ongoing re-evaluation and modifications to the 2023 IRP plan that will be incorporated in future triennial PNM IRPs.

    Meeting our clean energy goals and preserving system reliability, while providing for the growing needs of our customers in an affordable manner, will require the addition of significant amounts of new generation capacity over the next twenty years. We anticipate that between today and 2040, the likely amount of new installed generation capacity will total between 4,000 to 5,000 MW or more. This amount of *new* capacity is significantly greater than the amount that exists today, implying that the achievement of our goals will require continuous and significant evolution of our portfolio.

2. Vision and Goals
    a. The identification of a set of resources and a sequencing of those resource deployments that conforms to the regulations and policies of the State of New Mexico, reliably serves all customers at a reasonable cost with electrical energy that is that is resilient in the face of national security, technology, infrastructure, resource, cyber and environmental constraints.
    b. Regulatory Environment and Requirements
        i. Legal requirements and standards in planning horizon
            1. Energy Transition Act
                a. Renewable Energy Act / Renewable Portfolio Standard
                    i. 80% renewable by 2040 and 100% carbon-free by 2045
                b. Status of plant abandonment and replacement power
            2. Efficient Use of Energy Act
                a. Energy efficiency and load management goals starting in 2025/6

3. EPA GHG Standards for fossil-fueld power plants
    a. Proposed 5/23/23, may take 1 year or longer to finalize
    b. Starting in 2030, the proposed requirements vary by the type of unit (new or existing, combustion turbine or utility boiler, coal-fired or natural gas-fired), how frequently it operates, and its operating horizon (i.e., planned operation after certain future dates).
4. EPA Good Neighbor Plan
    a. NOx emissions trading regime for power plants in 22 states
    b. March 15, 2023 plan did not include New Mexico but said "EPA's updated modeling analysis for 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico, may be significantly contributing to nonattainment or maintenance in downwind sites. EPA intends to undertake additional assessment of its modeling for these states and will determine if it is necessary to address Good Neighbor obligations for these states in future action(s)."
    c.

ii. Known and expected rules
1. NM Stat § 62-17-10 (2018)
2. NM Administrative Code 17.7.3
3. Case #21-00128-UT Final Order
    a. Substantial revisions to NMAC 17.7.3 IRP planning rule, of which this Statement of Need is a part.
        i. IRP filing and content requirements
        ii. description of existing resources,(2) current load forecast, (3) load and resources table, (4) identification of resource options, (5) statement of need, (6) determination of the resource portfolio, and (7) action plan,
        iii. Facilitated Stakeholder Process; IRP Process
        iv. Statement of Need
        v. Action Plan
            1. June 2 PRC letter re: Action Plan period and planning horizon
        vi. Request for Proposals Process, Cost recovery, Independent Monitor, Variances and Amendments
4. Case #21-00033-UT(PNM 2021 IRP) Final Order
    a. "23. For this reason, the Commission finds that PNM should include, in its future 2023 IRP filing a meaningful analysis of transmission and distribution constraints and opportunities to increase resource availability and flexibility."
    b. Additional requirements/orders added since #21-00128-UT Final Order?

c. Goals
i. Reliability and Resiliency: Utility's Obligation to Serve
1. Minimum Reserve Requirements
2. Reliability Standards
3. Swift recovery from climate or cyber disruption
ii. Public Interest and Equity

1. Responsibilities to Ratepayers and Shareholders
    a. Affordability
    b. Availability to Underserved Communities
    c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
2. Costs associated with the development and deployment of all candidate resources
    a. Costs of Energy to Consumers
    b. Climate Change Impacts
    c. End of Life (Recycling/disposal)
3. Consumer Education
4. NIMBY

3. Current and Expected System Conditions
    a. Timeline
        i. Urgency (What is driving the urgency?)
    b. Load Forecast
        i. Electrification Impact
    c. Baseline System
        i. Forecasted Retirements
        ii. Transmission Constraints
        iii. Distribution System Constraints
4. Identified Decision Points and Pathways
    a. “Getting to Zero” Carbon
        i. Motivations
            1. Regulations & Policy
                a. ETA (2019)
                    i. EPA - evolving
            2. Public Service in response to Mar 2023 IPCC report analysis - https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23
    b. Making “no regrets” decisions
        i. Minimizing investment risk
            1. Stranded assets
                a. Loss of public trust
        ii. Maximizing investment opportunity
            1. First to market w/ long term solutions
            2. Public trust and sentiment
        iii. Value of money vs future human life opportunities
    c. c. Regional Planning and Coordination
        i. Organized Market Opportunities
        ii. Future Regional Transmission Operator
5. Resources

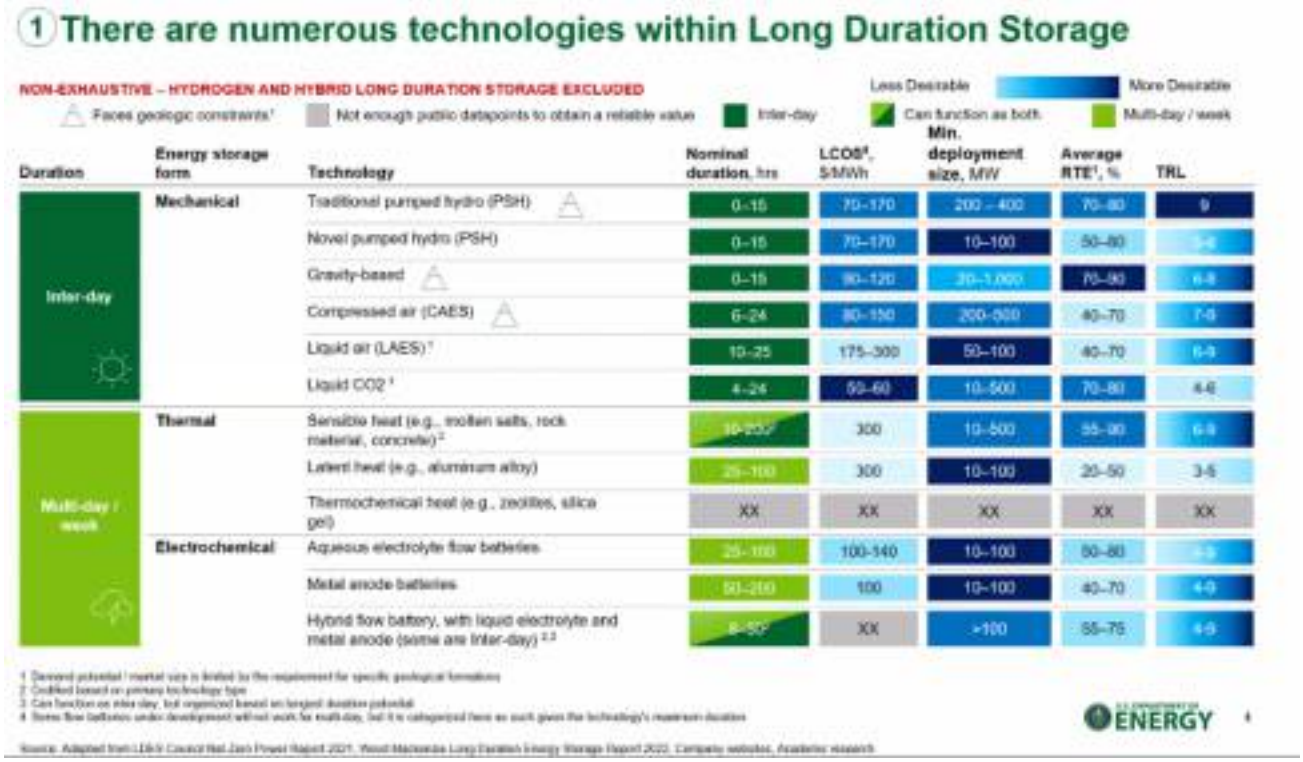
Resource Description:
A *brief* description of the resource; its technical characteristics.

Commercial Maturity:
The TRL level or similar metric to describe the commercial maturity of the resource. How long has it been

used in electric utility applications? This criteria needs to be done carefully. Some technologies have been the brunt of sabotage, business ineptness, and smear campaigns by the opponents.

Staged Cost:

This is a breakdown of cost by scale (if applicable). For example, solar may have a cost for 1 MW to 5 MW; and a different cost for 10 MW to 100 MW. And for storage it should also include RTE and similar variables as are in the below table.



1 There are numerous technologies within Long Duration Storage

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDED

Less Desirable — More Desirable

△ Faces geologic constraints[1] ▩ Not enough public datapoints to obtain a reliable value ■ Inter-day ◪ Can function as both ■ Multi-day / week

Duration	Energy storage form	Technology	Nominal duration, hrs	LCOS[2], $/MWh	Min. deployment size, MW	Average RTE[3], %	TRL
Inter-day	Mechanical	Traditional pumped hydro (PSH) △	6–15	70–170	200 – 400	70–80	9
		Novel pumped hydro (PSH)	6–15	70–170	10–100	50–80	5–8
		Gravity-based △	6–15	90–120	20–1,000	70–90	6–8
		Compressed air (CAES) △	6–24	80–150	200–500	40–70	7–8
		Liquid air (LAES)[4]	10–25	175–300	50–100	40–70	6–8
		Liquid CO2[4]	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	300	10–500	55–90	6–8
		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	7–8
		Metal anode batteries	50–200	100	10–100	40–70	4–6
		Hybrid flow battery, with liquid electrolyte and metal anode (some are inter-day)[2,3]	8–50	XX	>100	55–75	4–6

1 Demand potential / market size is limited by the requirement for specific geological formations
2 Credited based on primary technology type
3 Can function as inter-day, but organized based on longest duration potential
4 Some flow batteries under development will not work for multi-day, but it is categorized here as such given the technology's maximum duration

U.S. DEPARTMENT OF ENERGY

Source: Adapted from LDES Council Net Zero Power Report 2021, Wood Mackenzie Long Duration Energy Storage Report 2022, Company websites, Academic research

Grid Applications and Benefits:

Why is this resource important to the grid? What are its applications and benefits?

End of Life: From an Environmental engineering perspective, the proper heading should be "Life-Cycle Impacts"

And the Sub headings should be: 1) Greenhouse Gas emissions 2)Materials 3)Utility Disposal

- Candidate Resources
    - Renewable generation
        - Solar (including community solar)
        - Wind
        - Geothermal
- No new gas of any type
- Energy Storage
    - Short duration (up to 10 hr)
        - Lithium-ion battery etc. see below charts
    - Inter-day & Multi-day/week Long Duration Energy Storage (LDES) - see charts below ● Seasonal Shifting
        - Pumped-hydro storage, thermal energy storage, etc

    - Not for electric
- Potential New Resources
    - Adoption of new technologies
    - High Penetration of Distributed/Customer-owned Generation
    - Firming Plans
    - Energy efficiency and demand-response
    - Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
- [System Needs]
- Preferred Portfolio
    - [results of PNM modeling]
    - Potential pilot projects
    - [PNM conclusions]

DETERMINATION OF THE RESOURCE PORTFOLIO:

A. To identify the most cost-effective resource portfolio, utilities shall evaluate all supply- side resources, energy
storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.

B. The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.

C. The utility shall consider and describe ways to mitigate ratepayer risk.

D. Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:

(1) load management or modification and energy efficiency requirements;

(2) renewable energy portfolio requirements;

(3) existing and anticipated environmental laws and regulations, and, if determined by the commission, the
standardized cost of carbon emissions;

(4) fuel diversity;

(5) susceptibility to fuel interdependencies;

(6) transmission or distribution constraints; and

(7) system reliability and planning reserve margin requirements.

E. Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.

****

PARKING LOT

What describes end-of-life? For example, batteries may have an end-of-life when they can deliver only 70% of their nameplate capacity.

How is the resource disposed of at the end of its operational life?
Two resources that need to be included are Geothermal and Small Modular Reactors (SMR)>Small Modular Reactors go against the ETA requirement that 100% of IOU generation sources be renewable by…2045 or 2050. NM has been abused by the nuclear industry from cradle to grave. In addition, Germany has rightly retired its last 3 nuclear power plants this year recalling that 3 generations of use is now resulting in 30,000 generations of oversight of its waste. No thank you.

And again any new gas must be excluded. Methane is 85x more potent GHG than CO2 over 20 yrs, but because it exits the cycle within 12 yrs, it should be counted in the short term as 150-200x more potent.

Energy Efficiency

- PNM already offers a robust energy efficiency portfolio.
    - o The IRP should reflect that existing effort, likely as a load forecast modifier. However, there is incremental energy efficiency to gain in PNM's territory.
- PNM has developed bundles of energy efficiency measures which can be selected by the IRP models.
    - oThese bundles are quite comprehensive but additional details are needed around cost assumptions and omitted technologies.
    - oPNM should provide insight into the energy efficiency IRP selections by sector, technology, and cost.

Demand Response

- Another DSM area in which PNM has existing resources.
- This should be taken into account in the load forecast.
- PNM should identify new, incremental demand response that can be selected as a resource in the IRP model.

Load management

- Include time of use rates and other dynamic rate options.
- Should be modeled in any IRP efforts.
- A well-designed dynamic rate can change the load profile of customers and therefore the resources needed to meet demand in any given hour or day of the year.
- Different load shifting and adoption scenarios should be run

What are grid improvements needed for DSM to be quantifiably be included in the IRP? ● Assuming PNM receives approval in case 22-00058-UT, then the grid improvements needed to measure DSM impacts for accurate quantification will be coming online over the next few years. ● PNM does not have the visibility in the existing grid to effectively use DSM as a time and location based resource at this time.

How will PNM's programs such as Whole House Electric Vehicle (WHEV) rate impact DSM?

Will low-income customers get price incentives with smart meters?[1] And you should make the program voluntary, as there are real concerns for increased electromagnetic wave generation. Beyond the IRP discussion in my opinion. These issues are better for the energy efficiency filing.

PNM Integrated Resource Plan Facilitated Stakeholder Meeting #6
June 29, 2023 | 9:00am - 3:00pm MDT

LOCATION
CNM Workforce Training Center, Albuquerque

PURPOSE
Prepare stakeholders to provide input to the Action Plan in July and August.

KEY OUTCOMES
- Input to Statement of Need
- Review of modeling results to date
- Awareness of "APPENDIX A factors" in selection of most cost effective resource portfolio
- Candidate action plan ideas that are independent of modeling results

AGENDA

8:30 AM – Registration, coffee, and fruit

9:00 AM – Welcome, Purpose, and Outcomes for the Day, Gridworks

Schedule updates for July and August meetings

9:15 AM – Statement of Need Input Review and Discussion, Michael Barrio and Gridworks

10:15 AM – Modeling Insights and Observations, Form Energy

10:35 AM – Break

10:50 AM – Modeling Results to Date, PNM Team

11:50 AM – Factors for Selection of Most Cost Effective Portfolio, PNM Team and Gridworks

12:20 PM – Lunch, provided

12:35 PM – Modeling Deep Dive, Modeling Core Team and PNM Team

All stakeholders invited to attend

2:45 PM – Next steps, Meeting Survey

3:00 PM – Adjourn

Welcome!

Stakeholder Engagement Meeting
(Meeting #6)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, June 29
9:00 AM – 3 PM Mountain Daylight Time

Materials available at: [New Mexico Energy Planning – Gridworks](https://gridworks.org/initiatives/new-mexico-energy-planning/)

or

https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose and Outcomes of Today's Meeting

Prepare stakeholders to provide input to the Action Plan in July and August.

KEY OUTCOMES

- Input on Statement of Need
- Review of modeling results to date
- Awareness of "APPENDIX A factors" in selection of most cost effective resource portfolio
- Candidate action plan ideas that are independent of modeling results

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Agenda

9:00 AM – Welcome, Purpose, Outcomes for the Day, & Schedule Update, Gridworks

9:15 AM – Statement of Need Input Review and Discussion, Michael Barrio and Gridworks

10:15 AM – Modeling Insights and Observations, Form Energy

10:35 AM – Break

10:50 AM – Modeling Results to Date, PNM Team and Gridworks

11:50 AM – Factors for Selection of Most Cost-Effective Portfolio, PNM Team and Gridworks

12:20 PM – Pick up Lunch (provided) and return to session

12:35 PM – Modeling Deep Dive, Modeling Core Team and PNM Team. All stakeholders invited to attend.

2:45 PM – Next Steps, Meeting Survey

3:00 PM – Adjourn

Thank you for your Engagement as we Approach Action Plan Input

March – May	June – August	Sept – Nov

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

New stakeholders, if this is your first meeting with this group
Please type into the chat:

- Name
- Organization
- Your primary interest pertaining to the IRP

Meeting Schedule Changes

- **July 13, 2023, meeting has been moved to July 27**. This meeting will is scheduled for **9 AM – 12 NOON** to allow for more time to share additional modeling results.
- **August 17 meeting will be 9 AM – 12 NOON** to focus on input to the Action Plan

- OTHER ANNOUNCEMENTS?

Statement of Need Update

- Review of input to SoN
  - Team captain: Michael Barrio, Advanced Energy United
- Feedback process
  - Refer to written document
  - Prepare feedback (name and content on colored sticky notes)
  - Gridworks to summarize and document input in meeting summary
- Next steps
  - Editing, if warranted, by working group
  - Assess stakeholder consensus during July 27 meeting

Stakeholder Modeling Observations

Kailash Raman, Form Energy

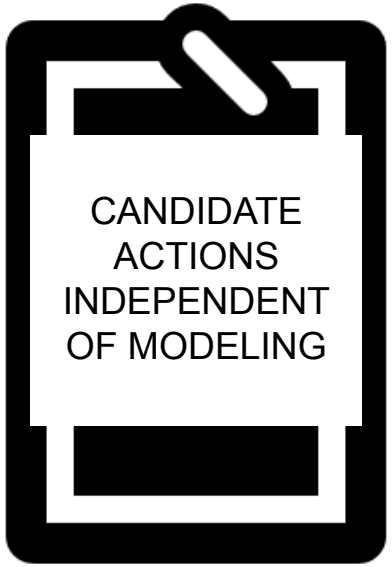
Questions? Contact Kailash

kraman@formenergy.com

Break

- Refresh
- Browse and contribute to the

"ACTION PLAN BRAINSTORM" flip chart, available all day



Modeling Result to Date Discussion

- PNM Team presentation, 45 minutes
- Facilitated Q&A, 15 minutes
  - What do you want to know more about?
  - Name and question or comment on 3x5 card
  - Questions of broad interest answered as time allows
  - Other questions provide topics for the deep dive session, starting at lunchtime

Modeling Results to Date

PNM TEAM

GRIDWORKS

Factors in Selecting Most Cost-Effective Portfolio

- Cost through projected life
- Mitigation of ratepayer risk
- Other factors
  1. load management or modification and energy efficiency requirements
  2. meeting renewable energy portfolio requirements
  3. existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions
  4. fuel diversity
  5. susceptibility to fuel interdependencies
  6. transmission or distribution constraints
  7. system reliability and planning reserve margin requirements

Reference:
IRP Rule, Appendix A, “Determination of the Resource Portfolio”

Summary
Next Steps
Meeting Survey

The Schedule Ahead Includes a Few Schedule Adjustments

March – May | June – August | Sept – Nov | IRP Filing Dec. 15

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

NEXT DEADLINE

July 13 - Requests by stakeholders who wish to share their own modeling results at upcoming meetings

SCHEDULED MEETINGS

- July 27, 9 AM – 12 NOON – SoN input consensus check; Results of prioritized stakeholder requested runs. Gather Action Plan suggestions that are unrelated to modeling results. Decide on additional SERVM runs, if necessary.
- Aug. 17, 9 AM – 12 NOON – Review results of additional modeling runs. Coordinate SoN and model results to draft input into Action Plan.
- Sept. 14, 9 AM – 10:30 AM – Finalize stakeholder input into Action Plan
- Oct. 19, 9 AM – 10:30 AM – Review IRP elements of greatest interest to stakeholders
- Dec. 19, 9 AM – 10:30 AM – Facilitated Stakeholder Process feedback collection

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

SUPPLEMENTAL SLIDES IF NEEDED

Modeling Core Team Update on Additional Stakeholder Requested Modeling Runs

Team captains:

- Aaron Gould, WRA
- Rachel Wilson, Form Energy
- Nick Phillips, PNM

Future CTP with high EV and high building electrification
Future CTP with increased DR
FCCP through Dec. 2027 + extension for Valencia through 2039
FCPP through Dec. 2027 + extension for Valencia & Reeves through 2039
No combustion scenario post 2039 – include solar, wind, Li-ion storage, long duration storage
No new combustion with thermal storage
Accelerated carbon free: two time frames, 2030 and 2035
Transmission expansion (from east) + many alternative resources
High and very high gas price
Extreme weather and other variable sensitivities
Western Regulatory Assistance Project modeling based scenario – regional market influences
Correlated gas outages

PNM 2023-2042 IRP: Modeling Results Update

FACILITATED STAKEHOLDER WORKSHOP

JUNE 29, 2023

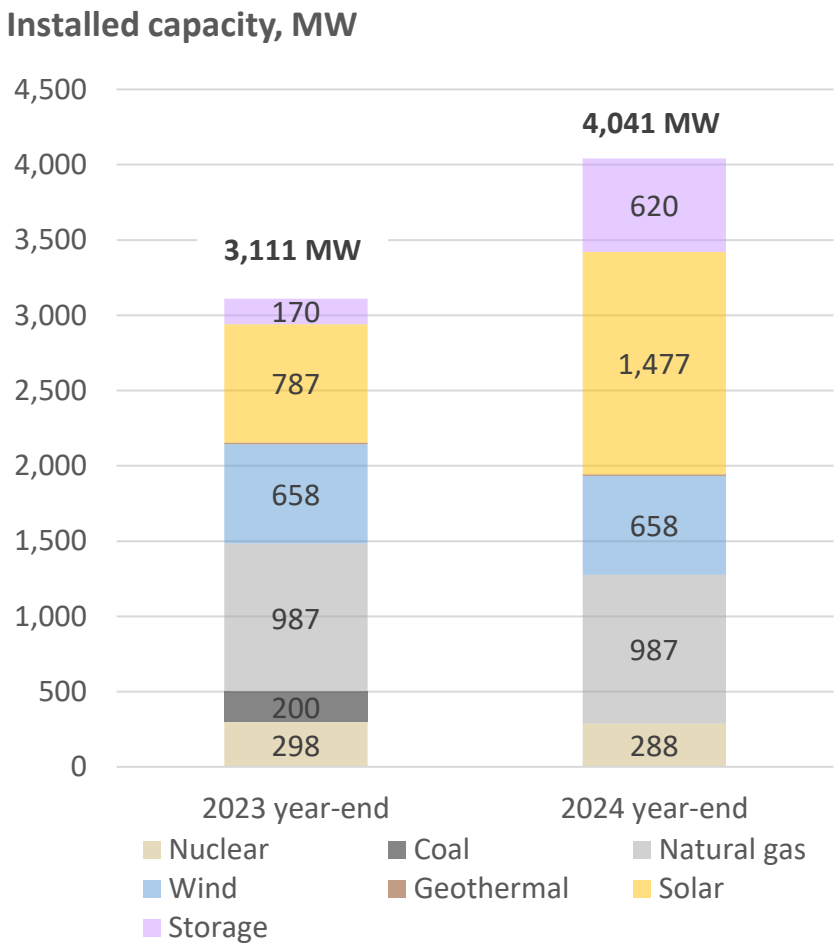


DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

PNM'S EXISTING RESOURCE PORTFOLIO AND NEAR-TERM RESOURCE ADEQUACY



2024 capacity

Storage: 620

Solar: 1,477

Wind: 658

Natural Gas: 987

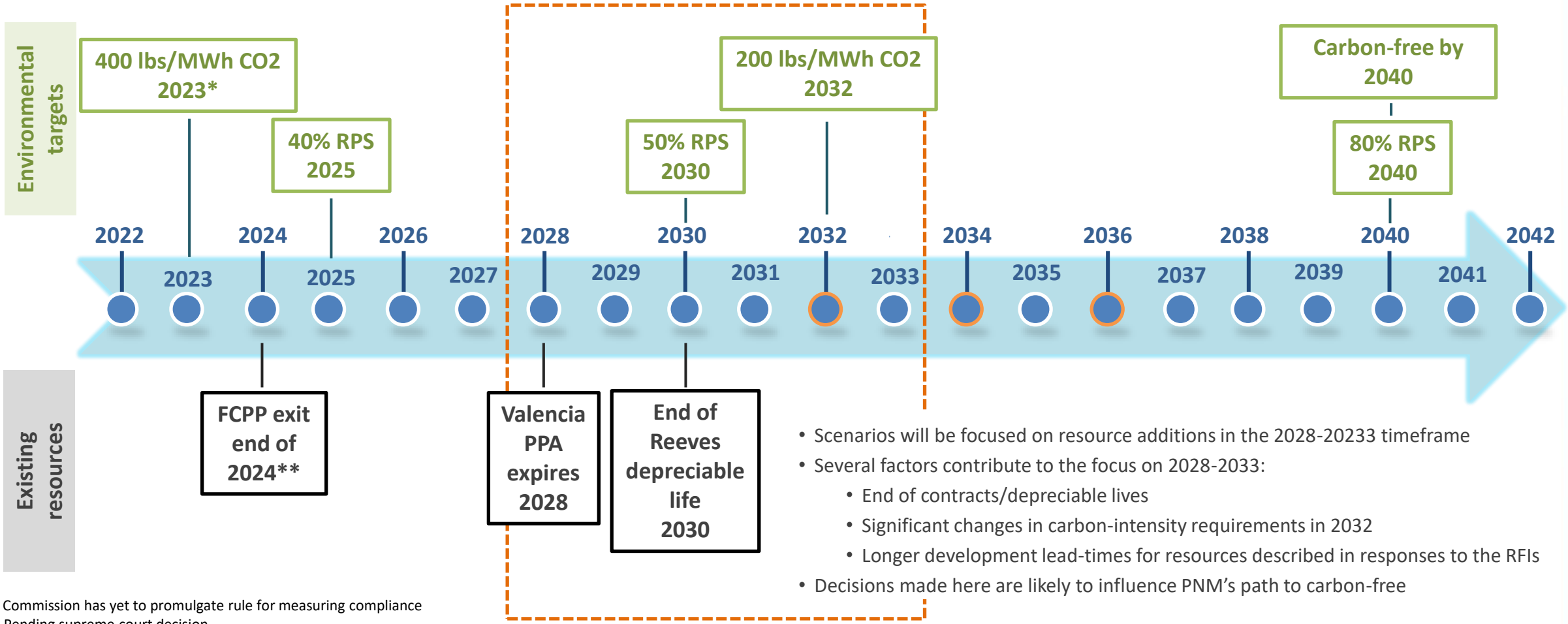
Coal: 0 MW (FCPP abandoned*)

Nuclear: 288 MW share of Palo Verde

*Pending appeal at NM Supreme Court

- Near term additions include 400 MW of solar and 170 MW of storage by the end of 2023
- By year-end 2024, PNM will have added an additional 690 MW of solar and 450 MW of storage
- RFPs for 2026-2028 are currently ongoing

KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS POINT TO 2028-2033 AS A CRITICAL PERIOD



- Scenarios will be focused on resource additions in the 2028-20233 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs
- Decisions made here are likely to influence PNM's path to carbon-free

* Commission has yet to promulgate rule for measuring compliance
** Pending supreme court decision

TECHNOLOGIES AVAILABLE IN PHASES 1-2

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



Energy efficiency and demand response included in all scenarios

DISCLAIMER - RESULTS ARE PRELIMINARY DRAFT

- PNM has incorporated numerous updates to its modeling in this IRP cycle
- While we have taken every effort to ensure the validity of these techniques, please understand that the results we will discuss are considered preliminary draft results and will likely change as we continue to refine the analysis
- In previous IRP cycles we would not present results before a full draft of the IRP was ready; we have made efforts to get stakeholders involved earlier in this IRP cycle, starting the public advisory process earlier than ever
- In order to maximize stakeholder involvement, presenting preliminary results and inviting feedback earlier is equally important
- At this stage, we will highlight some of the key trends we see so far, and some of the areas that require further study and refinement

PHASE 1 SCENARIOS EXPLORE ATTRIBUTES OF A VARIETY OF TECHNOLOGIES

Scenario Name	Scenario-Specific Assumptions
Base technologies	Only solar, storage, and EE, DR allowed through 2032
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 energy 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 hydrogen-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
H2 - 250 MW	~250 MW hydrogen-fueled CT & ~750 MW electrolyzer added in 2031

- In Phase 1, technology-specific scenarios are screened under the following conditions:
  1. **CT&P future (capacity expansion run)**
     a) P50 load 8760 production cost run
     b) Extreme weather load 8760 production cost run
  2. **CT&P + Stable ED Growth (capacity expansion run)**
     a) P50 load 8760 production cost run

- **This approach gives PNM the ability to evaluate scenarios based on:**
  - Overall cost
  - Cost difference to incorporate strong ED growth
  - Ability to accommodate extreme weather load
- All portfolios include option to add base technologies (including DR and EE) at any time
- ***All portfolios required to meet reliability, RPS, and carbon-intensity targets***

Preliminary

PNM Talk to us. PNM.com

PHASE 2 SCENARIOS EXPLORE SYNERGIES BETWEEN TECHNOLOGIES

Scenario Name	Scenario-Specific Assumptions
70-hr PHS + CTs	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready CTs allowed
70-hr PHS + linear generators	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready linear generators allowed
70-hr PHS, CTs, wind expansion	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
70-hr PHS + carbon capture	300 MW of pumped storage (70-hr) by 2032; Afton CC (235 MW) retrofitted with CCS capability
8-hr PHS + CTs	300 MW of pumped storage (8-hr) by 2032; new hydrogen-ready CTs allowed
8-hr PHS + linear generators	300 MW of pumped storage (8-hr) by 2032; new hydrogen-ready linear generators allowed
8-hr PHS + CTs + wind expansion	300 MW of pumped storage (8-hr) by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
8-hr PHS + carbon capture	300 MW of pumped storage (8-hr) by 2032; Afton CC (235 MW) retrofitted with CCS capability
IAS + CTs	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready CTs allowed
IAS + CTs + wind expansion	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
IAS + linear generators	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready linear generators allowed
IAS + carbon capture	At least 100 MW of iron air energy storage by 2032; Afton CC (235 MW) retrofitted with CCS capability
IAS + LAES	At least 100 MW of iron air energy storage and at least 100 MW liquid air energy storage by 2032
CAES + wind expansion	At least 100 MW of compressed air energy storage by 2032; new wind beginning in 2028
Wind expansion with co-located battery storage	New wind & associated transmission allowed beginning in 2028
H2 (250 MW) + wind expansion	New wind & associated transmission allowed beginning in 2028

- In Phase 2, PNM designed more complex portfolios consisting of two or more RFI technologies – the intent is to explore synergistic effects of combining operating characteristics
- All portfolios include option to add base technologies (including DR and EE) at any time
- Scenarios are screened under the same conditions as in Phase 1
- ***All portfolios required to meet reliability, RPS, and carbon-intensity targets***

Preliminary

PNM Talk to us. PNM.com

PNM MODELING RESULTS UPDATE – PRELIMINARY

PROPOSED PORTFOLIO EVALUATION CRITERIA: PHASES 1-2

RELIABILITY

- Measured by unserved energy under extreme weather conditions (deterministic)
- Comparison of portfolio ability to accommodate incremental load

COST

- Measured as present Value of Revenue Requirement, which reflects total cost of portfolio across study period
- Comparison of overall costs

TECHNOLOGY RISK

- Measured as a weighted average Technology Readiness Level
- Each portfolio assigned a weighted average TRL based on the 2042 firm capacity breakdown
- Comparison of dependence on less proven technologies on a capacity basis

CARBON EMISSIONS

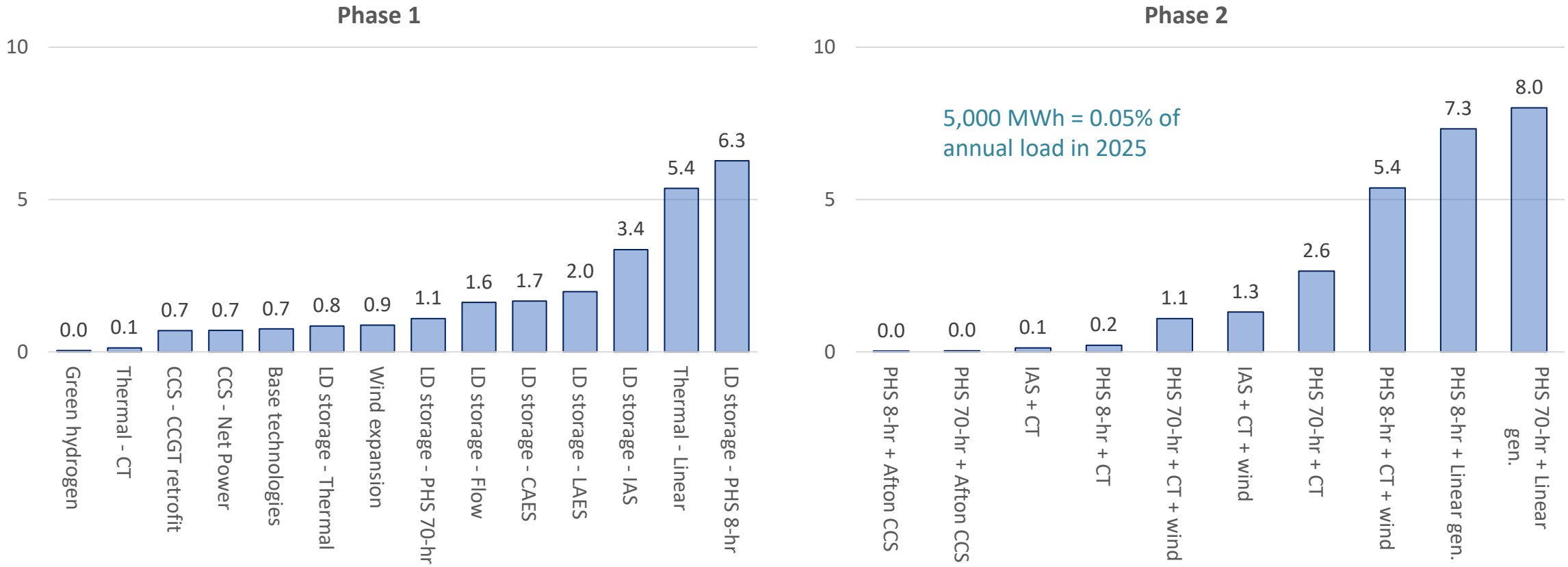
- Measured as total carbon emissions across study period
- Comparison of carbon emissions associated with scenario-specific combination of technologies

SCALABILITY

- Measured as incremental PVRR under Economic Development scenario
- Comparison of costs to scale scenario-specific combination of technologies

PORTFOLIOS RANKED BY UNSERVED ENERGY UNDER EXTREME WEATHER LOAD CASE

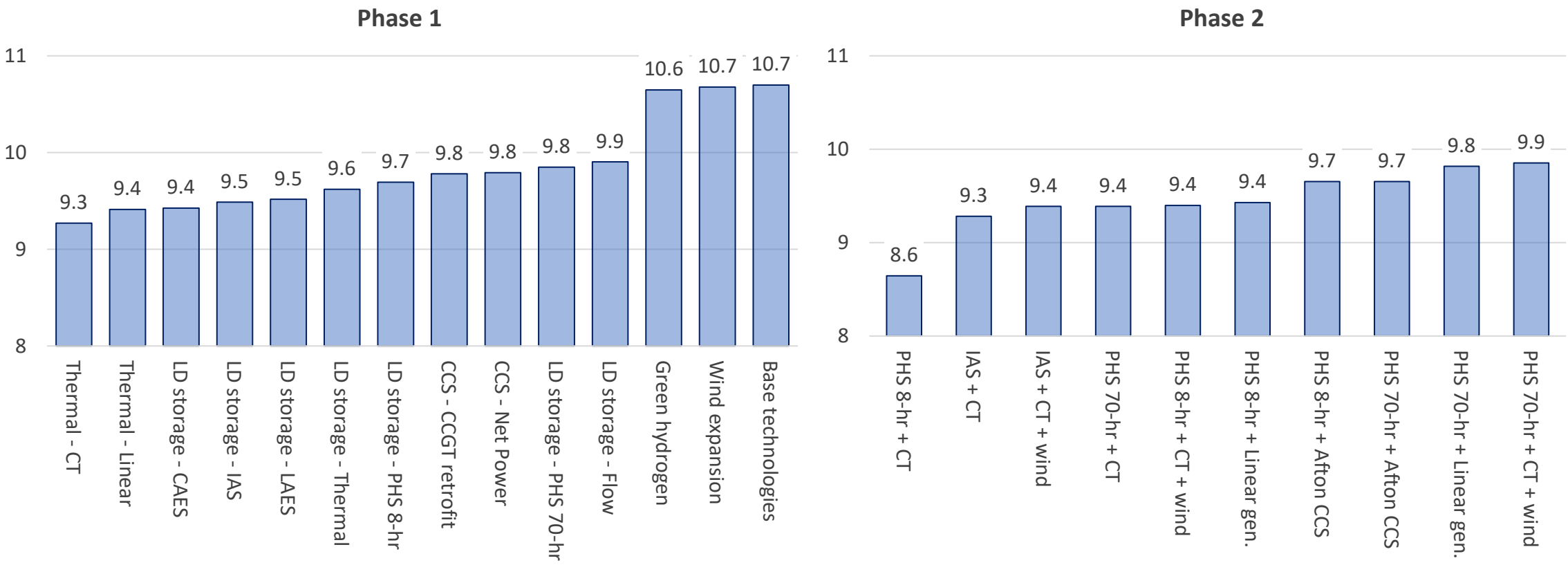
Unserved energy under extreme weather load case, 2026-2042 GWh



Preliminary results

PORTFOLIOS RANKED BY PRESENT VALUE OF REVENUE REQUIREMENT

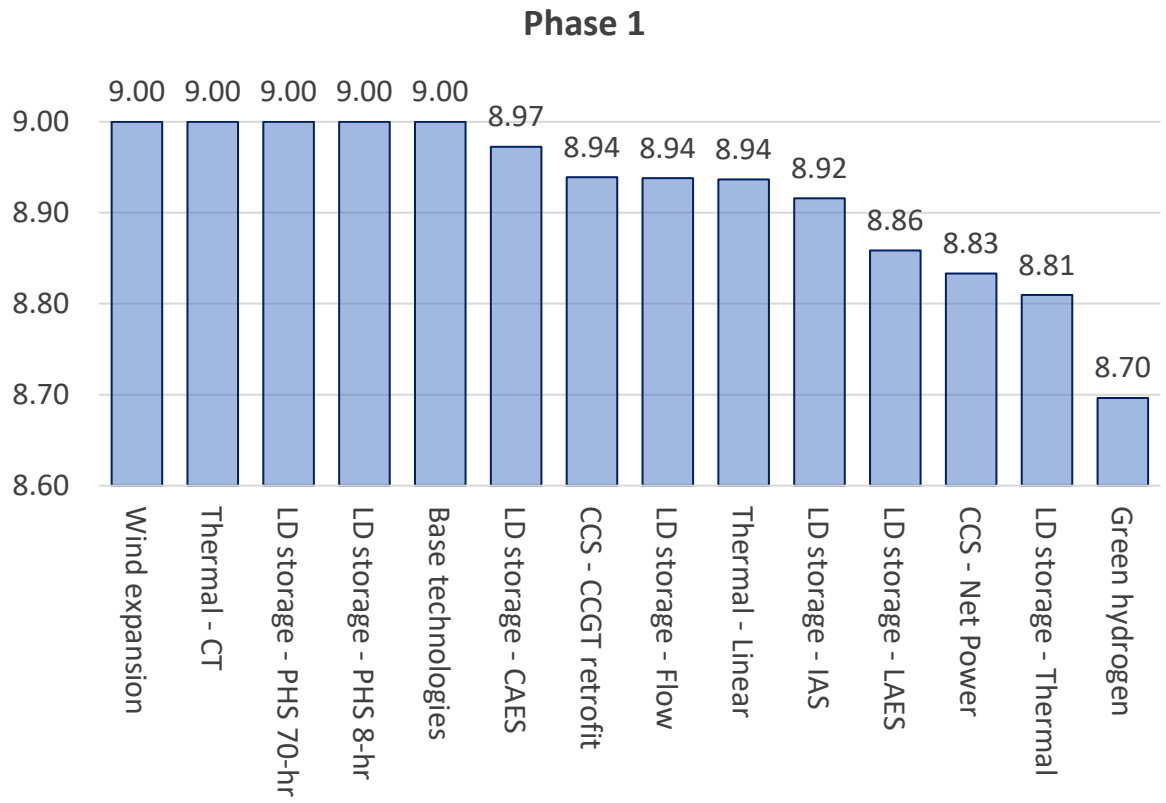
Present value of Revenue Requirement, $B

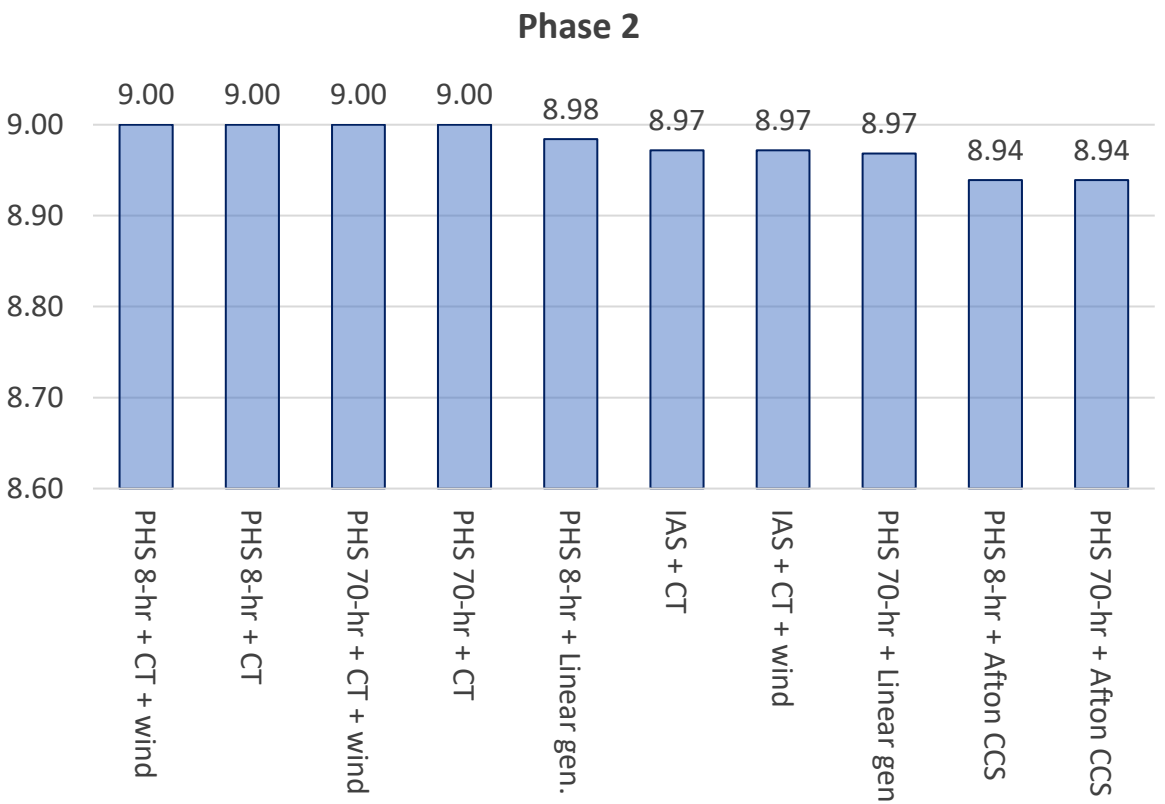


Preliminary results

PORTFOLIOS RANKED BY WEIGHTED AVERAGE TECHNOLOGY READINESS LEVEL

Weighted average TRL

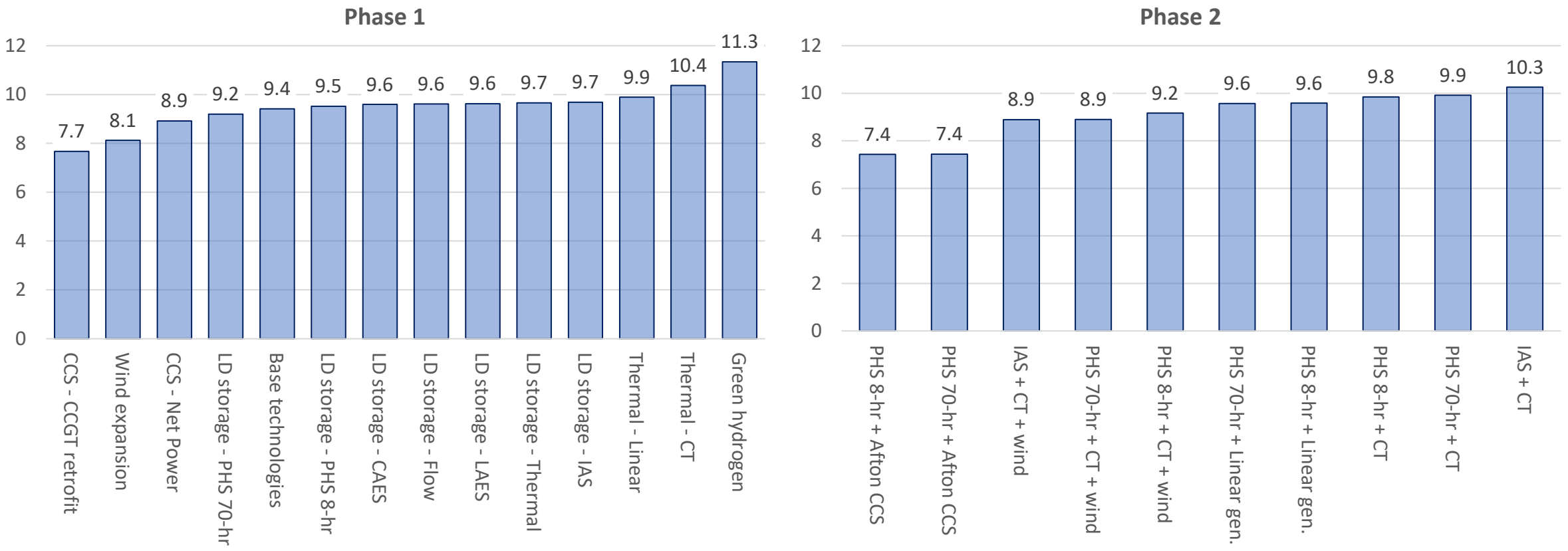




Preliminary results

PORTFOLIOS RANKED BY TOTAL CARBON EMISSIONS 2023-2042

Carbon emissions 2026-2042, MM tons



Preliminary results

EVALUATION CRITERIA IN IRP RULE (APPENDIX A)

DETERMINATION OF THE RESOURCE PORTFOLIO:

A. To identify the most cost-effective resource portfolio, utilities shall evaluate all supply- side resources, energy storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.

B. The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.

C. The utility shall consider and describe ways to mitigate ratepayer risk.

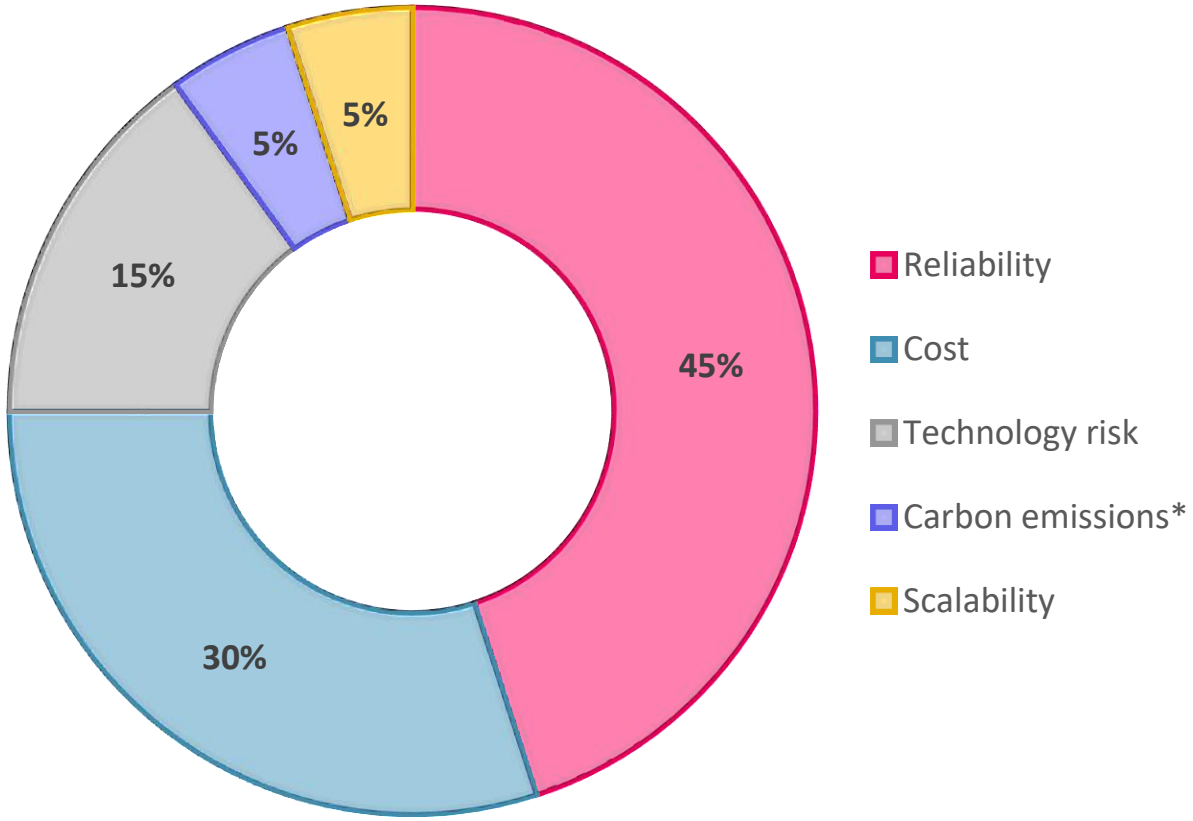
D. Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:

- **(1)** load management or modification and energy efficiency requirements;
- **(2)** renewable energy portfolio requirements;
- **(3)** existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions;
- **(4)** fuel diversity;
- **(5)** susceptibility to fuel interdependencies;
- **(6)** transmission or distribution constraints; and
- **(7)** system reliability and planning reserve margin requirements.

E. Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.

SCORING MATRIX APPROACH AND POTENTIAL CRITERIA WEIGHTING (PHASE 1 & 2)

Preliminary PNM evaluation criteria weighting for overall portfolio score



***All portfolios meet carbon intensity and RPS requirements**

- Each portfolio is given a score for each metric
- Scores range from 1 to 10, with 1 being the highest possible score
- For example, the portfolio with the lowest PVRR across all portfolios receives a score of 1 for the PVRR metric, the portfolio with the highest PVRR receives a score of 10
- The scores are then weighted and summed for a final portfolio score; portfolios with lower scores are preferred

Preliminary

SAMPLE PORTFOLIOS SCORED USING PRELIMINARY PNM CRITERIA AND WEIGHTING SCHEME (PHASES 1-2)

	Technologies	Base technologies	LD storage - CAES	LD storage - Flow	LD storage - IAS	LD storage - LAES	LD storage - PHS 8-hr	LD storage - PHS 70-hr	LD storage - Thermal	Thermal - CT	Thermal - Linear	Wind expansion	CCS - CCGT retrofit	CCS - Net Power	Green hydrogen
	Future	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P	CT&P
UE	Extreme load unserved energy	749	1,666	1,625	3,355	1,977	6,266	1,091	847	129	5,362	873	698	703	40
	Score	2.03	3.35	3.29	5.79	3.80	10.00	2.52	2.17	1.13	8.69	2.21	1.95	1.96	1.00
	Weight	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
	Weighted score	**0.91**	**1.51**	**1.48**	**2.61**	**1.71**	**4.50**	**1.13**	**0.98**	**0.51**	**3.91**	**0.99**	**0.88**	**0.88**	**0.45**
PVRR	Base PVRR	10.70	9.43	9.90	9.49	9.52	9.45	9.85	9.62	9.27	9.41	10.68	9.78	9.79	10.65
	Score	10.00	1.99	4.99	2.37	2.57	2.12	4.65	3.21	1.00	1.90	9.86	4.21	4.30	9.68
	Weight	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
	PVRR weighted score	**3.50**	**0.70**	**1.75**	**0.83**	**0.90**	**0.74**	**1.63**	**1.12**	**0.35**	**0.67**	**3.45**	**1.47**	**1.50**	**3.39**
Weighted average TRL	TRL	9.00	8.97	8.94	8.92	8.86	9.00	9.00	8.81	9.00	8.94	9.00	8.94	8.83	8.70
	Score	1.00	1.82	2.84	3.50	5.19	1.00	1.00	6.65	1.00	2.88	1.00	2.81	5.95	10.00
	Weight	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
	Weighted score	**0.15**	**0.27**	**0.43**	**0.52**	**0.78**	**0.15**	**0.15**	**1.00**	**0.15**	**0.43**	**0.15**	**0.42**	**0.89**	**1.50**
CO2 emissions	CO2, MM tons	9.4	9.6	9.6	9.7	9.6	9.5	9.2	9.7	10.4	9.9	8.1	7.7	8.9	11.3
	Score	5.26	5.71	5.77	5.94	5.79	5.55	4.74	5.86	7.60	6.45	2.10	1.00	4.06	10.00
	Weight	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	Weighted score	**0.26**	**0.29**	**0.29**	**0.30**	**0.29**	**0.28**	**0.24**	**0.29**	**0.38**	**0.32**	**0.11**	**0.05**	**0.20**	**0.50**
	Total score	**4.82**	**2.76**	**3.94**	**4.26**	**3.68**	**5.67**	**3.15**	**3.39**	**1.39**	**5.33**	**4.70**	**2.82**	**3.48**	**5.84**
	Rank	**11**	**2**	**8**	**9**	**7**	**13**	**4**	**5**	**1**	**12**	**10**	**3**	**6**	**14**

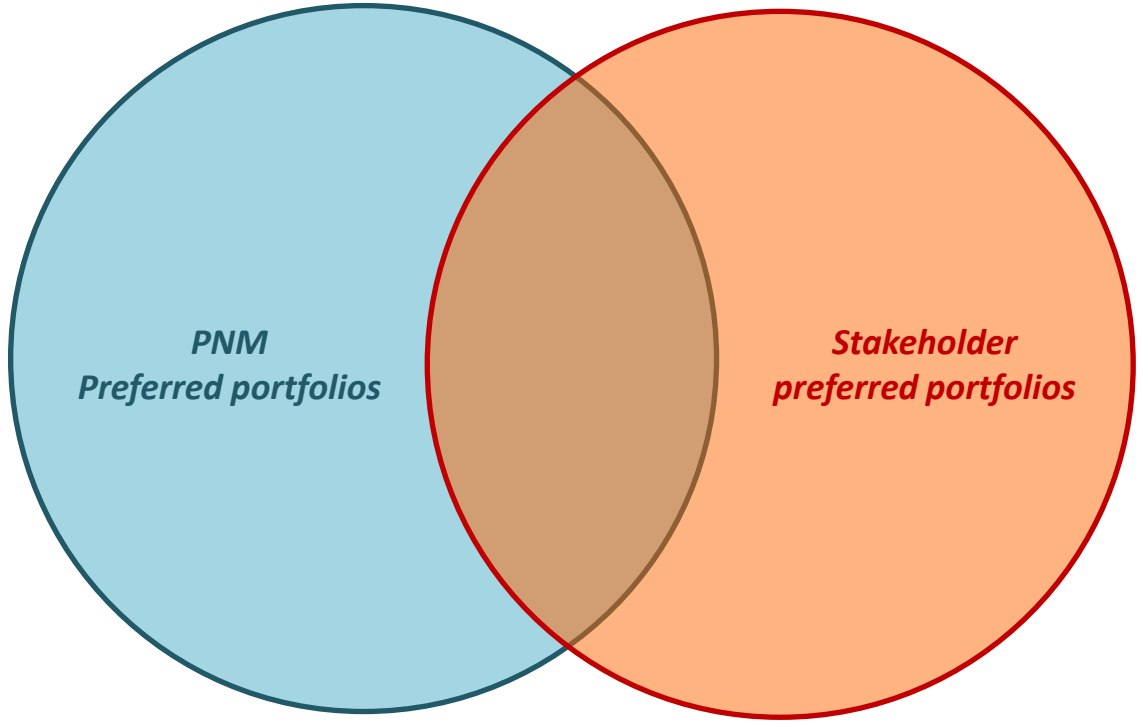
All portfolios required to meet reliability, RPS, and carbon-intensity targets

Preliminary

PNM Talk to us. PNM.com

PORTFOLIO SCORING SYSTEM

- PNM proposes that stakeholders evaluate modeled portfolios using the same methodology as PNM, but with their own criteria and weighting scheme for portfolio scoring
- PNM suggests that stakeholders determine their evaluation criteria, and for each criterion, a metric for measurement and an associated weight
- These can then be to determine an overall portfolio score for each portfolio modeled
- Once stakeholders have a list of preferred portfolios based on their criteria and weighting scheme, preferred portfolios can be compared



PNM'S INITIAL OBSERVATIONS & NEXT STEPS

Observations

- Lowest-cost portfolios include dispatchable technologies or long-duration storage
- Technology combinations provide lower-cost alternatives to single-technology scenarios
- Base technologies results in a very high level of builds – which translates to high cost
- Portfolios with wind and/or carbon capture technologies have the lowest carbon emissions
- Wind helps to decarbonize the system and is included in all portfolios; however, earlier transmission expansion doesn't drive significant cost savings
- Portfolios with TRLs below 9 represent some technology risk; we recognize the importance of due diligence around technology risks given our carbon-free target
- Unserved energy under extreme weather cases is lowest for portfolios with CTs and/or CCS

Next Steps

- Continue to refine modeling approaches
- Continue to evaluate hybrid scenarios that combine most attractive options identified so far (complete Phase 2)
- Examine robustness of initial observations against key uncertainties (Phase 3)
- Explore implications of technology cost uncertainty upon results that rely heavily on emerging technologies (Phase 3)
- Evaluate the cost to add additional wind/solar/battery storage capacity by 2040 should the opportunity to use an alternative cost-effective fuel fail to materialize
- Conduct reliability modeling of most promising portfolio options (SERVM)

Preliminary results

STAKEHOLDER MODELING RUN REQUESTS

UPDATE ON STAKEHOLDER MODELING RUN REQUESTS

Modeling run requests – EnCompass

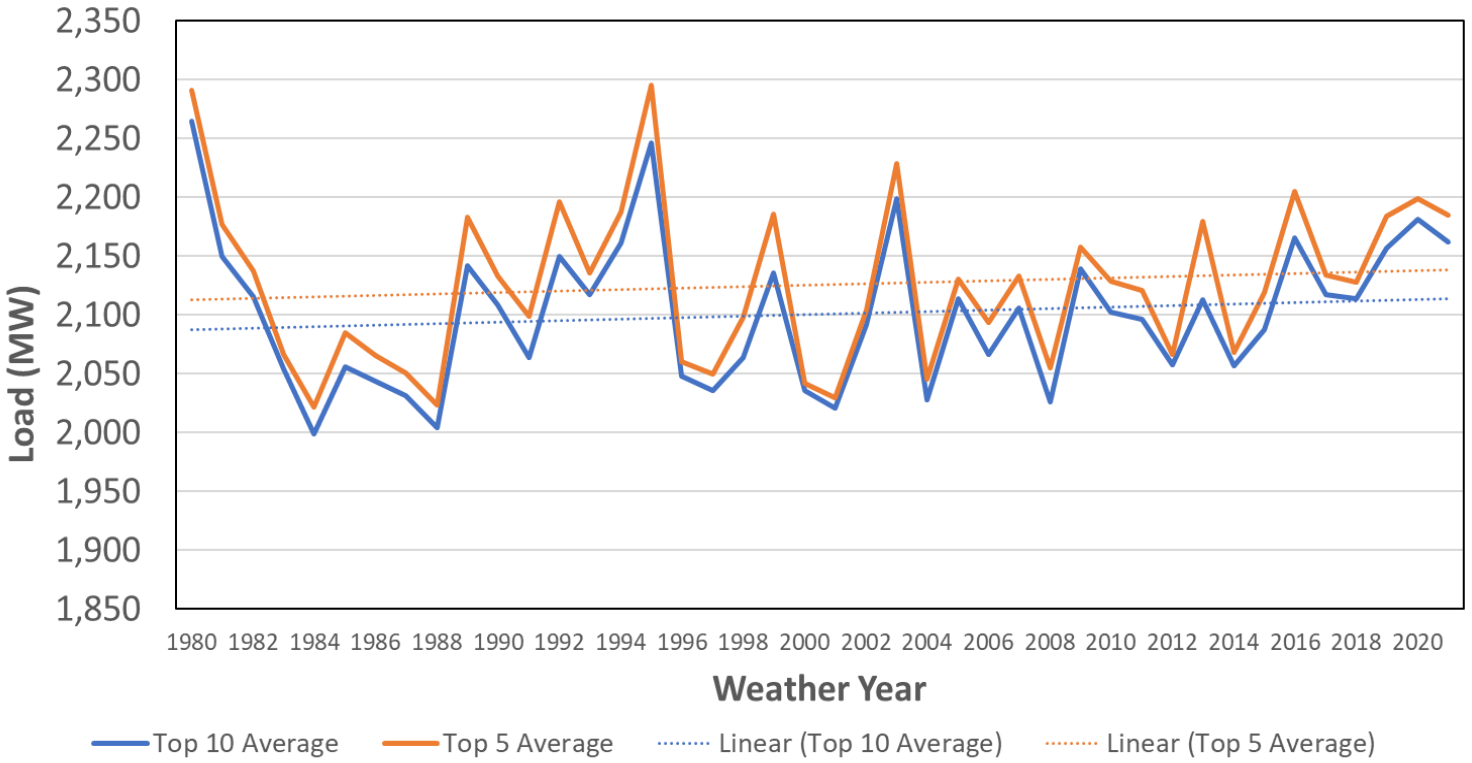
- Future CTP with high EV and high building electrification – CT&P future; base technologies and long duration storage available
- Increased DR – CT&P future; base technologies and generic combustion turbines available
- Four Corners available through December 2027 with Valencia extension to 2041 – CT&P future; base technologies available, no combustion post 2039
- Four Corners available through December 2027 with Valencia and Reeves extension to 2041 – CT&P future; base technologies available, no combustion post 2039
- No combustion post 2039 – CT&P future; base technologies, long duration storage available
- Accelerated carbon-free 2035 – National Carbon Policy future; base technologies, wind expansion, and long duration storage available; CO2-free by 2035
- Accelerated carbon-free 2030 – National Carbon Policy future with adjustment to load for increased EV adoption; base technologies, wind expansion, and long duration storage available; CO2-free by 2030
- Transmission expansion plus – CT&P future; base technologies, wind expansion, long-duration storage, generic CTs, and linear generators available
- Gas price breakeven study – CT&P future; capacity expansions in which base technologies and generic CTs available under increasingly high gas price sensitivities

Modeling run requests / questions– SERVM

- LOLE impact analysis – explore factors that have greatest impact on LOLE by analyzing a case with a) poor battery performance, **b) heavier weighting on extreme weather years and/or years with relatively low renewable production**
- **WRAP modeling – explore changes in internal reserve requirements that might result from an organized market**
- **Correlated Gas Outages**

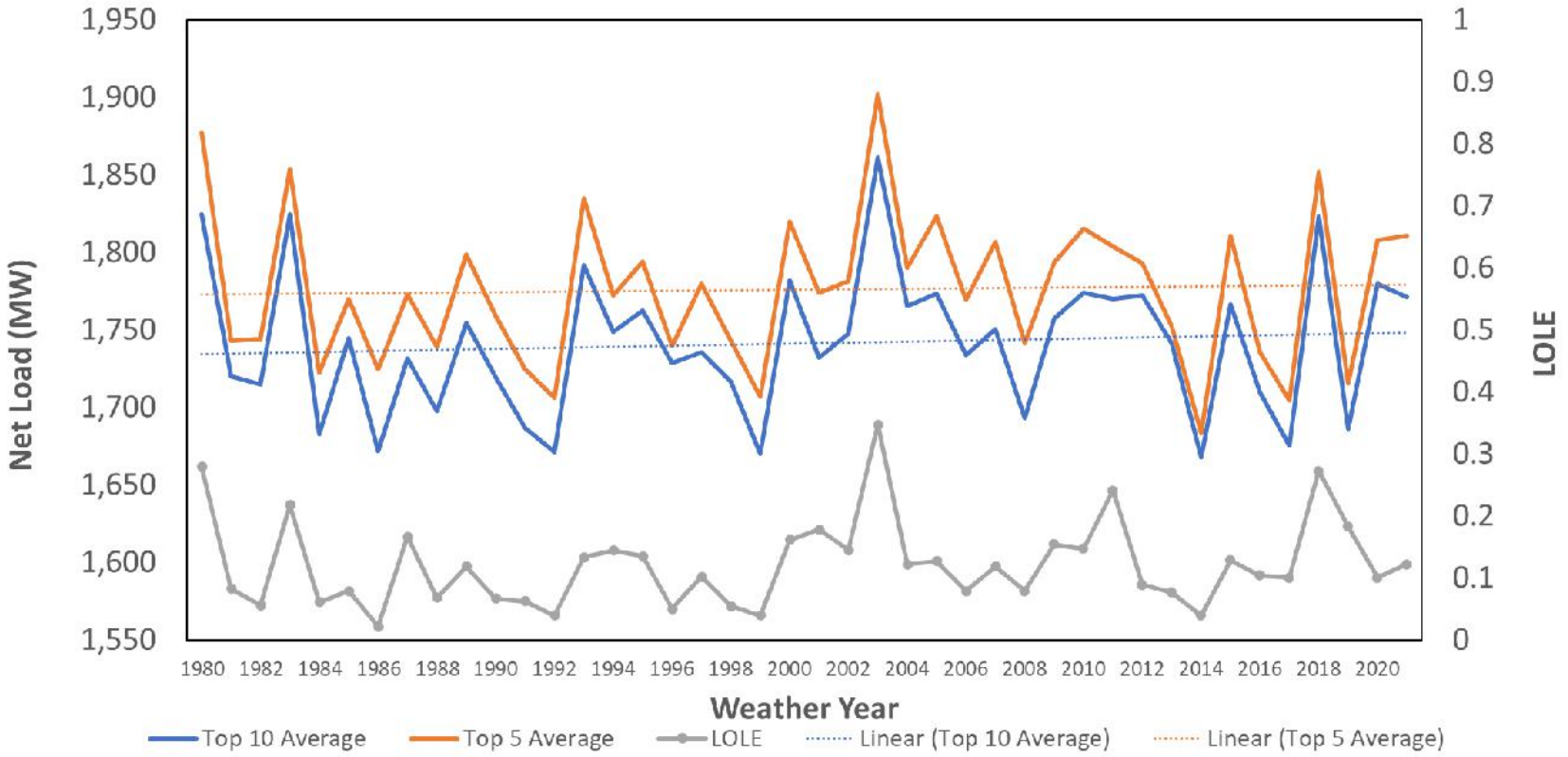
LOAD IN HIGHEST HOURS INCREASES OVER TIME

PNM average peak load in top hours by weather year, MW



- Top 5 Hour Slope: 0.61
- Top 10 Hour Slope: 0.65

LOLE IS HIGHER WHEN MORE WEIGHT IS PLACED ON RECENT WEATHER YEARS



Weighting	LOLE
Most recent 5 Years	0.155
Most recent 10 Years	0.121
Most recent 20 Years	0.139
Most recent 30 Years	0.127
Most recent 42 Years	0.121
Worst 5 Years 3x Probability	0.162

LOAD DIVERSITY

Average Peak Load (MW)		
Total System	PNM	PNM When System at Peak
38,400	2,151	2,054

PNM averages 95% of peak load when the total system is peaking

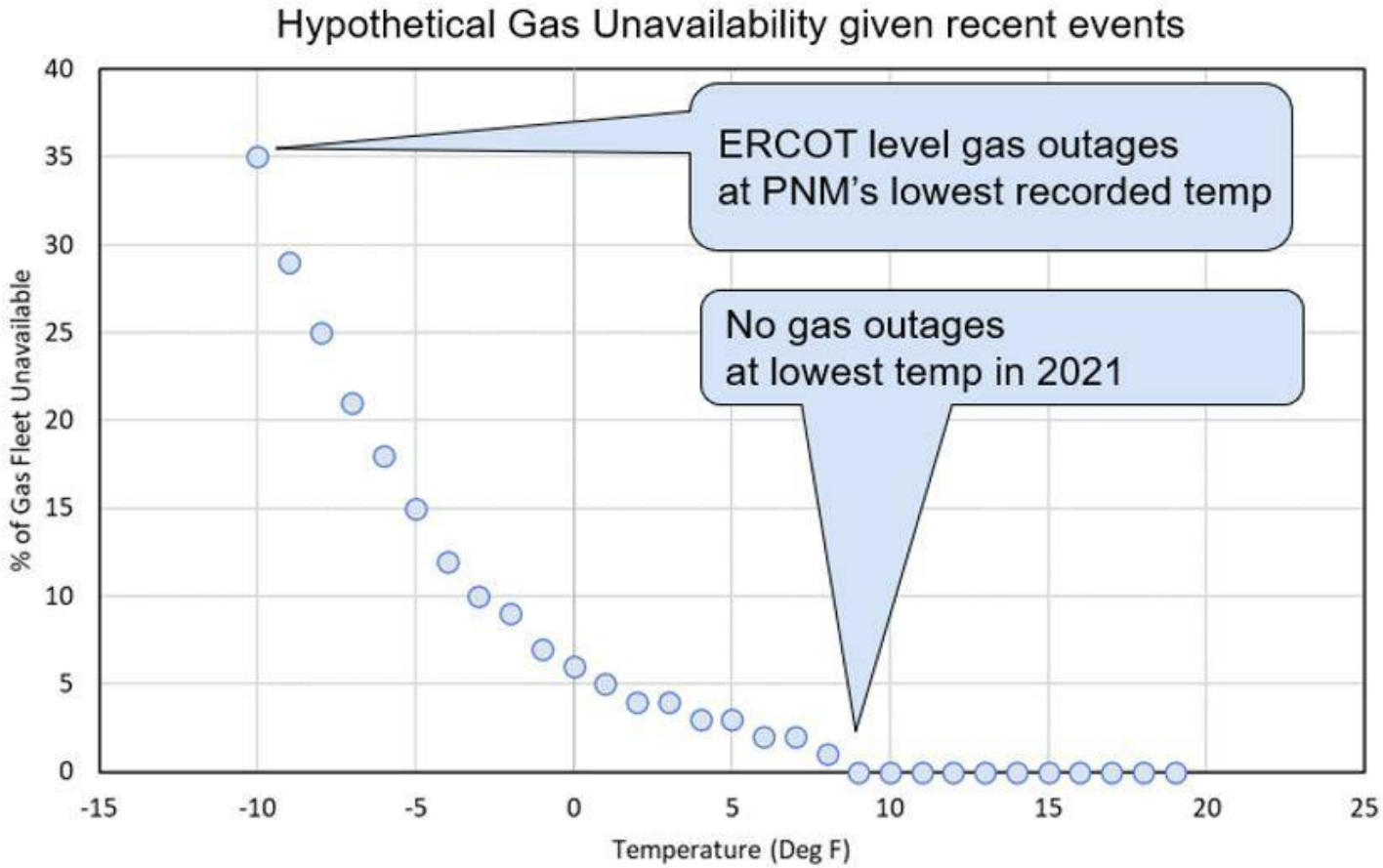
- Averages over 43 weather years
- System includes PNM, Tri-State, EPE, Arizona, SPS, PSCO

MARKET SENSITIVITY

Market Parameters	2025 Need (MW)
Island	410
Current Model	295
No Peak Load Constraints	30

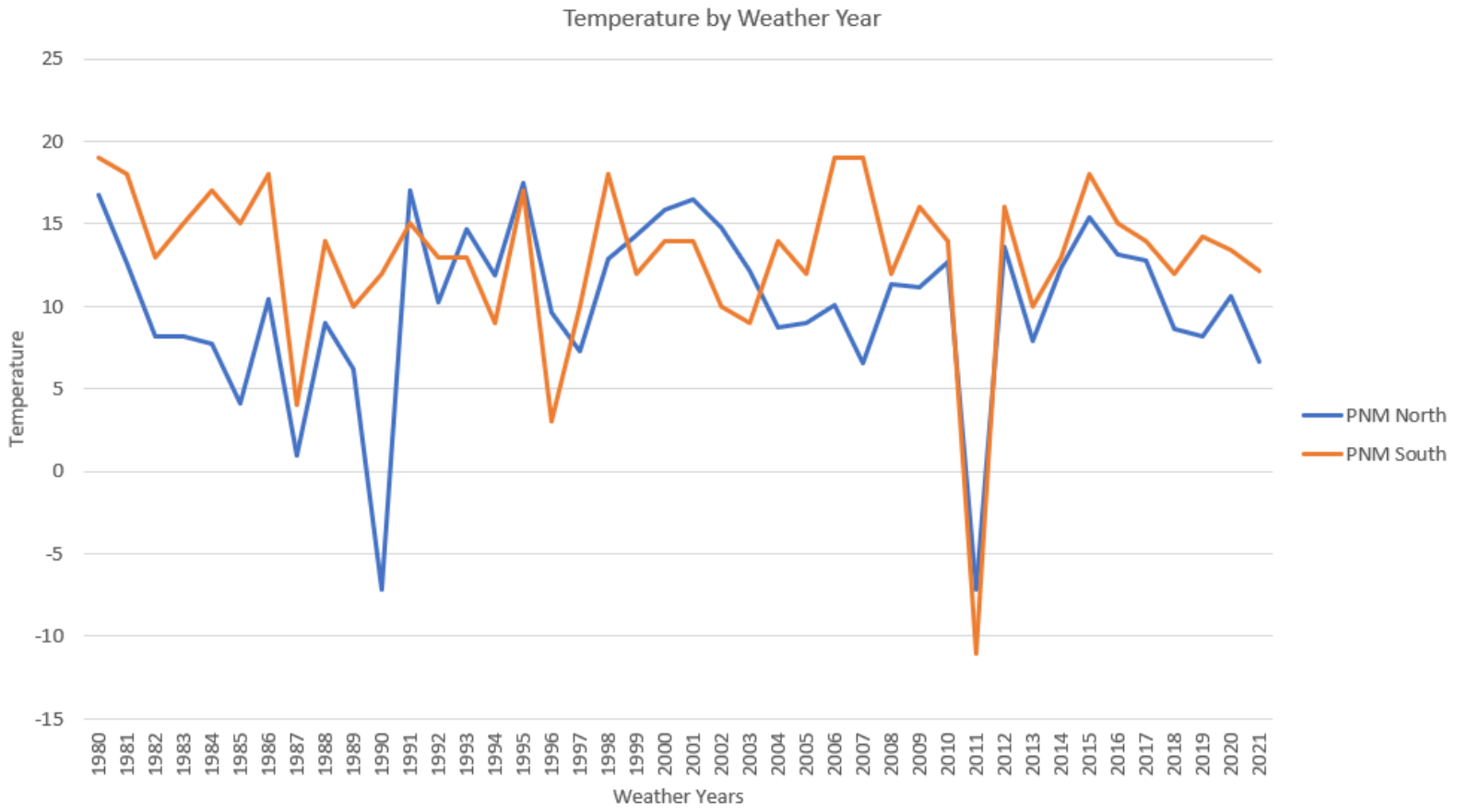
*0.1 LOLE Target

COLD WEATHER OUTAGES

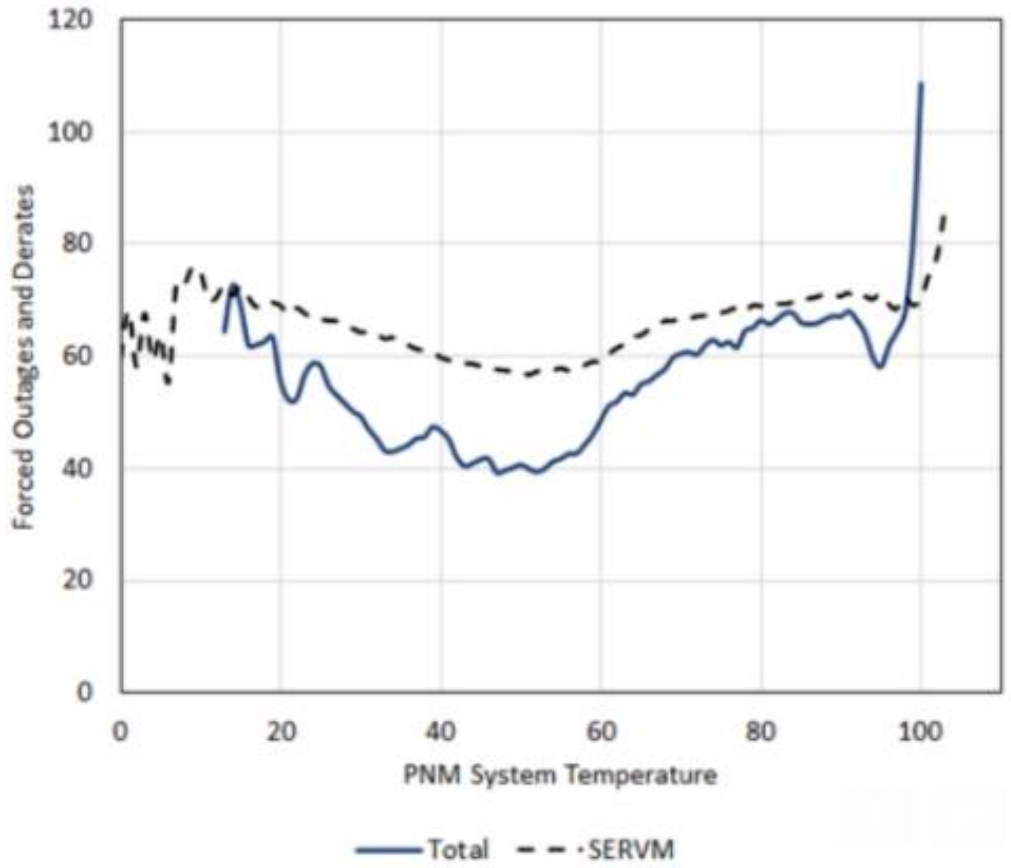


Talk to us.

TEMPERATURE HISTORY



PNM HISTORICAL OUTAGES BY TEMPERATURE



Talk to us.

MARGINAL GAS ELCC – CORRELATED OUTAGES

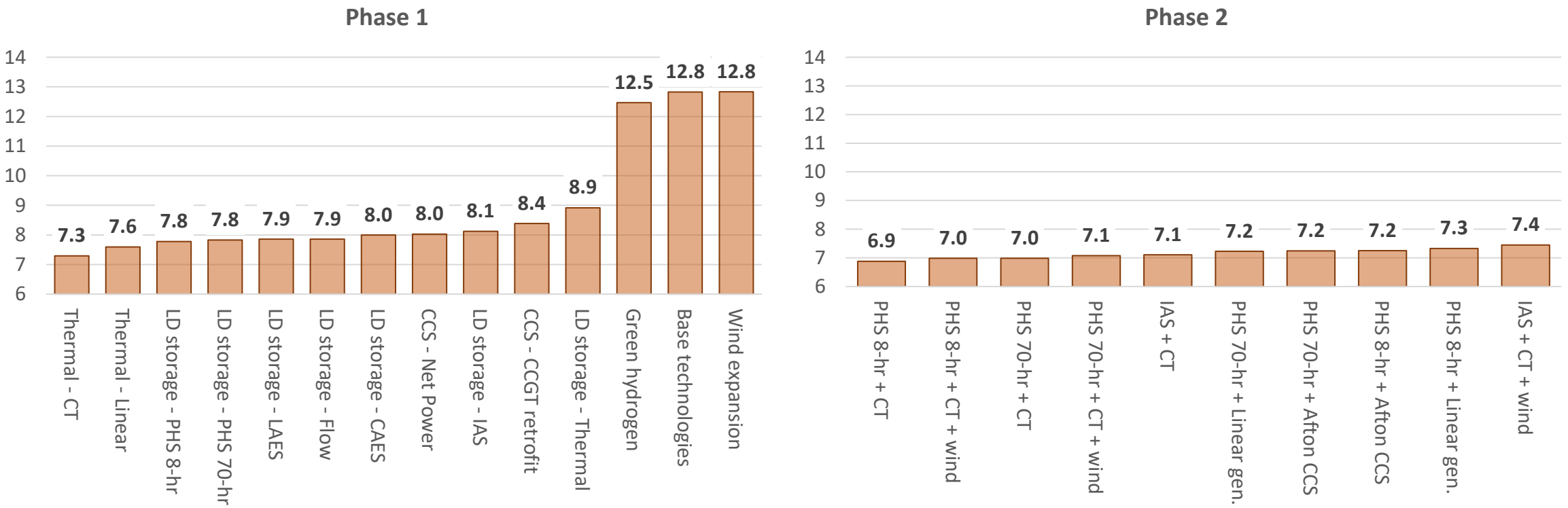
Incremental Capacity (MW)	ELCC (MW)	ELCC (%)
427	425	>95%

*Marginal ELCC value is slightly larger than 1-EFOR. This is due to 10 small units being added to a large system. There could also be some slight convergence noise but in general these incremental gas resources are greater than 95% ELCC.

DETAILED MODELING RESULTS - PRELIMINARY

2042 CAPACITY BY SCENARIO

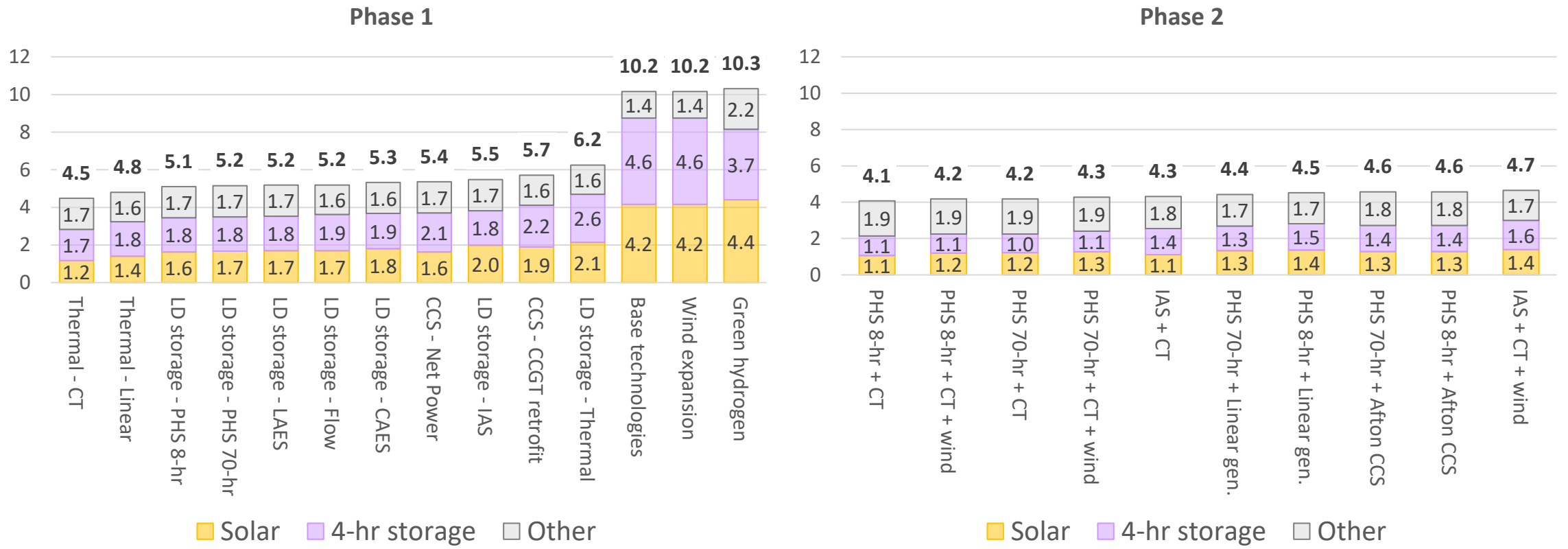
2042 nameplate capacity, GW



Preliminary results

NEW RESOURCE ADDITIONS BY 2042 (GENERIC/RFI ADDITIONS 2025-2042, DOES NOT REFLECT RETIREMENTS)

Cumulative additions of generic and RFI resources by 2042, GW

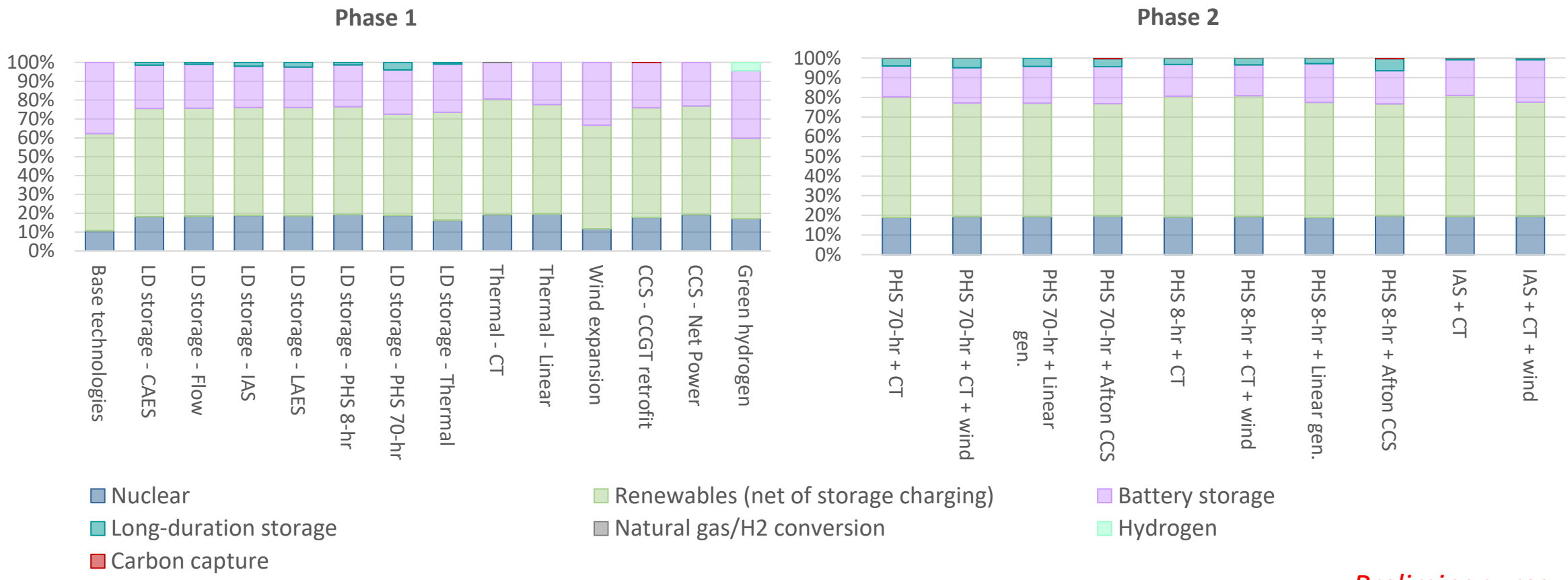


Preliminary results

PNM Talk to us. PNM.com

2040 GENERATION BY FUEL TYPE BY SCENARIO

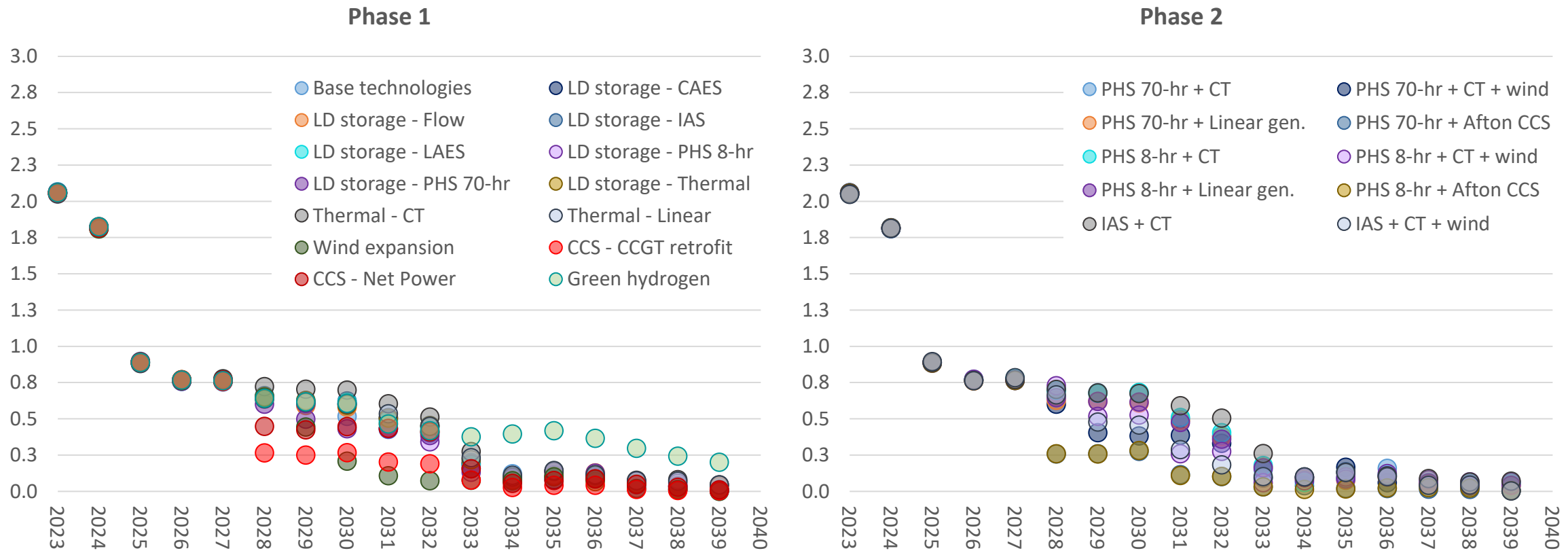
2040 generation, % of total



Preliminary results

CO2 EMISSIONS BY YEAR AND SCENARIO

CO2 emissions, MM tons



Preliminary results

WIND DROUGHTS

Total # of Events												
Synthetic Data for weather years 1980-2021												
		Duration Threshold (Hours)										
		12	**18**	**24**	**30**	**36**	**42**	**48**	**168**	**336**	**672**	**1344**	**2688**
Output Threshold (%)	**5%**	303	126	7	2	1	1	0	0	0	0	0	0
	10%	718	257	45	18	10	8	1	0	0	0	0	0
	15%	1305	441	130	48	37	27	10	0	0	0	0	0
	20%	2098	661	229	92	64	36	15	0	0	0	0	0
	25%	2998	1030	379	176	125	70	38	2	1	0	0	0
	30%	3980	1524	616	305	213	124	58	2	1	0	0	0

WIND DROUGHTS – SUMMER

Total # of Events												
Synthetic Data 1980-2021												
		Duration Threshold (Hours)										
		12	**18**	**24**	**30**	**36**	**42**	**48**	**168**	**336**	**672**	**1344**	**2688**
Output Threshold (%)	**5%**	224	90	7	3	1	1	0	0	0	0	0	0
	10%	576	225	52	20	13	10	1	0	0	0	0	0
	15%	999	349	125	52	39	25	11	0	0	0	0	0
	20%	1519	527	201	86	66	40	22	1	0	0	0	0
	25%	2094	782	345	178	128	71	34	2	1	0	0	0
	30%	2586	1150	515	276	214	131	60	2	1	0	0	0

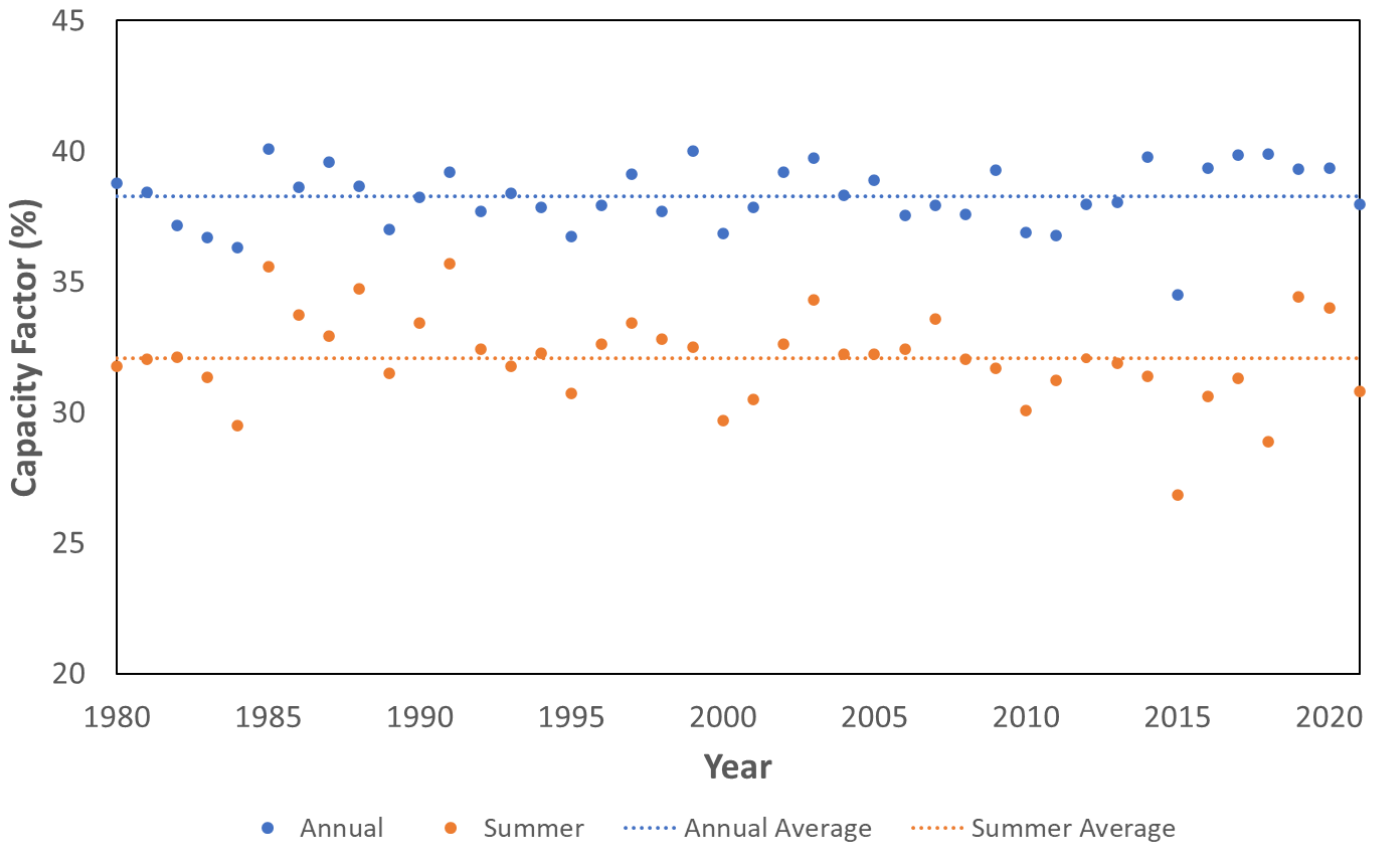
WIND DROUGHTS PER YEAR

APPROXIMATE # OF EVENTS PER YEAR												
Synthetic Data 1980-2021												
		Duration Threshold (Hours)										
		12	**18**	**24**	**30**	**36**	**42**	**48**	**168**	**336**	**672**	**1344**	**2688**
Output Threshold (%)	**5%**	8	3	0	0	0	0	0	0	0	0	0	0
	10%	19	7	1	1	0	0	0	0	0	0	0	0
	15%	35	12	4	1	1	1	0	0	0	0	0	0
	20%	56	18	6	3	2	1	1	0	0	0	0	0
	25%	81	29	11	6	4	2	1	0	0	0	0	0
	30%	106	44	18	9	7	4	2	0	0	0	0	0

WIND DROUGHTS PER YEAR – SUMMER

APPROXIMATE # OF EVENTS PER YEAR												
Synthetic Data 1980-2021												
		Duration Threshold (Hours)										
		12	**18**	**24**	**30**	**36**	**42**	**48**	**168**	**336**	**672**	**1344**	**2688**
Output Threshold (%)	**5%**	5	2	0	0	0	0	0	0	0	0	0	0
	10%	14	5	1	0	0	0	0	0	0	0	0	0
	15%	24	8	3	1	1	1	0	0	0	0	0	0
	20%	36	13	5	2	2	1	1	0	0	0	0	0
	25%	50	19	8	4	3	2	1	0	0	0	0	0
	30%	62	27	12	7	5	3	1	0	0	0	0	0

WIND CAPACITY FACTORS



Talk to us.

WIND 12X24 – ALL WEATHER YEARS

Hour of Day	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	46%	47%	46%	48%	47%	39%	35%	36%	38%	47%	53%	47%
2	46%	45%	44%	48%	46%	37%	33%	33%	37%	47%	52%	46%
3	43%	42%	40%	44%	42%	34%	29%	29%	34%	43%	47%	42%
4	43%	40%	39%	43%	40%	33%	27%	27%	33%	41%	46%	40%
5	42%	40%	38%	43%	38%	31%	24%	27%	32%	41%	45%	38%
6	42%	39%	37%	40%	36%	29%	23%	25%	30%	41%	45%	39%
7	41%	37%	36%	38%	32%	24%	18%	22%	29%	40%	44%	38%
8	40%	35%	33%	35%	30%	22%	16%	18%	25%	36%	41%	35%
9	38%	30%	30%	35%	31%	22%	16%	17%	23%	33%	36%	32%
10	35%	31%	32%	37%	31%	21%	17%	16%	23%	34%	36%	31%
11	35%	34%	34%	38%	32%	21%	17%	18%	25%	36%	39%	32%
12	35%	36%	36%	40%	34%	22%	18%	19%	27%	38%	41%	34%
13	36%	39%	37%	41%	37%	24%	19%	19%	29%	40%	43%	36%
14	36%	40%	39%	44%	40%	25%	21%	21%	30%	43%	44%	38%
15	38%	42%	42%	46%	43%	28%	24%	24%	33%	45%	46%	40%
16	40%	44%	44%	48%	46%	30%	28%	26%	35%	47%	45%	41%
17	41%	45%	44%	49%	46%	32%	31%	29%	37%	48%	47%	43%
18	44%	46%	44%	50%	47%	36%	34%	31%	39%	49%	50%	45%
19	47%	48%	45%	50%	49%	38%	35%	34%	41%	49%	51%	47%
20	48%	49%	47%	51%	50%	41%	37%	37%	43%	51%	52%	48%
21	48%	49%	47%	51%	51%	42%	38%	39%	42%	50%	53%	49%
22	48%	49%	47%	50%	50%	41%	38%	39%	40%	49%	53%	48%
23	47%	47%	47%	49%	48%	39%	37%	37%	39%	48%	53%	47%
24	44%	45%	47%	47%	46%	38%	35%	35%	37%	47%	53%	44%

PNM Talk to us. PNM.com

WIND 12X24 – DURING EUE (2025 BASE CASE)

Hour of Day	Month 1	2	3	4	5	6	7	8	9	10	11	12
	1											
	2											
	3											
	4											
	5											
	6											
	7											
	8											
	9											
	10											
	11											
	12											
	13											
	14											
	15											
	16											
	17						6%					
	18						15%	21%				
	19					21%	20%	16%		22%		
	20					27%	21%	14%				
	21					26%	22%	12%				
	22					3%	15%	0%				
	23											
	24											

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



Modeling best practices for a decarbonized future

Kailash Raman

Senior Analyst, Market Development Analytics

Form Energy

Form energy

Energy Storage
For A Better World

CONFIDENTIAL



A decarbonized future will require new grid modeling approaches

Conventional resource planning approaches are designed for *today's* grid

- A majority of installed capacity is dispatchable thermal resources
- Moderate deployment of intermittent renewables
- Limited deployment of energy storage (short-duration) for peak shaving
- 1-in-10 year extreme weather events

New resource planning approaches must be designed for the *future* grid

- Limited installed capacity of dispatchable thermal resources
- Majority of energy supply from intermittent renewables
- GW-scale deployment of energy storage (short and long durations) for flexible and firm capacity
- Increasingly frequent extreme weather events

The constant: optimizing resource portfolio to be *least-cost* and *reliable*

Form energy

© 2022 Form Energy

Modeling best practices lead to improved resource planning outcomes

Modeling Best Practices

8760 hour optimization

Multi-weather year analysis

Better representation of decarbonized grids in resource planning

Capture impacts of ***weather-driven variability*** on system

Capture increasing ***value of flexibility resources*** like energy storage

Improved resource planning outcomes

Resource portfolios better optimized in terms of cost and reliability

Form energy

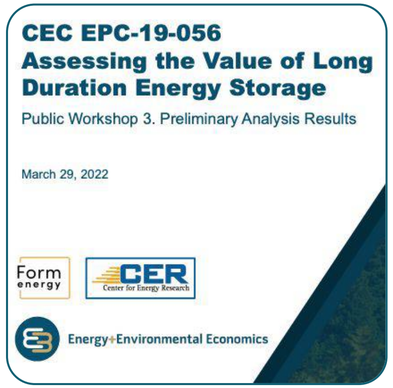
© 2022 Form Energy

PNM case study explores modeling best practices for 2040 grid

Modeling Approach

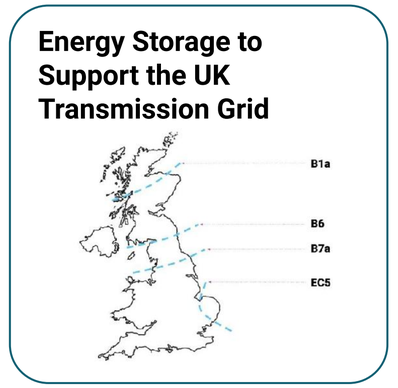
- Determined optimal, least-cost portfolios for PNM system in year 2040
- Performed modeling in Formware™, a capacity expansion and production cost model capable of 8760 hour and multi-scenario optimization
- Assessed impact of two modeling choices:
  - ***Optimization horizon:*** *the time period over which capacity expansion optimization is performed*
  - ***Weather year selection:*** *breadth of weather data captured in capacity expansion optimization*

Formware™ used in Peer Validated Studies



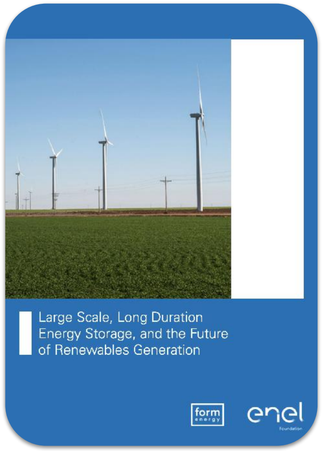
CEC-Funded Study of LDES in California

E3 + Form Energy
May 2023



National Grid ESO + Form Energy

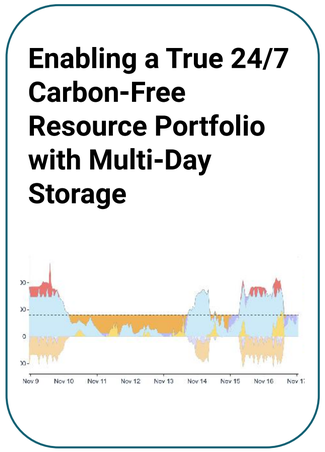
October 2021
Webpage; Tech Appendix



Long duration storage to manage wind farm risk of returns

Form Energy + Enel Foundation

2019



Great River Energy + University of Minnesota + Form Energy

April 2023

Form energy
© 2022 Form Energy

PNM case study explores modeling best practices for 2040 grid

Key Inputs and Assumptions

- Demand forecast and resource assumptions from PNM IRP public dataset
- Hourly demand and renewable profiles constructed using NASA MERRA Reanalysis Dataset for 40 historical weather years
- Assumes 0 MMT emissions in year 2040
- Model includes all candidate resources in the 2023 PNM IRP including:
  - *Solar*
  - *Wind (includes Eastern wind transmission expansion)*
  - *Li-ion*
  - *Long-duration energy storage (Flow, CAES, Thermal, Pumped Hydro, Iron-air)*
  - *Hydrogen retrofit of gas combustion turbines*
- Modeled portfolios should be viewed for directional trends rather than absolute resource requirements, given that the study did not use PNM's exact IRP inputs from the proprietary dataset

Form energy

© 2022 Form Energy

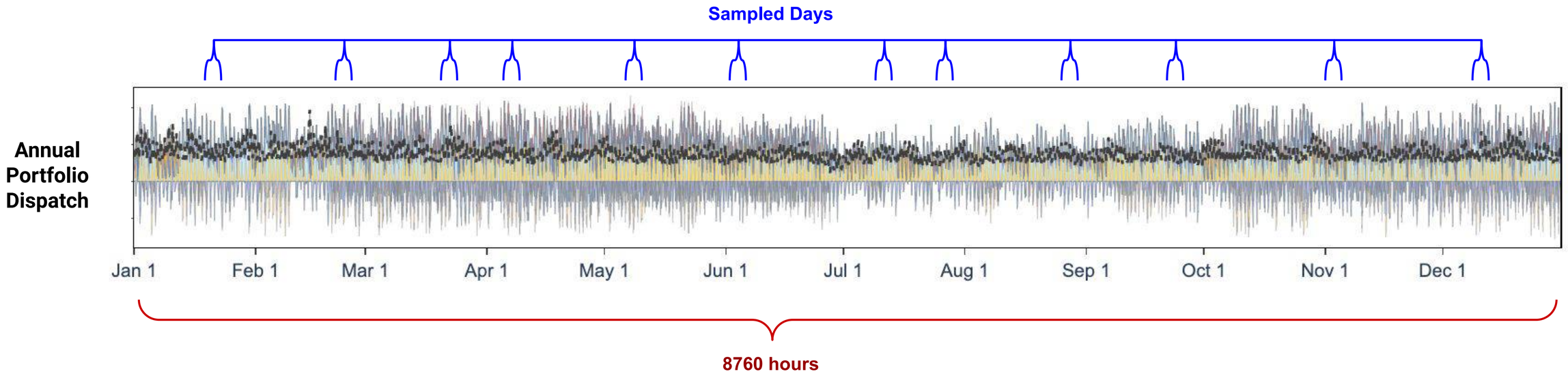
Optimization Horizon

© 2022 Form Energy

Case study investigated three optimization horizons

Optimization horizon defines the time periods over which resources are optimally built and dispatched in a least-cost capacity expansion model

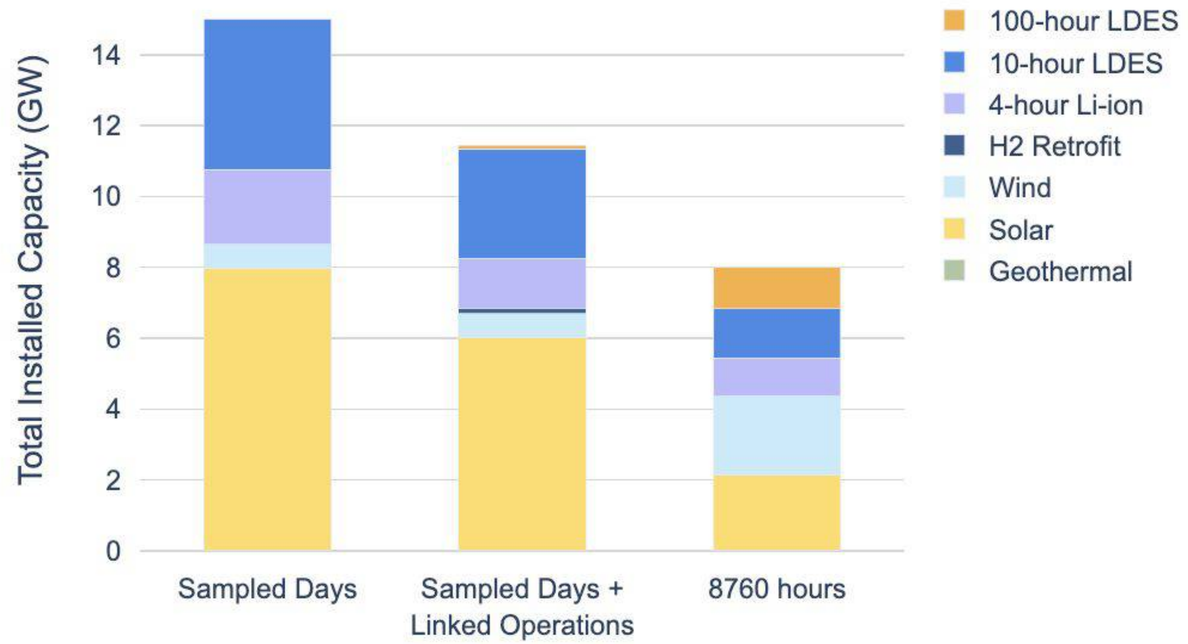
1. **Sampled days:** individually model the peak day and off-peak day of each month in the planning year
2. **Sampled days + Linked Operations:** link sampled days together to capture energy shifting by storage across multiple days/months
3. **8760 hours:** model every single hour of planning year



© 2022 Form Energy

8760 hour optimization produces most cost-optimal and reliable portfolios

Impact of Optimization Horizon on 2040 PNM least-cost portfolio



Annualized Portfolio Cost	$1.3 B/yr	$1.0 B/yr	$0.7 B/yr
Loss of Load in 8760 hr simulation	10 hours loss of load	37 hours loss of load	0 hours loss of load

- Least-cost portfolios were optimized based on 2021 weather year
- Resulting portfolios were dispatched over all 8760 hours of this weather year to assess loss of load
- 8760 hour optimization produces most optimal resource portfolio in terms of cost, reliability, and resource build
- Sampled days methods may not fully capture the value of long-duration energy storage (LDES)
- Renewable build requirements significantly decrease when LDES operations are accurately captured

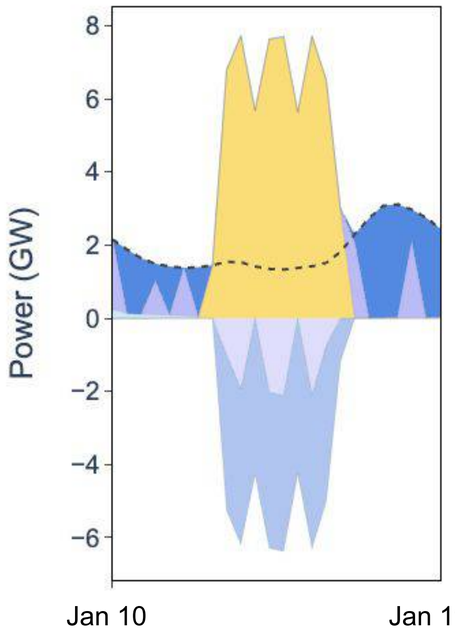
Form energy

© 2022 Form Energy

8760 hour modeling captures full range of weather variability

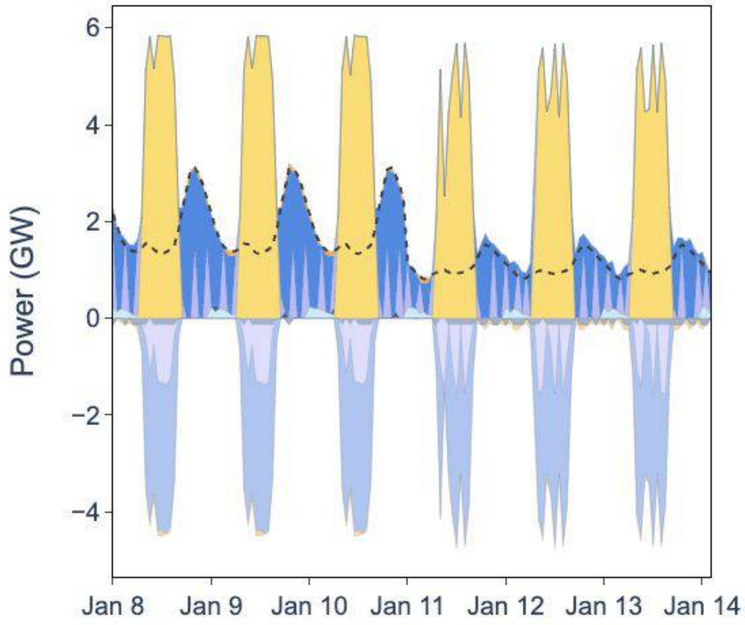
Portfolio optimization and dispatch over January week

January Sampled Day



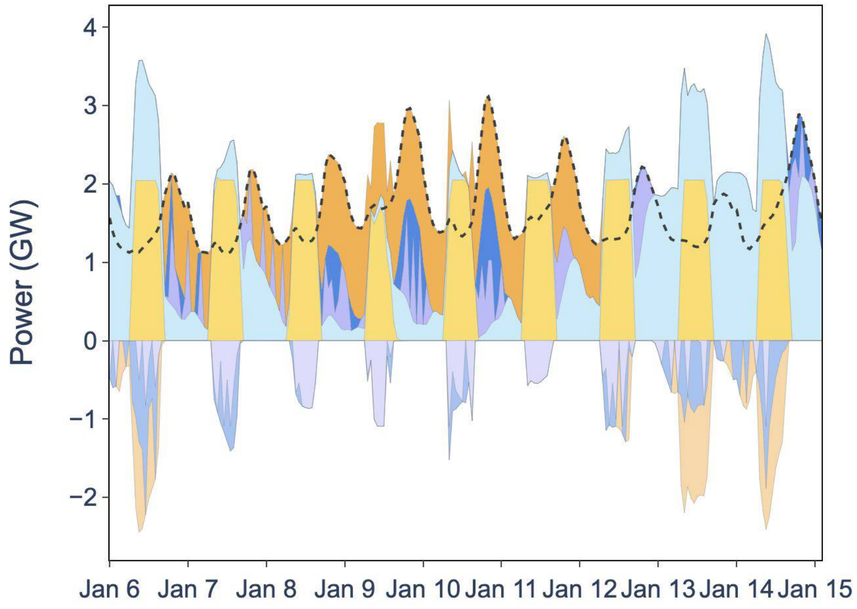
Captures only one day of weather patterns

January Sampled Days Linked



Captures only 1-2 days of weather patterns

8760 hr Representation



Captures hourly variation in load and renewable shapes during wind lull



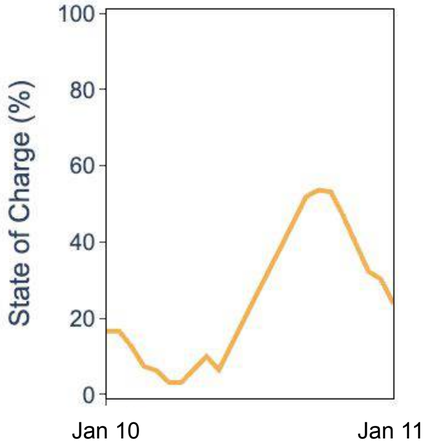
Form energy

© 2022 Form Energy

8760 hour modeling captures full value of energy storage to the grid

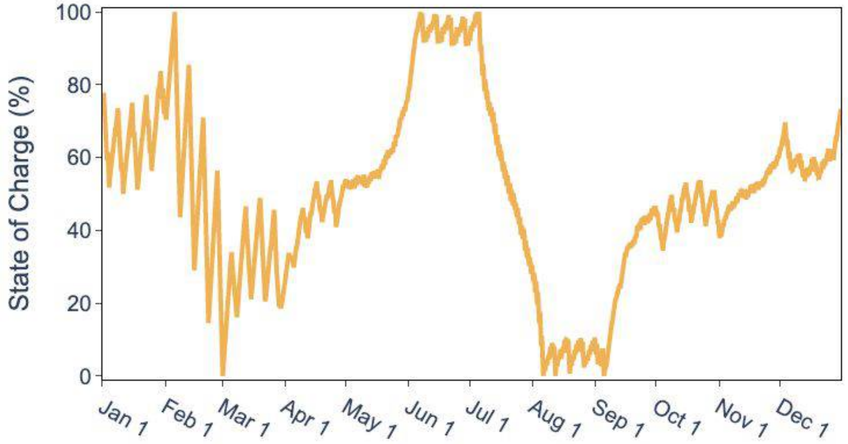
LDES State of Charge over Optimization Horizon

Sampled Day



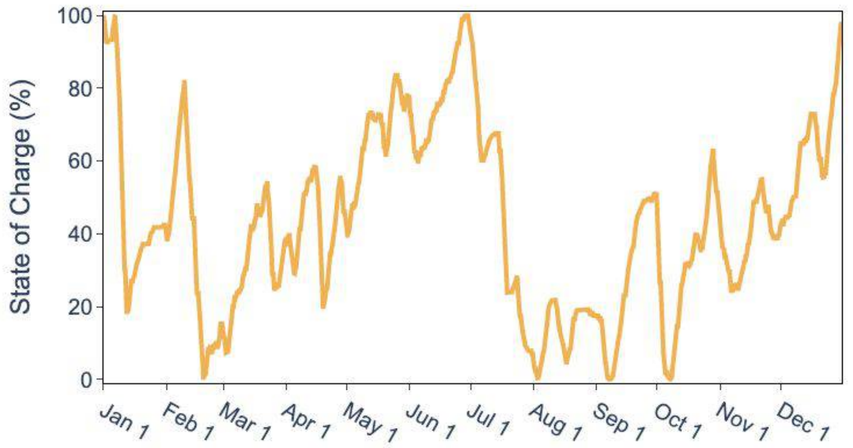
Minimal LDES operations

Sampled Days Linked



Some seasonal energy shifting

8760 hr Representation



Energy shifting on daily, weekly, monthly, and seasonal time scales

Form energy

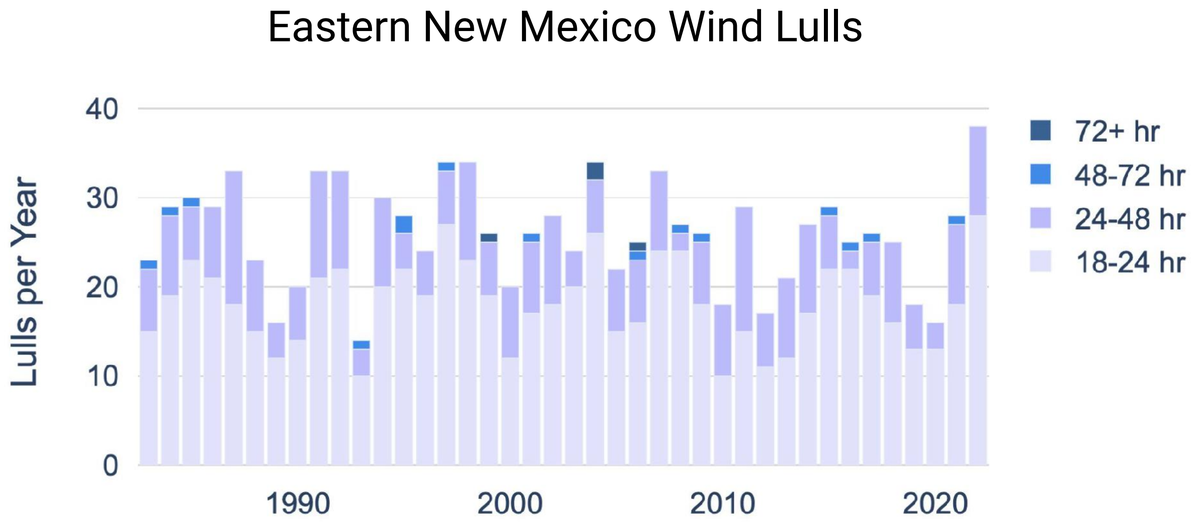
© 2022 Form Energy

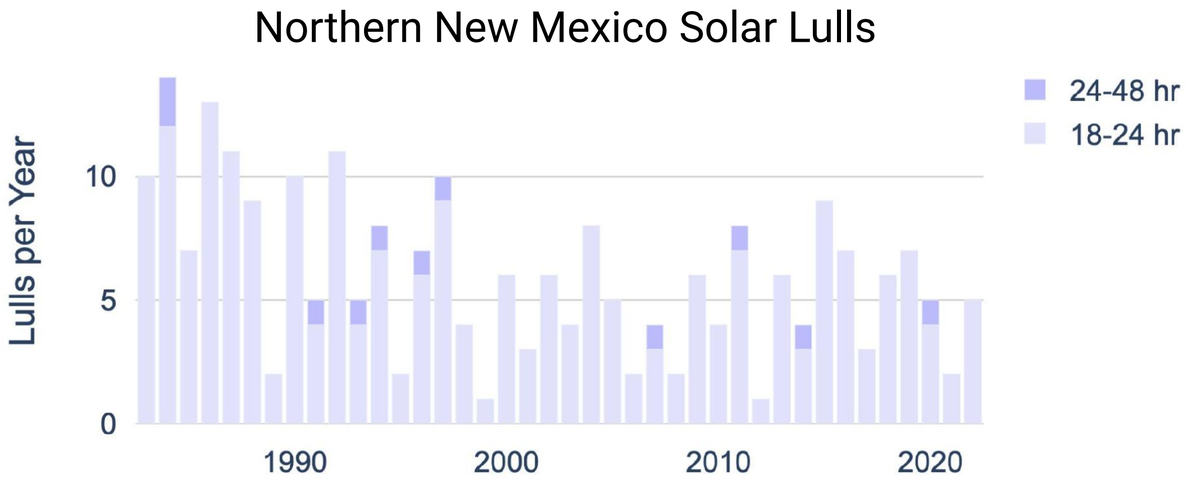
Weather Year Selection

© 2022 Form Energy

Case study investigated the impact of weather year selection on portfolio optimization

- Weather varies from year to year, driving changes in load and renewable generation profiles:
  - *Renewable lulls*
  - *Extreme weather events*
- Modeling multiple weather years can ensure that portfolio is robust against a wide range of weather conditions
- We performed least-cost portfolio optimization on 40 historical weather years, across all 8760 hours in each year

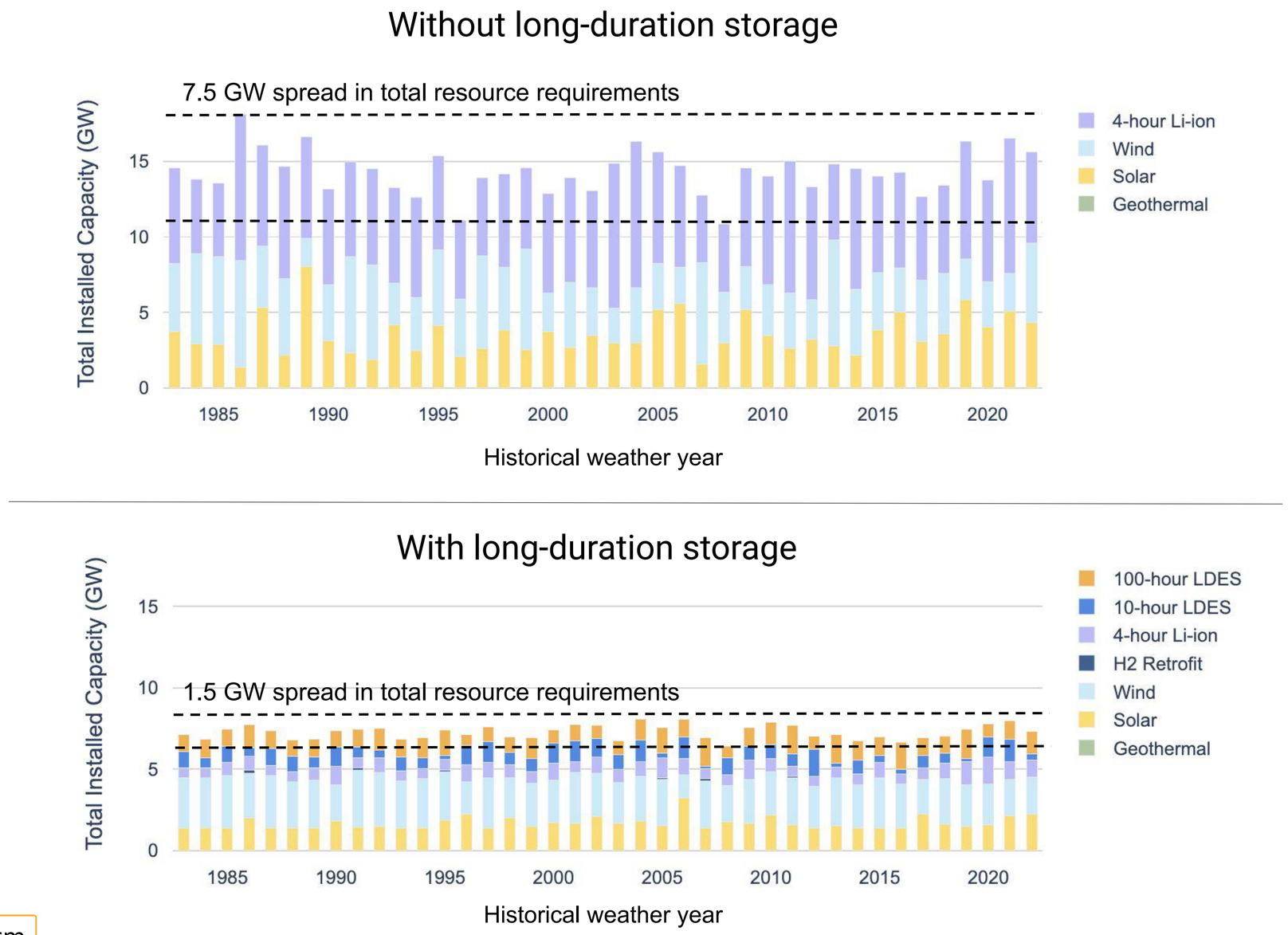




Lulls defined as continuous periods with capacity factor less than 50% of average annual capacity factor

Form energy
© 2022 Form Energy

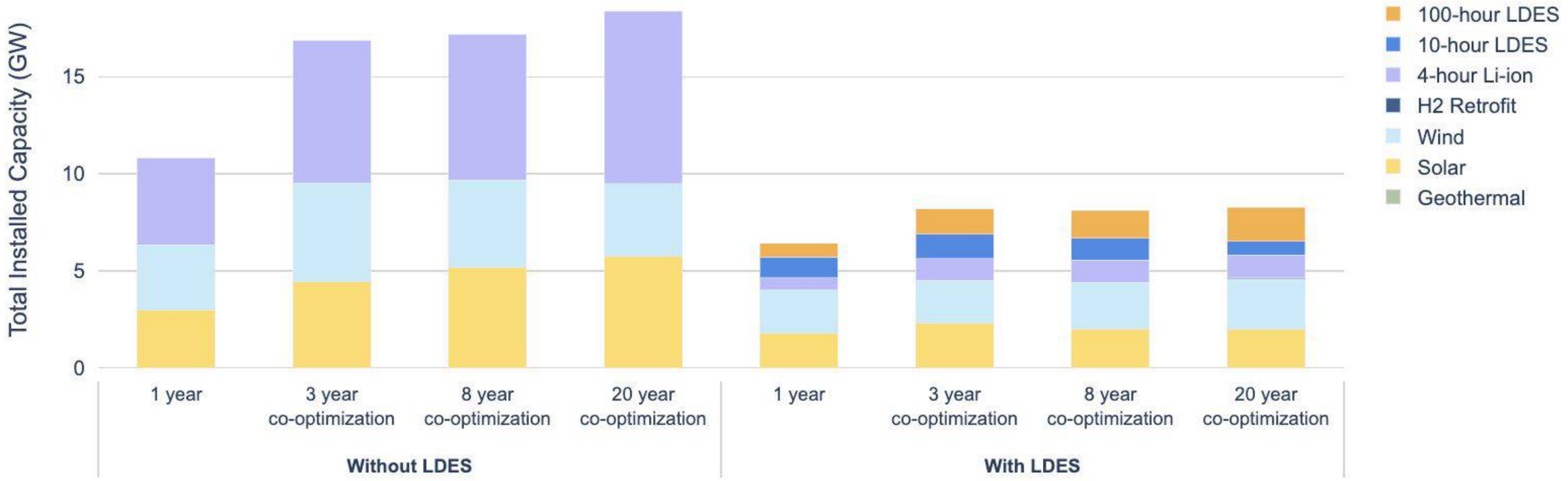
Modeling a wide range of weather years is critical to capturing resource variability



- Resource requirements vary dramatically across weather years
- Modeling a wide range of weather years helps to ensure that portfolio can maintain reliability across a diverse set of weather conditions
- Sensitivity of portfolios to variation in weather years was found to be higher in portfolios without LDES than portfolios which include LDES

Form energy
© 2022 Form Energy

Co-optimization across multiple weather years can account for year-to-year weather variation



© 2022 Form Energy

Conclusions

© 2022 Form Energy

Future IRP methods must evolve for a decarbonized grid

- Resource planning in a decarbonized future will require capacity expansion modeling approaches that more accurately capture weather variability and value of flexibility resources
- New capacity expansion methods must be designed to be compatible with the integrated resource planning process
  - *Integrating new optimization methods may require modeling tradeoffs in order to maintain computational feasibility*
- PNM case study identified two modeling best practices:
  - *Implementing an **8760 hour optimization** horizon results in the most optimal portfolios in terms of cost and reliability*
  - ***Multi-weather year analysis** can ensure portfolio robustness across a wide range of weather conditions*

Form energy

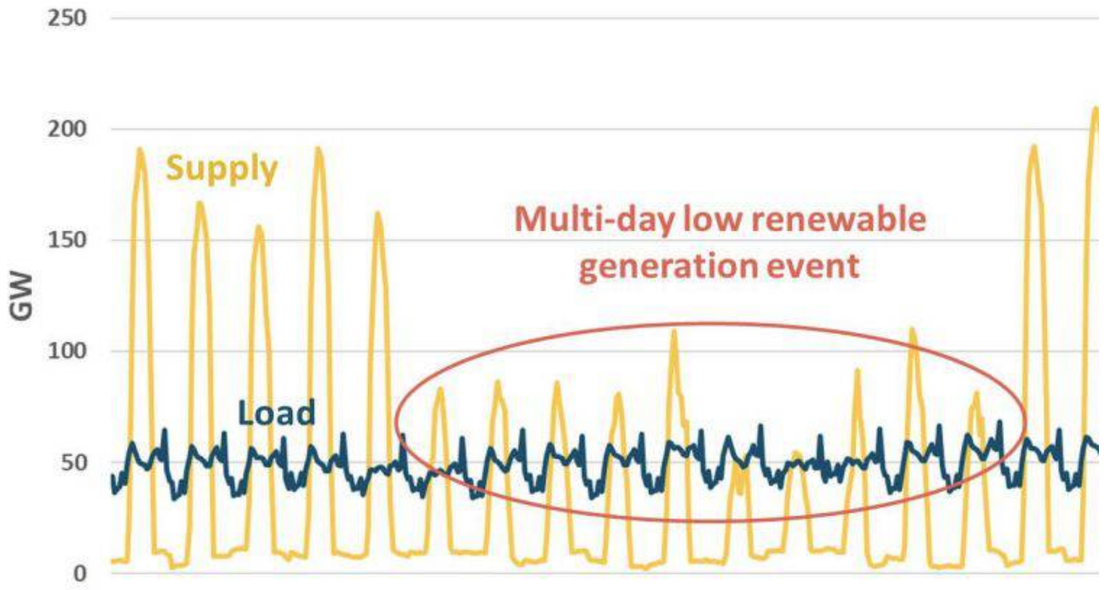
© 2022 Form Energy

Appendix

© 2022 Form Energy

Future resource planning must capture weather variability

Multi-day weather events will drive reliability challenges in a decarbonized future grid



California multi-day weather event

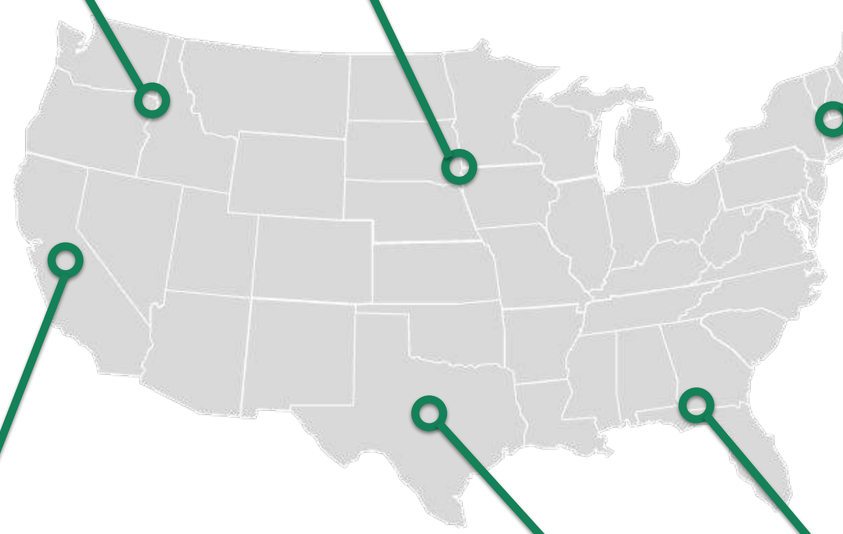
Source: E3: Long-Run Resource Adequacy Under Deep Decarbonization

Weather-related reliability risks have been identified in nearly every major power market

Pacific Northwest
E3 modeled multi-day renewable lull during drought years

Upper Midwest:
Xcel Energy multi-day wind lull during cold winter in 2019

New England:
DNV-GL suggests as many as 2 wind lulls ≥3 days during heat waves per year

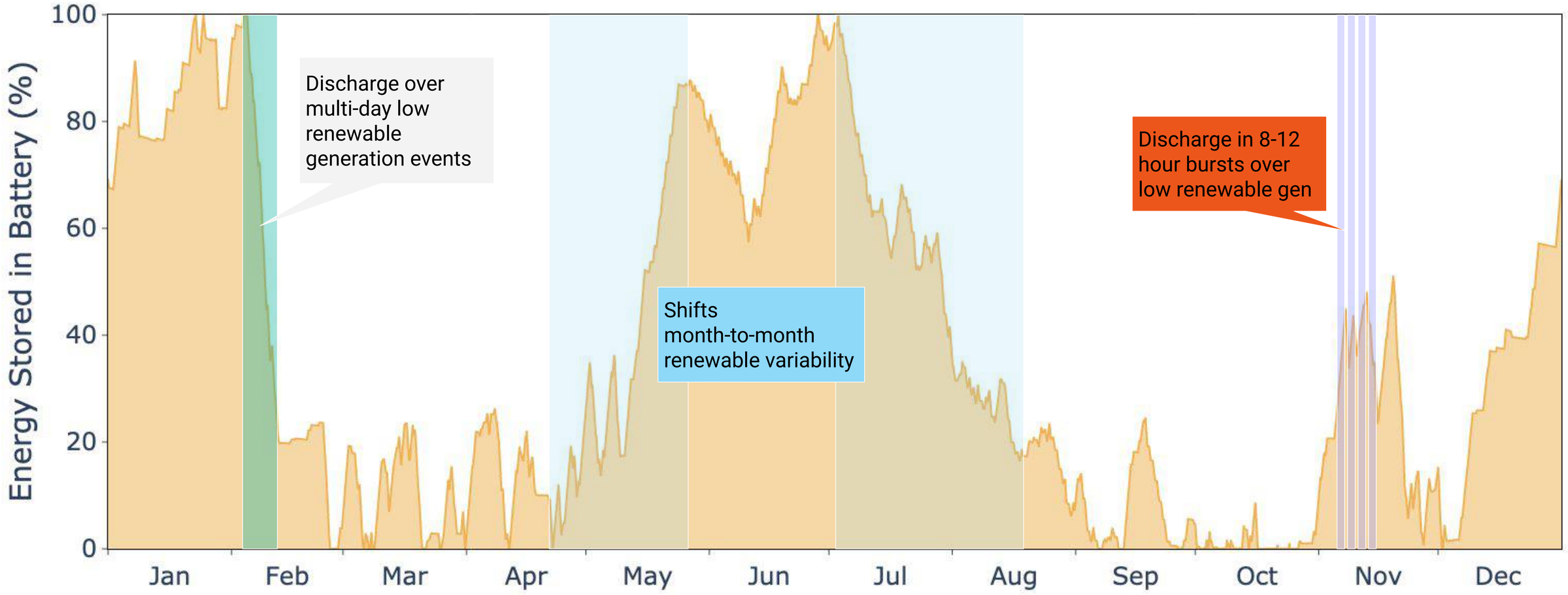


California
E3 modeled 10 day undersupply during cloudy week in 2050

Texas
Winter Storm Uri forces 3 days of load shedding in 2021

Southeast
FP&L adopts to winter peak planning to avoid up to 13M customer outages

Future resource planning must capture 8760 hour energy storage dynamics



Multi-Day

Seasonal Up
(net charge with excess renewables)

Seasonal Down
(net discharge during peak load season)

Intra-Day

Integrated Resource Plan: Statement of Need
June 26, 2023 Draft

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction
    a. The PNM Integrated Resource Plan 2023 provides a comprehensive long range path for building out the strongest, most reliable electrical power delivery system for our customers over the next 20 years as we can envision. The IRP report begins with the current status of PNM's system, and shows how available resources and technologies can bring improvements. Simultaneously we recognize that changes are occurring in nearly every sector of the environment in which we operate. These will require ongoing re-evaluation and modifications to the 2023 IRP plan that will be incorporated in future triennial PNM IRPs.

       Meeting our clean energy goals and preserving system reliability, while providing for the growing needs of our customers in an affordable manner, will require the addition of significant amounts of new generation capacity over the next twenty years. We anticipate that between today and 2040, the likely amount of new installed generation capacity will total between 4,000 to 5,000 MW or more. This amount of *new* capacity is significantly greater than the amount that exists today, implying that the achievement of our goals will require continuous and significant evolution of our portfolio.

       This IRP does not represent a future system design or even a pathway to a full system design for the PNM planned 2040 zero carbon grid. The action plan, dictated in the IRP rules, only provides a 3-year detailed plan and thus any identified resources past 2027 are currently speculative. The limited timeframe of an action plan may well serve a semi-static resource portfolio with a highly predictive load profile, but the addition of a State clean energy policy requirements, which requires a massive rebuild of the entire 100-year-old system, may require a more defined and longer-term action plan to initiate actual projects toward building out the final solution. Given the buildout of long duration energy storage and other zero carbon dispatchable power generation could take decades and cost tens of billions of dollars, an IRP that can only speculate on this future is insufficient for determining the most reliable and affordable system, that can be initiated today, to meet the operational needs of the grid a mere 16-years from now.

2. Vision and Goals
    a. The identification of a set of resources and a sequencing of those resource deployments that conforms to the regulations and policies of the State of New Mexico, reliably serves all customers at a reasonable cost with electrical energy that is that is resilient in the face of national security, technology, infrastructure, resource, cyber and environmental constraints.
    b. Goals
        i. Reliability and Resiliency: Utility's Obligation to Serve
            1. Minimum Reserve Requirements
            2. Reliability Standards
            3. Swift recovery from climate or cyber disruption
        ii. Public Interest and Equity
            1. Responsibilities to Ratepayers and Shareholders
                a. Affordability
                b. Availability to Underserved Communities
                c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
            2. Costs associated with the development and deployment of all candidate resources
                a. Costs of Energy to Consumers
                b. Climate Change Impacts
                c. Life Cycle Impacts (Recycling/disposal)
                    i. Greenhouse Gas emissions
                    ii. Materials
                    iii. Utility Disposal
            3. Consumer Education
            4. NIMBY
3. Identified Decision Points and Pathways
    a. "Getting to Zero" Carbon
        i. Motivations
            1. Regulations & Policy
                a. ETA (2019)
                    i. EPA - evolving
            2. Public Service in response to Mar 2023 IPCC report analysis - https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23
    b. Making "no regrets" decisions
        i. Minimizing investment risk
            1. Stranded assets
                a. Loss of public trust
        ii. Maximizing investment opportunity
            1. First to market w/ long term solutions
            2. Public trust and sentiment
        iii. Value of money vs future human life opportunities
    c. Regional Planning and Coordination
        i. Organized Market Opportunities
        ii. Future Regional Transmission Operator

4. Resources

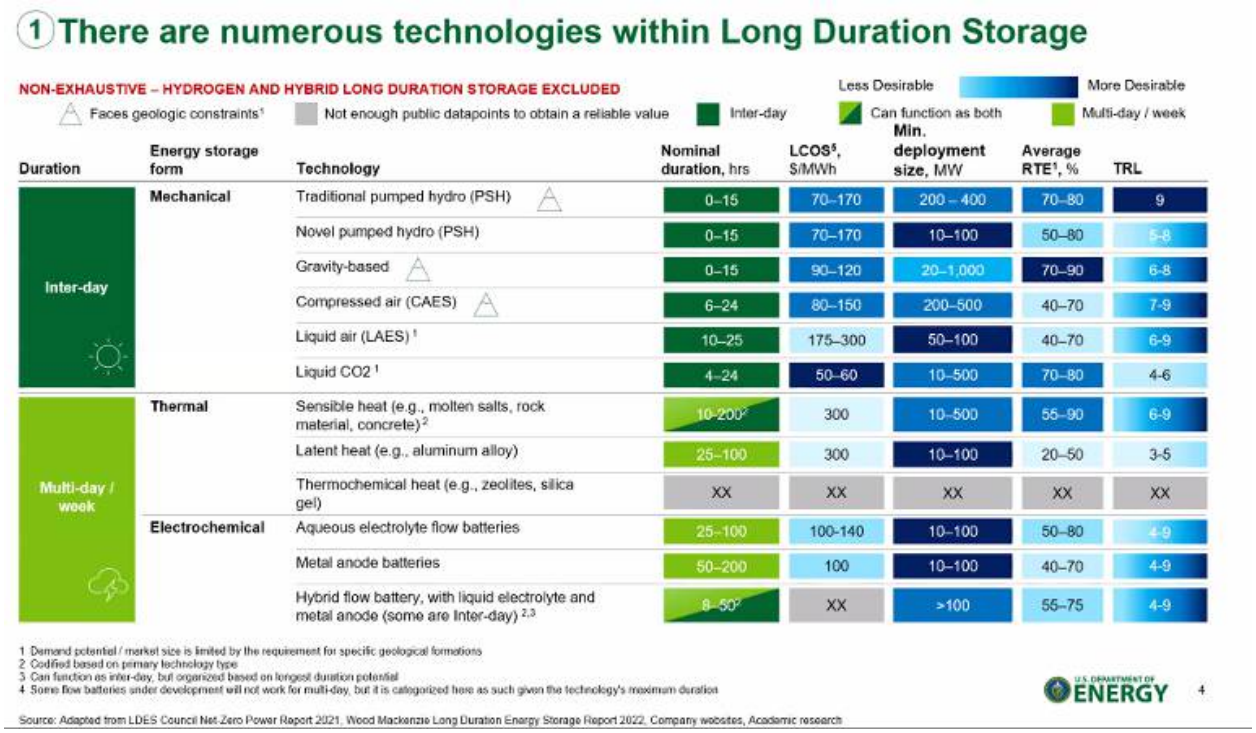
   a. Candidate Resources
      i. Renewable generation
         1. Solar (including community solar)
         2. Wind
         3. Geothermal
   b. No new gas of any type
   c. Energy Storage
      i. Short duration (up to 10 hr)
         1. Lithium-ion battery etc. (see below charts)
      ii. Inter-day & Multi-day/week Long Duration Energy Storage (LDES) – (see charts below)
      iii. Seasonal Shifting
         1. Pumped-hydro storage, thermal energy storage, etc
   d. Not for electric
5. Potential New Resources
   a. Adoption of new technologies
   b. High Penetration of Distributed/Customer-owned Generation
   c. Firming Plans
   d. Energy efficiency and demand-response
   e. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
6. Preferred Portfolio
   a. [results of PNM modeling]
   b. Potential pilot projects
   c. [PNM conclusions]

ADDITIONAL MATERIAL

Resource Description:
A *brief* description of the resource; its technical characteristics.

Commercial Maturity:
The TRL level or similar metric to describe the commercial maturity of the resource. How long has it been used in electric utility applications? This criteria needs to be done carefully. Some technologies have been the brunt of sabotage, business ineptness, and smear campaigns by the opponents.

Staged Cost:
This is a breakdown of cost by scale (if applicable). For example, solar may have a cost for 1 MW to 5 MW; and a different cost for 10 MW to 100 MW. And for storage it should also include RTE and similar variables as are in the below table.



1 There are numerous technologies within Long Duration Storage

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDED

Less Desirable — More Desirable

△ Faces geologic constraints[1] | Not enough public datapoints to obtain a reliable value | 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[1], %	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 CO2[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[3]	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[4]	XX	>100	55–75	4-9

1 Demand potential / market size is limited by the requirement for specific geological formations
2 Codified based on primary technology type
3 Can function as inter-day, but organized based on longest duration potential
4 Some flow batteries under development will not work for multi-day, but it is categorized here as such given the technology's maximum duration

U.S. DEPARTMENT OF ENERGY 4

Source: Adapted from LDES Council Net-Zero Power Report 2021, Wood Mackenzie Long Duration Energy Storage Report 2022, Company websites, Academic research

Grid Applications and Benefits:
Why is this resource important to the grid? What are its applications and benefits?

IRP Rule, Appendix A, "Determination of the Resource Portfolio"

DETERMINATION OF THE RESOURCE PORTFOLIO:

A. To identify the most cost-effective resource portfolio, utilities shall evaluate all supply- side resources, energy storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.

B. The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.

C. The utility shall consider and describe ways to mitigate ratepayer risk.

D. Each electric utility shall provide a summary of how the following factors were considered in, or affected,
the development of resource portfolios:

(1) load management or modification and energy efficiency requirements;
(2) renewable energy portfolio requirements;
(3) existing and anticipated environmental laws and regulations, and, if determined by the commission, the
standardized cost of carbon emissions;
(4) fuel diversity;
(5) susceptibility to fuel interdependencies;
(6) transmission or distribution constraints; and
(7) system reliability and planning reserve margin requirements.

E. Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.

PNM IRP Stakeholder Process - SoN

Parking Lot

What describes end-of-life? For example, batteries may have an end-of-life when they can deliver only 70% of
their nameplate capacity.
How is the resource disposed of at the end of its operational life?
Two resources that need to be included are Geothermal and Small Modular Reactors (SMR)>Small Modular
Reactors go against the ETA requirement that 100% of IOU generation sources be renewable by…2045 or
2050. NM has been abused by the nuclear industry from cradle to grave. In addition, Germany has rightly
retired its last 3 nuclear power plants this year recalling that 3 generations of use is now resulting in 30,000
generations of oversight of its waste. No thank you.
And again any new gas must be excluded. Methane is 85x more potent GHG than CO2 over 20 yrs, but
because it exits the cycle within 12 yrs, it should be counted in the short term as 150-200x more potent.
Energy Efficiency
● PNM already offers a robust energy efficiency portfolio.
o The IRP should reflect that existing effort, likely as a load forecast modifier. However, there is incremental energy efficiency to gain in PNM's territory.
● PNM has developed bundles of energy efficiency measures which can be selected by the IRP models.
oThese bundles are quite comprehensive but additional details are needed around cost assumptions and omitted technologies.
oPNM should provide insight into the energy efficiency IRP selections by sector, technology, and cost.
Demand Response
● Another DSM area in which PNM has existing resources.
● This should be taken into account in the load forecast.
● PNM should identify new, incremental demand response that can be selected as a resource in the IRP
model.
Load management
● Include time of use rates and other dynamic rate options.
● Should be modeled in any IRP efforts.
● A well-designed dynamic rate can change the load profile of customers and therefore the resources

needed to meet demand in any given hour or day of the year.
● Different load shifting and adoption scenarios should be run
What are grid improvements needed for DSM to be quantifiably be included in the IRP?
● Assuming PNM receives approval in case 22-00058-UT, then the grid improvements needed to measure
DSM impacts for accurate quantification will be coming online over the next few years.
● PNM does not have the visibility in the existing grid to effectively use DSM as a time and location based
resource at this time.
How will PNM's programs such as Whole House Electric Vehicle (WHEV) rate impact DSM?

7
Will low-income customers get price incentives with smart meters?[1] And you should make the program
voluntary, as there are real concerns for increased electromagnetic wave generation. Beyond the IRP
discussion in my opinion. These issues are better for the energy efficiency filing.
As for comments and updates I don't have much to add right now but I do think an explanation of
what an IRP is and isn't should be part of this effort. I say this because, as we have marched through this process, I have started to learn that since the Action Plan is only a 3-year look ahead,
the rest of the IRP 20-year window is effectively, speculation. I originally had the false assumption
that an IRP was essentially a Utility's capital outlay plan that looked out 20 years, but now I realize
that is not the case.
Unfortunately, when we are looking to the utilities to clearly define and start initiating their planned
buildout for the Energy Transition, the IRP is not the tool. I think that should be highlighted so the
public knows the IRP is not a fully transparent window into the future.
A previous version of the SoN identified 13 potential resources and now it's been cut to three with the
elimination of any types of gas. All options should be left on the table as it is too early to eliminate any
while PNM is making the transition from carbon-based energy to other forms of energy. Options, including current energy sources, should be prioritized based on feasibility of the available technology,
required infrastructure, reliability, and environmental & social costs (lifecycle costs). - Robert Barber

● Need to pull out section on consumer education and NIMBY and make it higher profile (she has

made this comment in several meetings)
Fengu – include impacts on electrification on load forecast
● Ensure new capabilities of wind turbines is taken into account in modeling
● (Margie – should these be added to modeling questions?)
Jim REIA – need to include more information on distribution system planning into IRP process.
Cliff – (in SoN or somewhere) add recommendation that PNM increase its data collection on outages on
the distribution system, specifically calling out outages in disadvantaged areas.
From Ho, Clifford Heinrich in the chat ---
Sorry, meant to send this earlier during our discussion of the Statement of Need: With regard to my comment on distribution system reliability, I believe that a discussion of how the collection, use, and dissemination of reliability data (SAIDI, SAIFI, MAIFI, CAIDI) can be (or is being) used to
improve the reliability of both distributed and centralized energy resources on an ongoing basis (as feedback and validation for modeling and planning) may be beneficial. I believe these data, if
reported on a sufficiently granular level, can also be used to inform equity (e.g., are disadvantaged communities receiving the same power reliability as other communities, especially with the rapid growth of distributed energy resources?).
ARCHIVED SECTIONS

8

a. Regulatory Environment and Requirements
i. Legal requirements and standards in planning horizon
1. Energy Transition Act
a. Renewable Energy Act / Renewable Portfolio Standard
i. 80% renewable by 2040 and 100% carbon-free by 2045
b. Status of plant abandonment and replacement power
2. Efficient Use of Energy Act
a. Energy efficiency and load management goals starting in 2025/6
3. EPA GHG Standards for fossil-fueld power plants
a. Proposed 5/23/23, may take 1 year or longer to finalize
b. Starting in 2030, the proposed requirements vary by the type of unit (new or existing, combustion turbine or utility boiler, coal-fired or natural gas-fired), how frequently it operates, and its operating horizon (i.e., planned operation after certain future dates).

4. EPA Good Neighbor Plan
a. NOx emissions trading regime for power plants in 22 states
b. March 15, 2023 plan did not include New Mexico but said “EPA’s updated modeling analysis for 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico, may be significantly contributing to nonattainment or maintenance in downwind sites.

EPA intends to undertake additional assessment of its modeling for these states and will determine if it is necessary to address Good Neighbor obligations for these states in future action(s).”

ii. Known and expected rules
1. NM Stat § 62-17-10 (2018)
2. NM Administrative Code 17.7.3
3. Case #21-00128-UT Final Order
a. Substantial revisions to NMAC 17.7.3 IRP planning rule, of which this Statement of Need is a part.
i. IRP filing and content requirements
ii. description of existing resources,(2) current load forecast, (3) load and resources table, (4) identification of resource options, (5) statement of need, (6) determination of the resource portfolio, and (7) action plan,
iii. Facilitated Stakeholder Process; IRP Process
iv. Statement of Need
v. Action Plan
1. June 2 PRC letter re: Action Plan period and planning horizon

vi. Request for Proposals Process, Cost recovery, Independent Monitor, Variances and Amendments
4. Case #21-00033-UT(PNM 2021 IRP) Final Order
a. “23. For this reason, the Commission finds that PNM should include, in its future 2023 IRP filing a meaningful analysis of transmission and distribution constraints and opportunities to increase resource availability and flexibility.”

9
b. Additional requirements/orders added since #21-00128-UT Final Order?

Statement of Need Input from June 29 Stakeholder Meeting

Introduction

- Avoid conclusory statements “provides the strongest’. Instead use “goal” “target” “aims to achieve” language.
- Change resiliency to resilience.
- Section b part I, 3, should include “security”, “etc” = other potential threats
- Identify key interim dates for emission reduction targets.
- Paragraph 3 – State that the modeling should provide an initial perspective on resource pathways to achieve a zero carbon grid by 2040.
- Section A, sentence 1 and paragraph 3 need to be reconciled.
- Sentence 2 in paragraph 3 is more aligned with what this plan provides.

Vision & Goals

- ii, 2, b. add “pollution” to Climate Change Impact.
- How will planning reserve margin apply vs. LOLP by portfolio?
- Either avoid concepts that cannot be quantified in modeling, scenarios or scoring of bids – or identify some concepts as only conceptual or external to the modeling/RFP process.
- Replace “life cycle impacts” with “extraction, use and disposal” not just recycling/disposal.

Decision Points and Pathways

- Community education – Not education but need for a consistent reliable, perhaps “neutral” source of information on the process of moving off fossil fuels with centralized power generation into a world of multiple source generation need electricity demand. Doing all this while PNM continues to serve customers reliability.
- Will stakeholders and PRC be evaluating solicitation bid documents and bid scoring plan?
- Why is “maximizing investment opportunity” a goal? For whom? How about maximizing competitive RFP opportunities, fair competition and evaluation of bids?
- Add evaluation of the land use and community impacts.
- Identify interim and 2040 key emission reduction dates.
- Tradeoffs between zero carbon grid and ability to respond to catastrophic events.
- Unintended consequences/negative impacts of 2040 zero carbon grid.

Resources

- Fix, define or delete “not for electric”
- Summarize the primary scenarios and sensitivities considered prior to the selection of the preferred portfolio.
- Include a table of the MW and $ associated with those scenarios.
- Provide a summary of the load impacts for the preferred portfolio (e.g., TOU, DERs, EE).

Potential New Resources

- Avoid prescribing specific resource acquisitions by MW or type, or tech-specific RFP. Instead rely on actual bids in an all-source RFP.
- What are the differences between “candidate resource” and “potential new resources”?
- What does “no new gas of any kind” mean? No new natural gas? Or nothing other in gaseous form? (Note: only referring to natural gas)
- Statement of need should come after PNM discusses candidate resources and description of modeling.

Additional Comments

- I am concerned that part of the SoN need document that was shown and passed out, was removed, because it was assumed that PNM was exclusively qualitied in this area (statement of condition). How was this assumption made? It also removes the thoughts of other IRP stakeholders in this area.
- How are objectives handled?
- How will scenarios generated?
- How planning horizon is determined

GRIDWORKS

PNM Integrated Resource Plan: Stakeholder Meeting #7
July 27, 2023 | 9:00am - 12noon MDT

AGENDA

9:00 AM – Welcome, Purpose, Outcomes for the Day, & Schedule Update, Gridworks

9:10 AM – Results from Most Recent RFP, PNM

9:25 AM – Modeling Results to Date, PNM Team and Gridworks

Modeling Core Team facilitated Q&A session, focused on understanding results to date

All participants will have access to chat for submitting questions, MCT will prioritize questions

10:40 AM – Break

10:50 AM – Statement of Need Input Consensus and Stakeholder Priority Needs Worksheet, Michael Barrio and Gridworks

11:45 AM – Summary of Actions and Next Steps, Meeting Feedback

12:00 NOON – Adjourn

Welcome!

Stakeholder Engagement Meeting
(Meeting #7)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, July 27
9:00 AM – 12 NOON Mountain Daylight Time

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Materials available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose and Outcomes of Today's Meeting

Prepare stakeholders to provide input to the Action Plan in August.

KEY OUTCOMES

- Stakeholder understanding of modeling results to date
- Review status of input to Statement of Need
- Stakeholder priority needs of most cost effective portfolio

Agenda

9:00 AM – Welcome, Purpose, Outcomes for the Day, & Schedule Update, Gridworks

9:10 AM – Results from Most Recent RFP, PNM

9:25 AM – Modeling Results to Date, PNM Team and Gridworks

- Modeling Core Team facilitated Q&A session, focused on understanding results to date
- All participants will have access to chat for submitting questions, MCT will prioritize questions

10:40 AM – Break

10:50 AM – Statement of Need Input Status and Stakeholder Priority Needs Survey Results, Michael Barrio and Gridworks

11:45 AM – Summary of Actions and Next Steps, Meeting Feedback

12:00 NOON – Adjourn

We are Preparing to Develop Input to the Action Plan

March – May | June – August | Sept – Nov | IRP Filing Dec. 15

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

SCHEDULED MEETINGS

- **Aug. 31, 8:30 AM – 12:30 PM** – Review results of R&R analysis. Draft input for Action Plan
- Sept. 14, 9 AM – 10:30 AM – Finalize stakeholder input to Action Plan
- Oct. 19, 9 AM – 10:30 AM – Review IRP elements of greatest interest to stakeholders
- Dec. 19, 9 AM – 10:30 AM – Facilitated Stakeholder Process feedback collection

NOTE: August 17 meeting is moved to August 31 from 8:30 AM – 12:30 PM

Modeling Result to Date Discussion

- PNM Team presentation, 45 minutes
- Modeling Core Team facilitated Q&A, 30 minutes
  - Focus is to create understanding of results to date
  - All attendees can submit questions via chat
  - Modeling Core Team will prioritize and pose questions

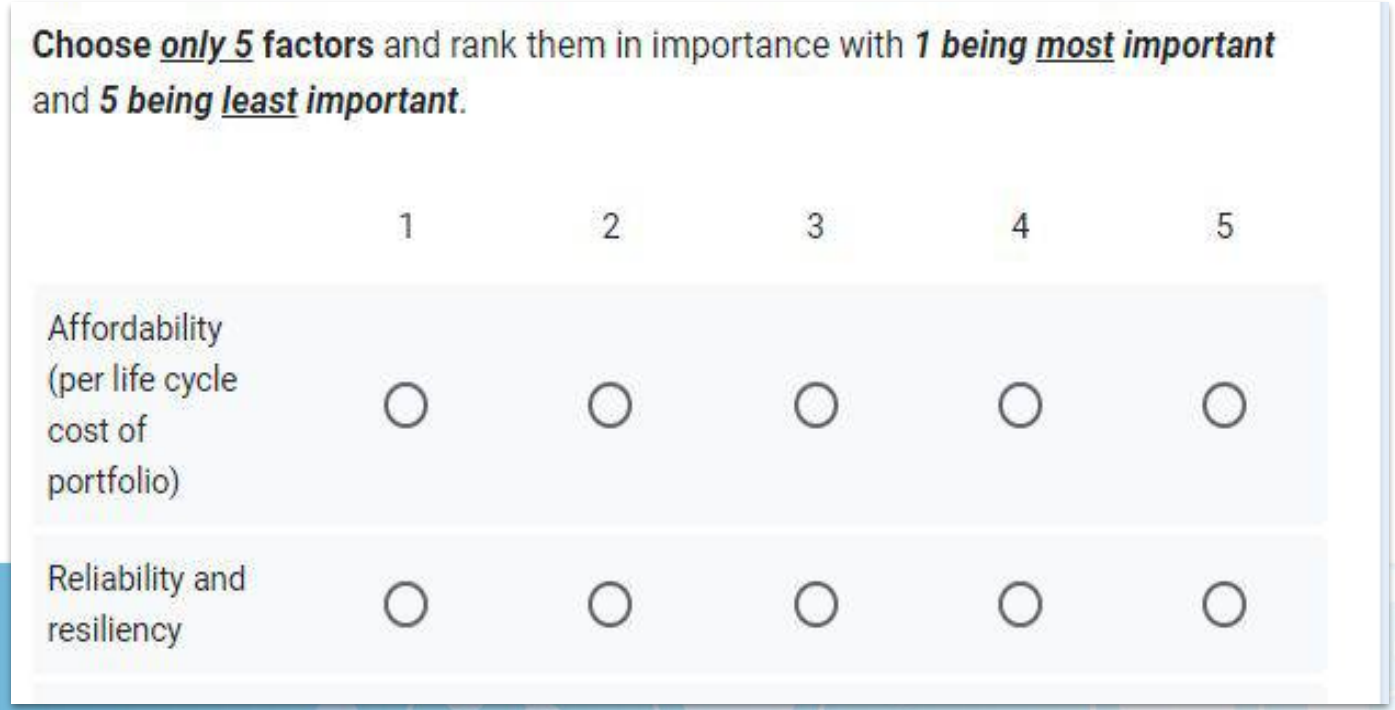
Modeling Results to Date

PNM TEAM

GRIDWORKS

Statement of Need and Stakeholder Priority Needs

- Update on SoN Input document - Michael Barrio
- Stakeholder priority needs worksheet: https://forms.gle/vBfqBtjpqJdNfcza7
- Discussion
- Complete worksheet
- Review results



Choose *only 5* factors and rank them in importance with ***1 being most important*** and ***5 being least important***.

	1	2	3	4	5
Affordability (per life cycle cost of portfolio)	○	○	○	○	○
Reliability and resiliency	○	○	○	○	○

Priority Needs/Factors Input to Date

Add graph of results as of 7/24

Summary
Next Steps
Meeting Survey

Next Meeting is August 31 (changed from August 17)

March – May | June – August | Sept – Nov

IRP Filing Dec. 15

1: Grounding and Statement of Need

2: Model Runs and Produce Action Plans

3: IRP Reviews

SCHEDULED MEETINGS

- Aug. 31, 8:30 AM – 12:30 PM – Review results of R&R analysis. Draft input for Action Plan. Modeling insights from a stakeholder will be presented.
- Sept. 14, 9 AM – 10:30 AM – Finalize stakeholder input to Action Plan
- Oct. 19, 9 AM – 10:30 AM – Review IRP elements of greatest interest to stakeholders
- Dec. 19, 9 AM – 10:30 AM – Facilitated Stakeholder Process feedback collection

NOTE: August 17 meeting is moved to August 31 from 8:30 AM – 12:30 PM

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

PNM 2023-2042 IRP: Modeling Results Update

FACILITATED STAKEHOLDER MEETING

JUL 27, 2023

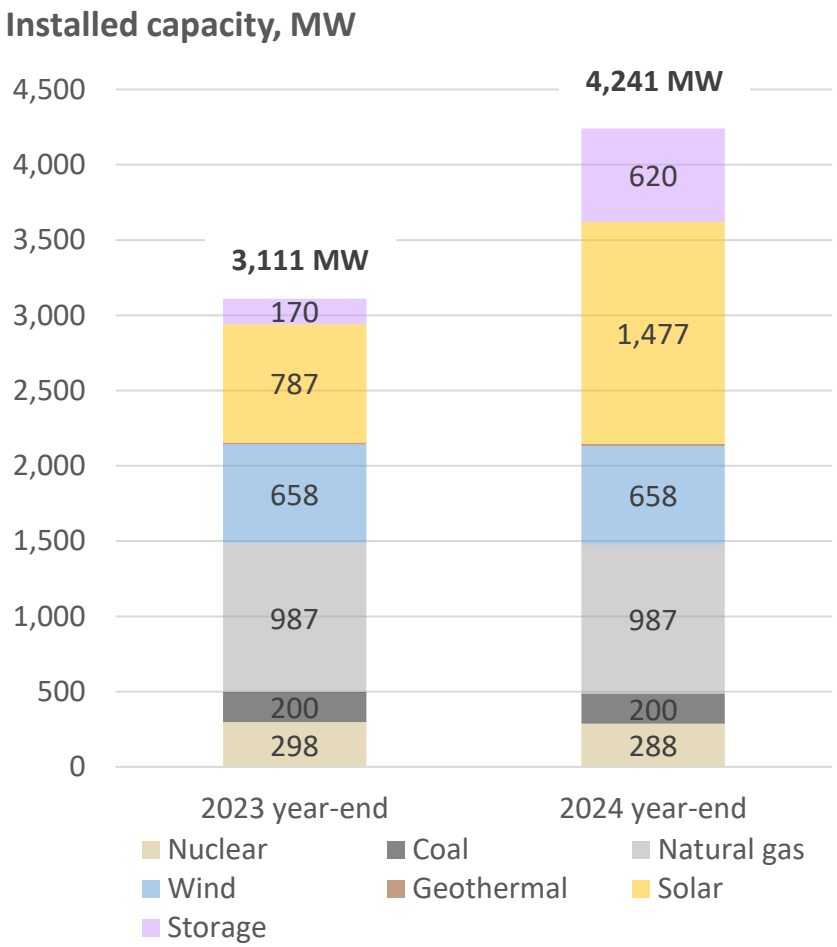


DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

PNM'S EXISTING RESOURCE PORTFOLIO AND NEAR-TERM RESOURCE ADEQUACY



2024 capacity

Storage: 620

Solar: 1,477

Wind: 658

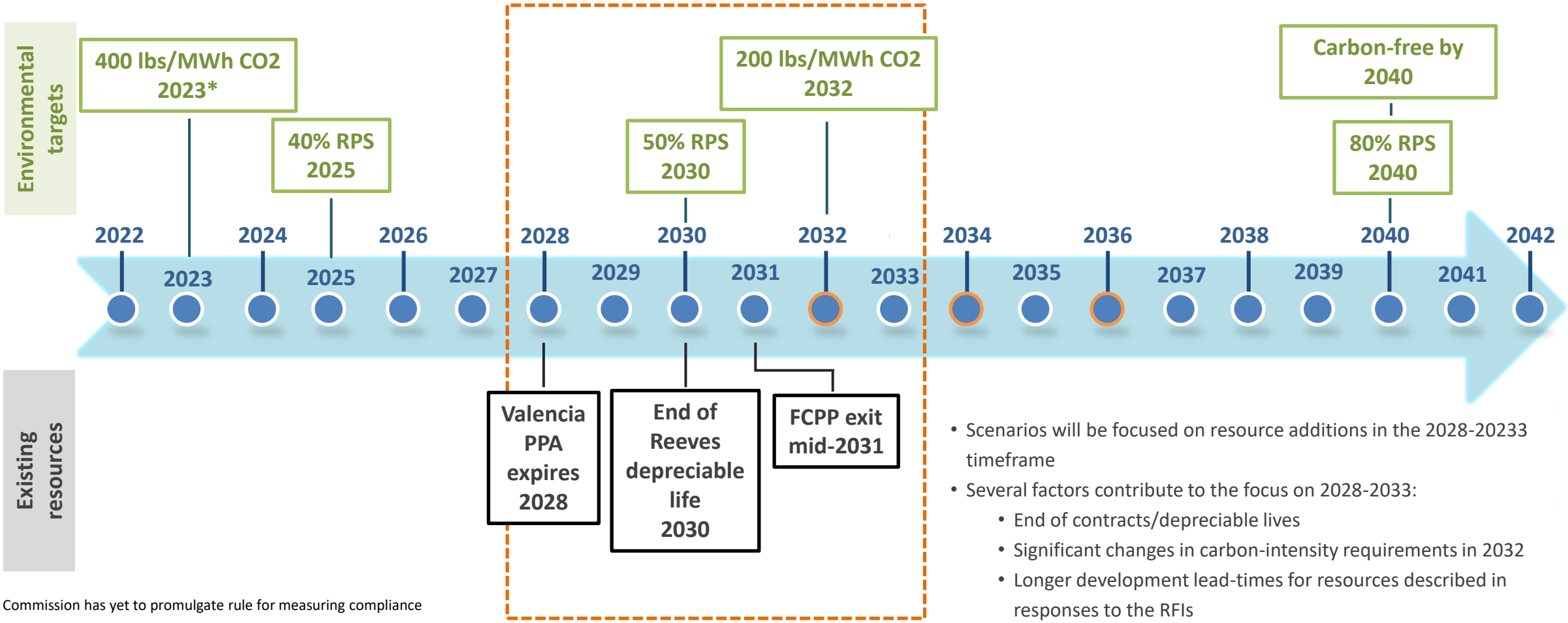
Natural Gas: 987

Coal: 200 MW

Nuclear: 288 MW share of Palo Verde

- Near term additions include 400 MW of solar and 170 MW of storage by the end of 2023
- By year-end 2024, PNM will have added an additional 690 MW of solar and 450 MW of storage
- RFPs for 2026-2028 are currently ongoing

KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS POINT TO 2028-2033 AS A CRITICAL PERIOD



- Scenarios will be focused on resource additions in the 2028-20233 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs

* Commission has yet to promulgate rule for measuring compliance

TECHNOLOGIES AVAILABLE IN PHASES 1-2

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



Energy efficiency and demand response included in all scenarios

DISCLAIMER - RESULTS ARE PRELIMINARY DRAFT

- PNM has incorporated numerous updates to its modeling in this IRP cycle
- While we have taken every effort to ensure the validity of these techniques, please understand that the results we will discuss are considered preliminary draft results and will likely change as we continue to refine the analysis
- In previous IRP cycles we would not present results before a full draft of the IRP was ready; we have made efforts to get stakeholders involved earlier in this IRP cycle, starting the public advisory process earlier than ever
- In order to maximize stakeholder involvement, presenting preliminary results and inviting feedback earlier is equally important
- At this stage, we will highlight some of the key trends we see so far, and some of the areas that require further study and refinement

PHASE 1 SCENARIOS EXPLORE ATTRIBUTES OF A VARIETY OF TECHNOLOGIES

Scenario Name	Scenario-Specific Assumptions
Base technologies	Only solar, storage, and EE, DR allowed through 2032
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 energy 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 hydrogen-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 hydrogen-fueled CT & ~750 MW electrolyzer added in 2031

- In Phase 1, technology-specific scenarios are screened under the following conditions:
  1. **CT&P future (capacity expansion run)**
     a) P50 load 8760 production cost run
     b) Extreme weather load 8760 production cost run
- **This approach gives PNM the ability to evaluate scenarios based on:**
  - Overall cost
  - Ability to accommodate extreme weather load
- All portfolios include option to add base technologies (including DR and EE) at any time
- ***All portfolios required to meet reliability, RPS, and carbon-intensity targets***

Preliminary

PNM Talk to us. PNM.com

PHASE 2 SCENARIOS EXPLORE SYNERGIES BETWEEN TECHNOLOGIES

Preliminary

Scenario Name	Scenario-Specific Assumptions
PHS 70-hr + CT	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready CTs allowed
PHS 70-hr + CT + wind	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
PHS 70-hr + Linear gen.	300 MW of pumped storage (70-hr) by 2032; new hydrogen-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 hydrogen-ready CTs allowed
PHS 8-hr + CT + wind	300 MW of pumped storage (8-hr) by 2032; new hydrogen-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 energy storage by 2032; new hydrogen-ready CTs allowed
IAS + CT + wind	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
IAS + Linear gen.	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready linear generators allowed
IAS + Afton CCS	At least 100 MW of iron air energy 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 energy storage and at least 100 MW liquid air energy storage by 2032
Green hydrogen + wind	~250 MW hydrogen-fueled CT & ~750 MW electrolyzer added in 2031; new wind beginning in 2028
Flow + CT	At least 100 MW of flow batteries (10-hr) by 2032; new hydrogen-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 + CT + LDES	Model has option to add base technologies, CTs (2026+), and any long-duration storage technology (2028-2033)
Base tech + LDES	Model has option to add base technologies and any long-duration storage technology (2028-2033)

- In Phase 2, PNM designed more complex portfolios consisting of two or more RFI technologies – the intent is to explore synergistic effects of combining operating characteristics
- All portfolios include option to add base technologies (including DR and EE) at any time
- Scenarios are screened under the same conditions as in Phase 1
- ***All portfolios required to meet reliability, RPS, and carbon-intensity targets***

PNM Talk to us. PNM.com

PNM MODELING RESULTS UPDATE – PRELIMINARY

PROPOSED PORTFOLIO EVALUATION CRITERIA: PHASES 1-2

RELIABILITY (INITIAL HURDLE)

- Check to ensure unserved energy is within a reasonable range
- Compare EnCompass portfolio EUE from extreme weather simulations to EUE from a SERVM tested reliable portfolio
- If EnCompass portfolio EUE falls within range of EUE from SERVM reliable portfolio, then portfolio/technology passes reliability test

COST (SCORE COMPONENT)

- Measured as present Value of Revenue Requirement, which reflects total cost of portfolio across study period
- Comparison of overall costs

TECHNOLOGY RISK (SCORE COMPONENT)

- Measured as a weighted average Technology Readiness Level
- Each portfolio assigned a weighted average TRL based on the 2032 firm capacity breakdown
- Comparison of dependence on less proven technologies on a firm capacity basis

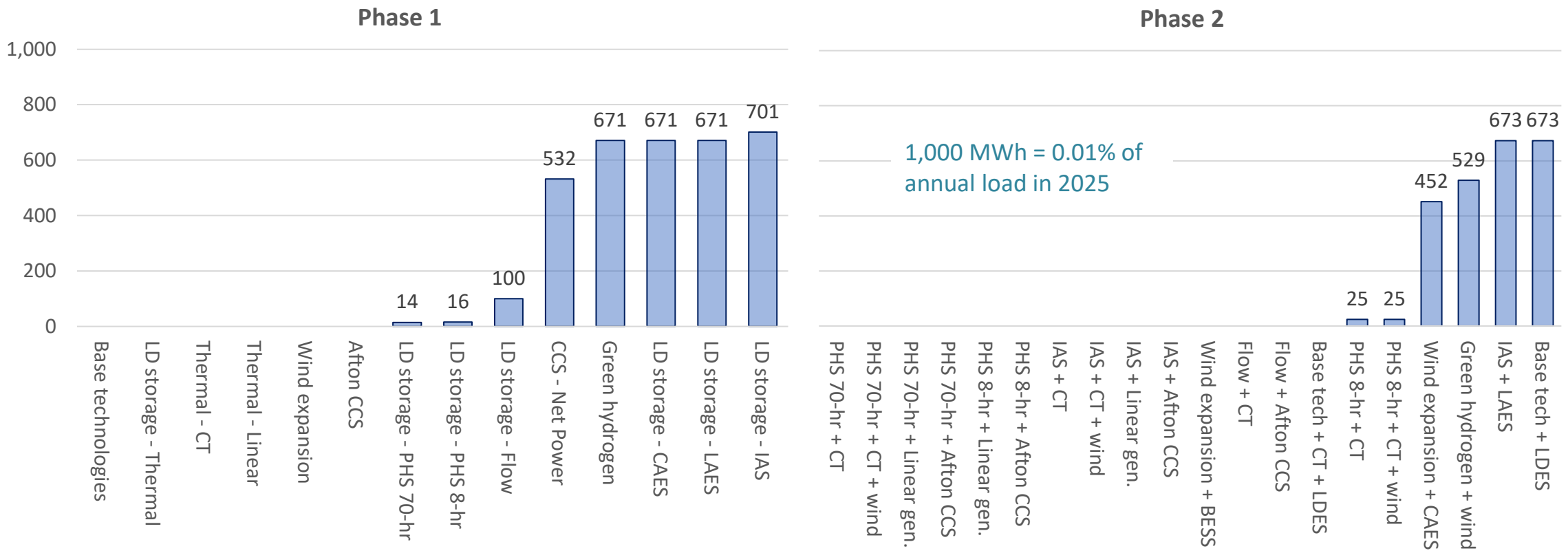
CARBON EMISSIONS (SCORE COMPONENT)

- Measured as NPV of total carbon emissions across study period (10% discount factor)
- Comparison of carbon emissions associated with scenario-specific combination of technologies
- Earlier abatement improves CO2 metric

Preliminary results

PORTFOLIOS RANKED BY UNSERVED ENERGY UNDER EXTREME WEATHER LOAD CASE

2040 unserved energy under extreme weather load case, MWh

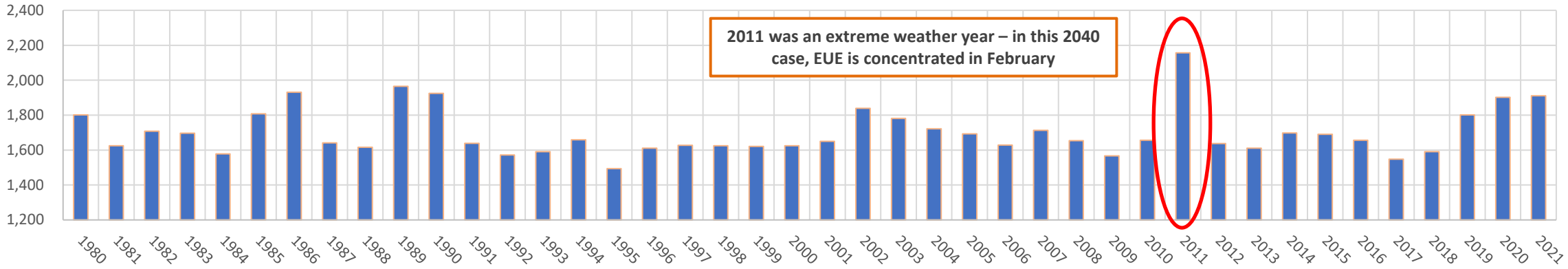


Talk to us.

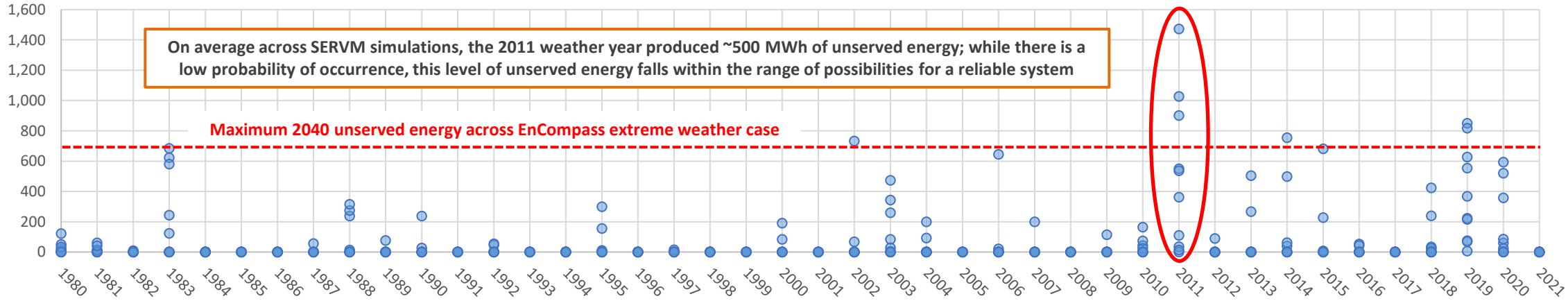
Preliminary results

PUTTING UNSERVED ENERGY IN CONTEXT: 2040 RESULTS FROM 0.1 LOLE CASE (BASE TECHNOLOGIES ONLY)

2040 peak February load by weather year, MW



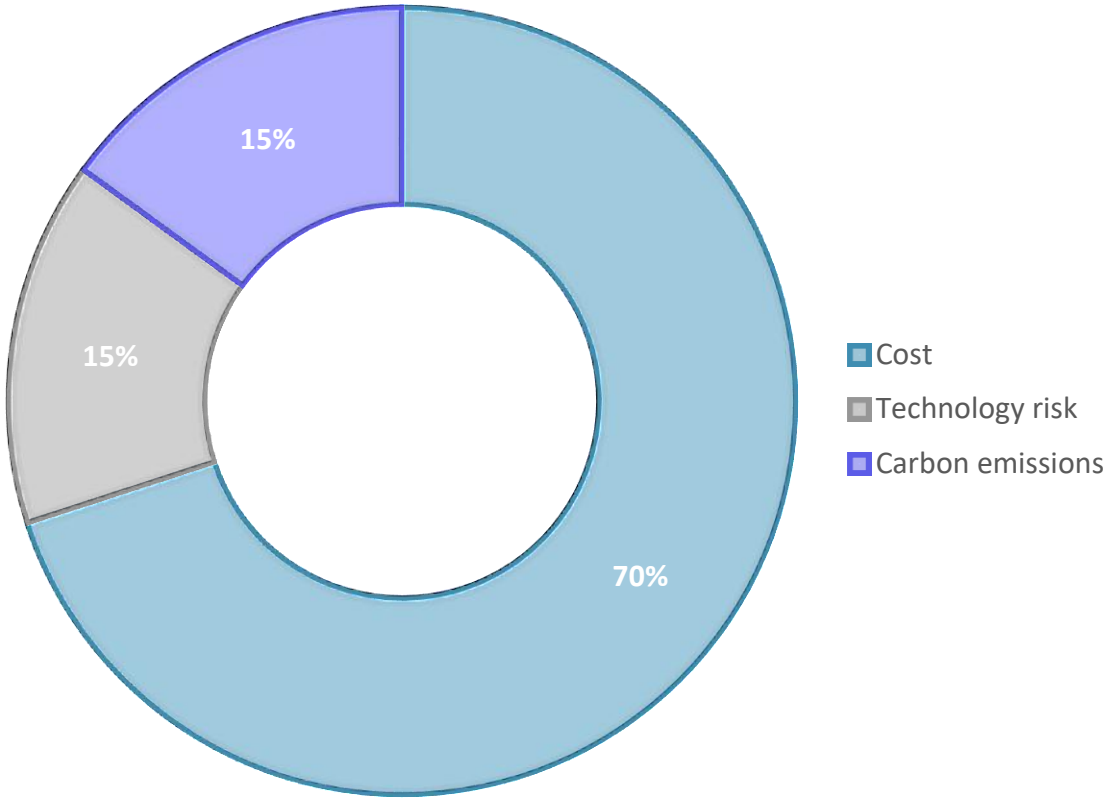
2040 EUE across 10 simulations by weather year, MWh



Talk to us.

SCORING MATRIX APPROACH AND POTENTIAL CRITERIA WEIGHTING (PHASE 1 & 2)

Preliminary PNM evaluation criteria weighting for overall portfolio score



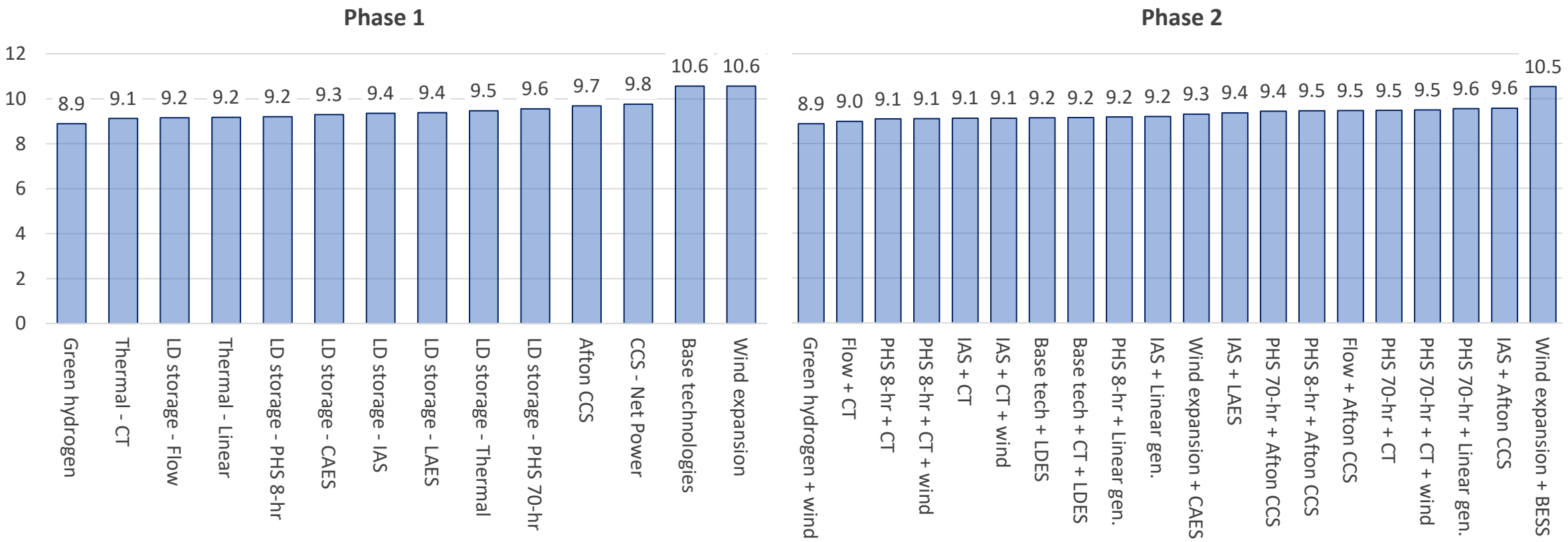
All portfolios meet carbon intensity and RPS requirements

- Each portfolio is given a score for each metric
- Scores range from 1 to 10, with 1 being the highest possible score
- For example, the portfolio with the lowest PVRR across all portfolios receives a score of 1 for the PVRR metric, the portfolio with the highest PVRR receives a score of 10
- The scores are then weighted and summed for a final portfolio score; portfolios with lower scores are preferred

Preliminary results

PORTFOLIOS RANKED BY PRESENT VALUE OF REVENUE REQUIREMENT

Present value of Revenue Requirement, $B

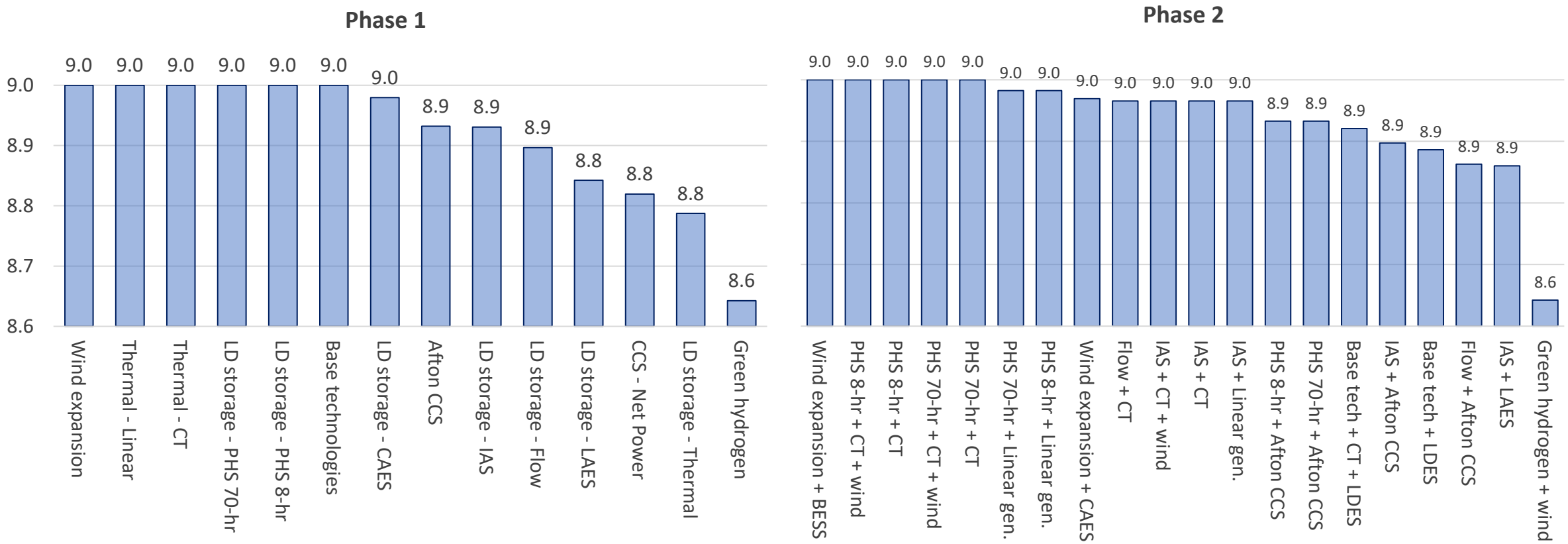


Talk to us.

Preliminary results

PORTFOLIOS RANKED BY WEIGHTED AVERAGE TECHNOLOGY READINESS LEVEL

Weighted average TRL (based on firm capacity in 2032)

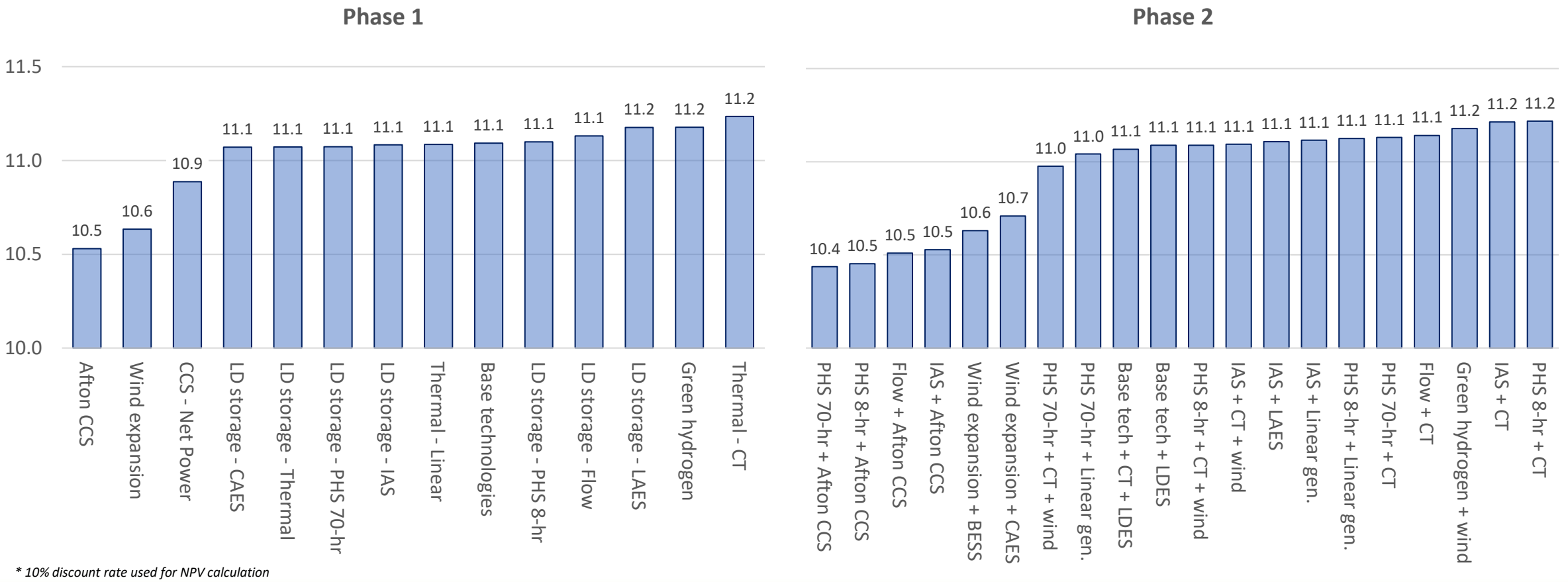


PNM Talk to us. PNM.com

Preliminary results

PORTFOLIOS RANKED BY TOTAL CARBON EMISSIONS 2023-2042

NPV of carbon emissions 2023-2042, MM tons*

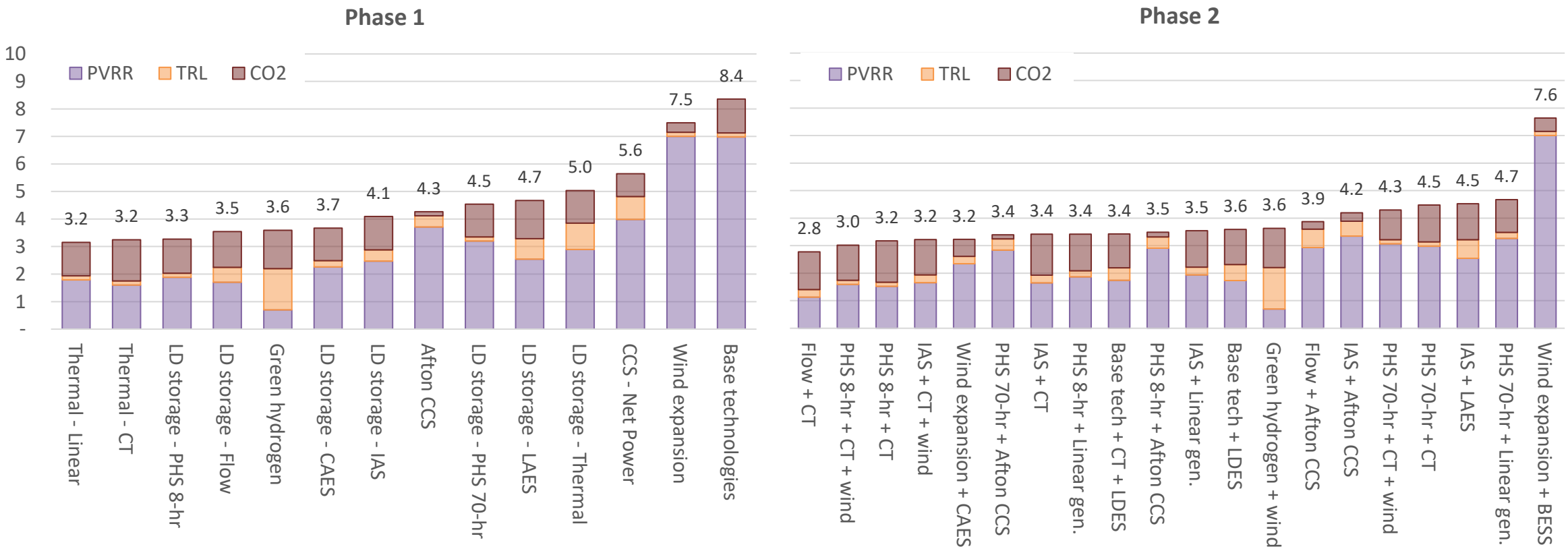


** 10% discount rate used for NPV calculation*

Preliminary results

SCORED PORTFOLIOS USING PRELIMINARY PNM CRITERIA AND WEIGHTING SCHEME

Total score breakdown by weighted component

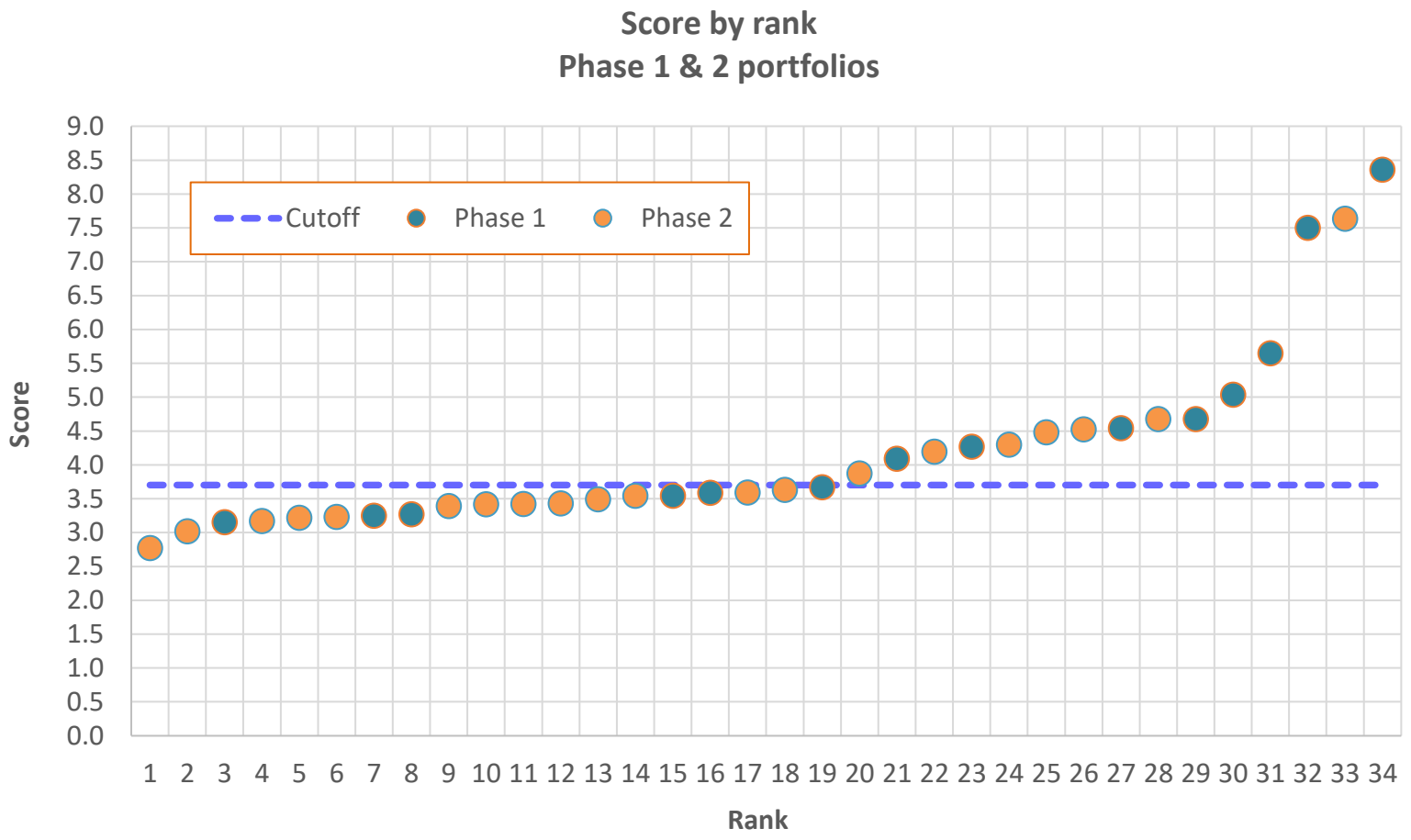


All portfolios required to meet reliability, RPS, and carbon-intensity targets

Preliminary results

PHASES 1-2 INFORM PHASE 3 TECHNOLOGY SELECTION

- Portfolio scores across Phases 1-2 indicate a “cutoff point”
- All unique technologies included in portfolios below the cutoff point will be included in Phase 3 modeling
- Phase 3 modeling will focus on “kitchen sink” scenarios in which EnCompass can select from a wide array of technologies selected from Phases 1-2
- Results from Phases 1-2 will help to contextualize results from Phase 3, and provide good comparison points

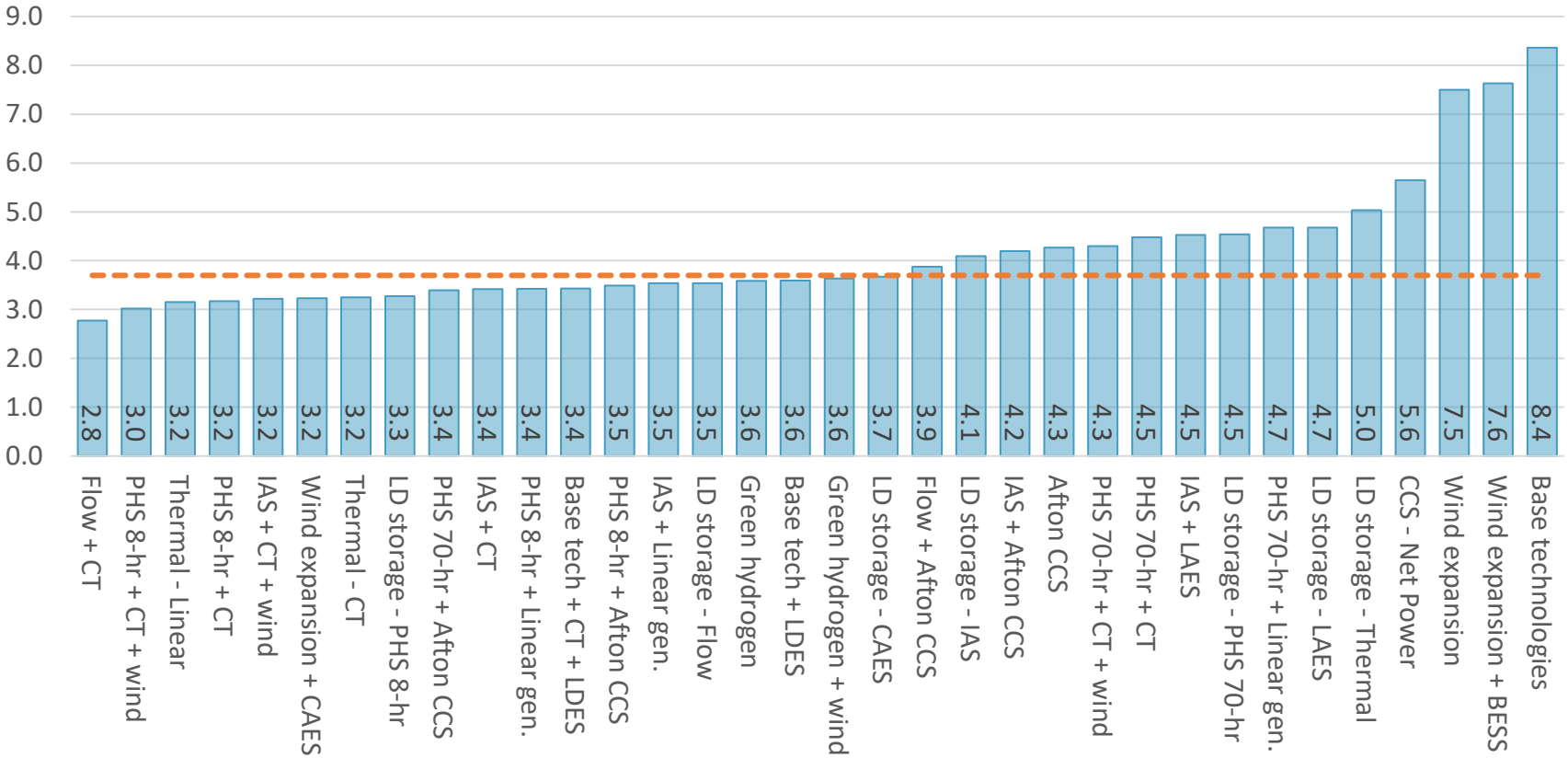


Talk to us.

Preliminary results

PHASE 3 TECHNOLOGY SELECTION

Total score for all scenarios



Unique technologies selected for Phase 3 modeling:

- CAES
- Flow battery
- PHS (8-hr & 70-hr)
- IAS
- CT
- Linear generator
- Wind expansion
- Afton CCS (Afton retrofit)
- Green hydrogen

Preliminary

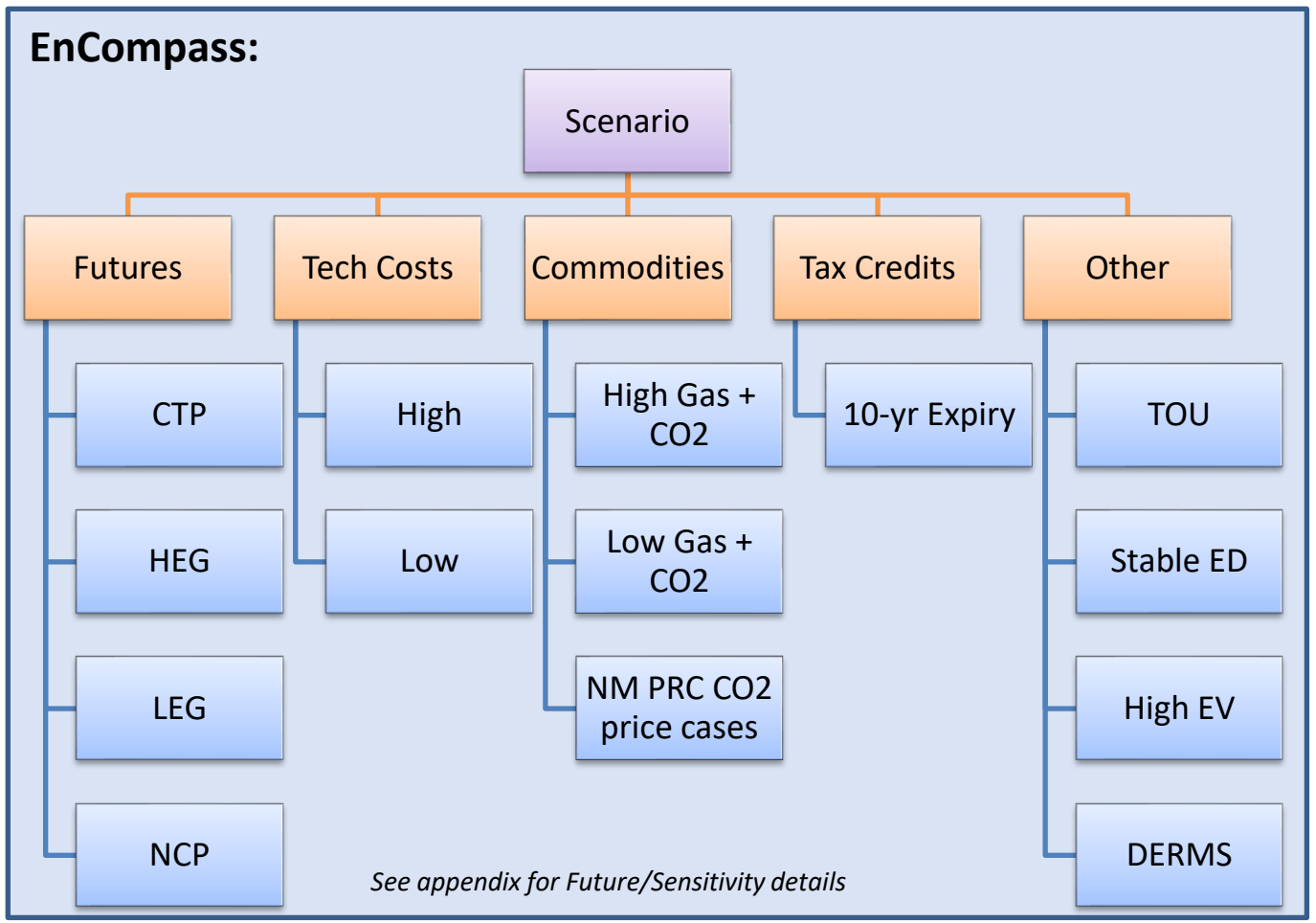
FIVE SCENARIOS FOR PHASE 3 MODELING

Base technologies only	Base technologies + CTs	Base technologies + all LDES *(stakeholder scenario)*	Base technologies + CTs + all LDES	Phase 1-2 technologies
Resource options	**Resource options**	**Resource options**	**Resource options**	**Resource options**
• Solar • Wind • 4-hr storage • EE/DR	• Solar • Wind • 4-hr storage • EE/DR • CT	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 70-hr • PHS 8-hr • IAS • LAES • Thermal storage	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 70-hr • PHS 8-hr • IAS • LAES • Thermal storage • CT	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 8-hr • PHS 70-hr • IAS • CT • Linear generator • Wind exp. • Afton CCS • Green hydrogen

PNM Talk to us. PNM.com

PHASE 3 MODELING

EnCompass:



SERVM:

CT&P case run for each scenario to determine:

- LOLE meets ~0.1 target
- EUE for portfolio

Preliminary

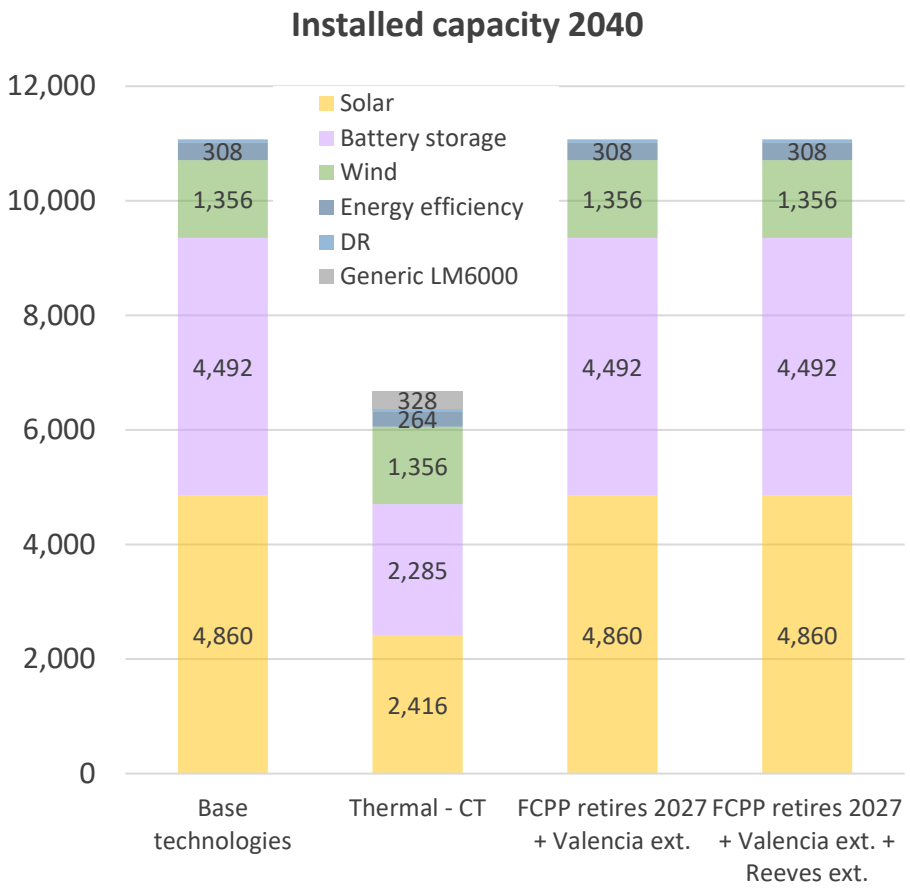
NEXT STEPS: PHASE 3 EVALUATION WILL ANALYZE PORTFOLIO PERFORMANCE ACROSS A VARIETY OF SENSITIVITIES

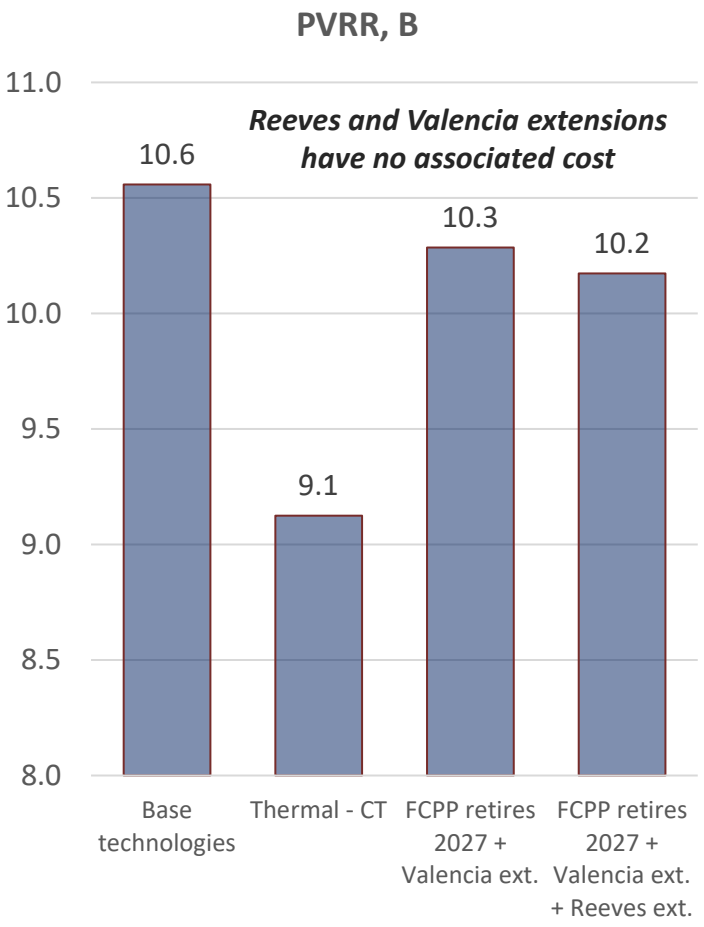
- Use all information gathered in Phase 3 to determine MCEPs:
  - Compare metrics across portfolios – NPV of Cost, CO2, TRL
  - Evaluate which technologies are consistently included across sensitivities (applies to “kitchen sink” cases)
  - Analyze reliability results from SERVM runs (CT&P)
    - Scenario meets ~0.1 LOLE target
    - Compare EUE across scenarios

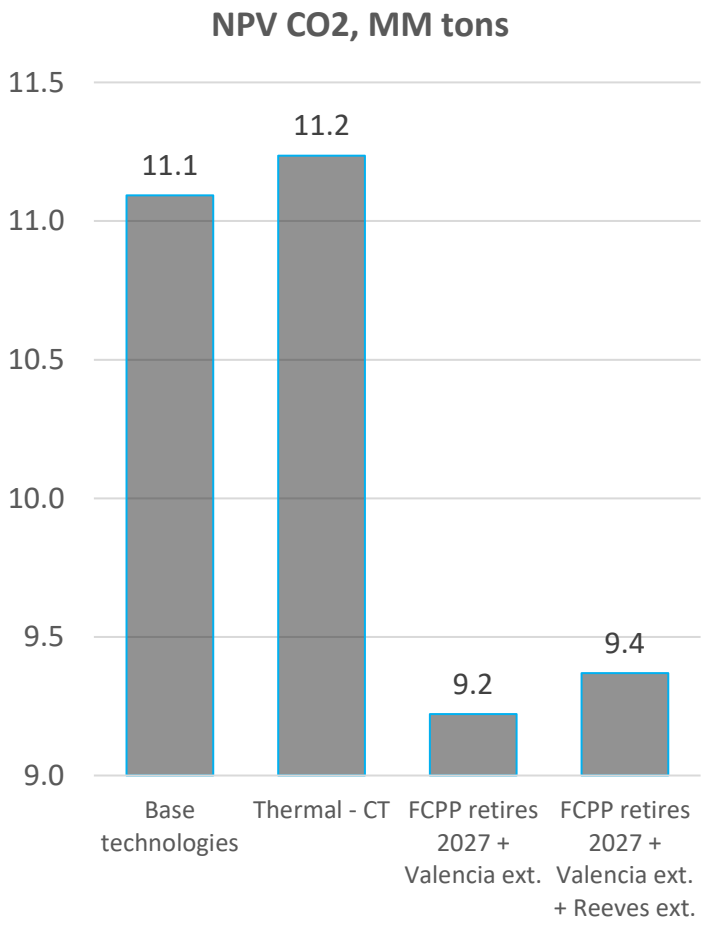
STAKEHOLDER MODELING RUN REQUESTS: MODELING RESULTS

Preliminary results

STAKEHOLDER-REQUESTED SCENARIOS: FOUR CORNERS ABANDONMENT SENSITIVITIES

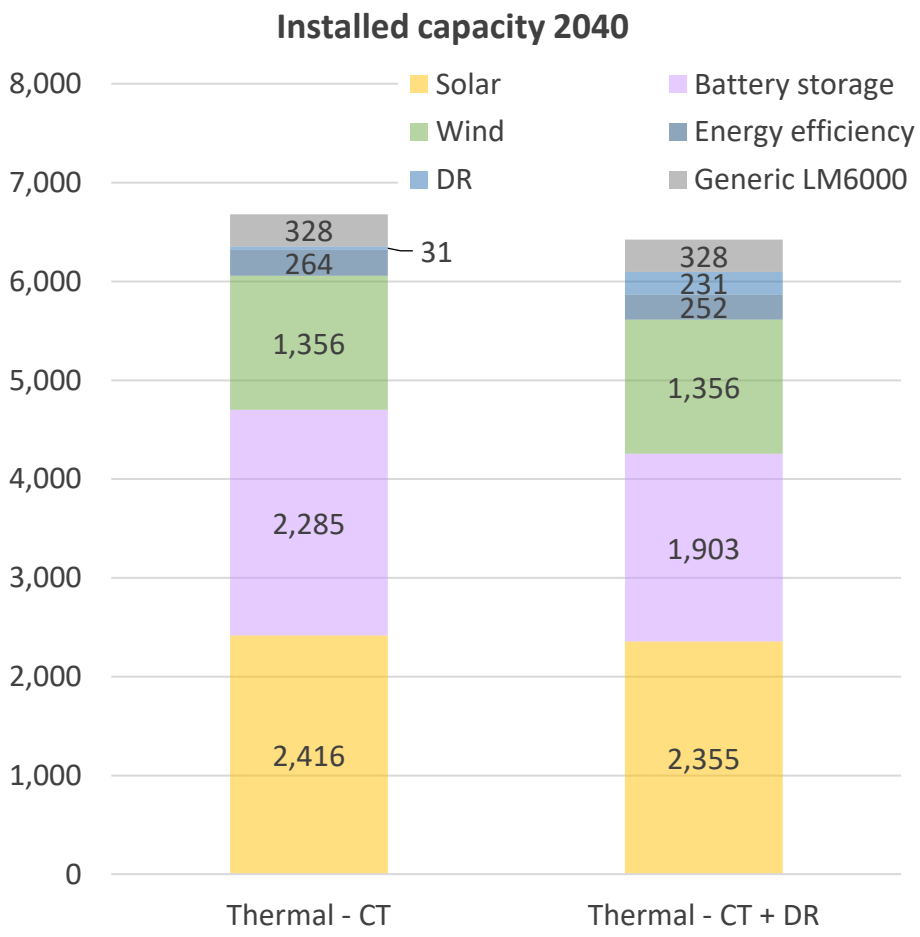


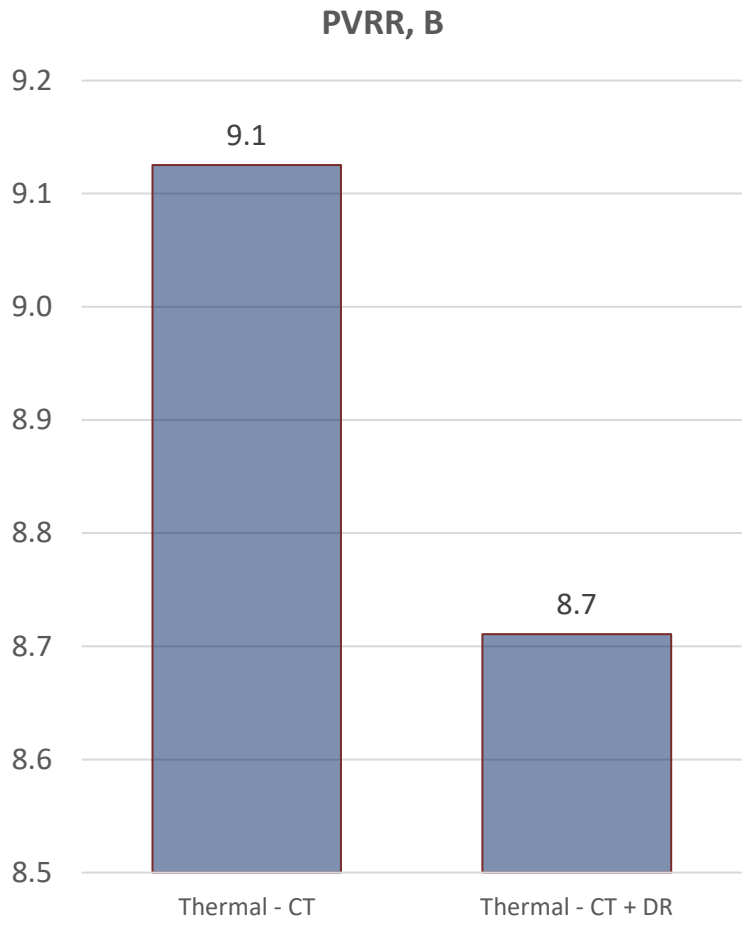


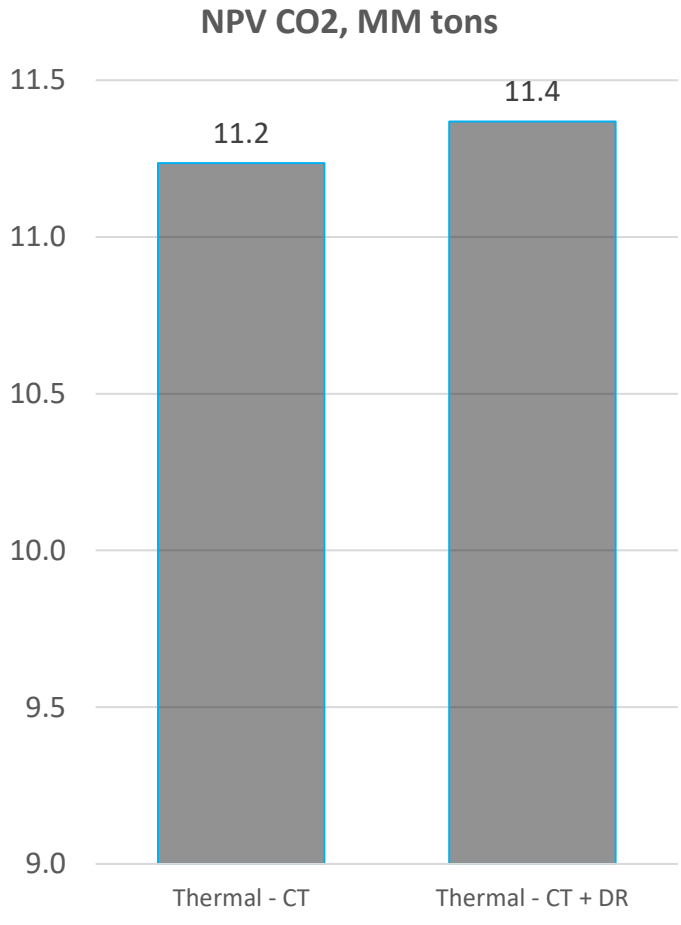


Preliminary results

STAKEHOLDER-REQUESTED SCENARIOS: INCREASED DEMAND RESPONSE







Talk to us.

Preliminary results

PNM'S INITIAL OBSERVATIONS & NEXT STEPS

Observations

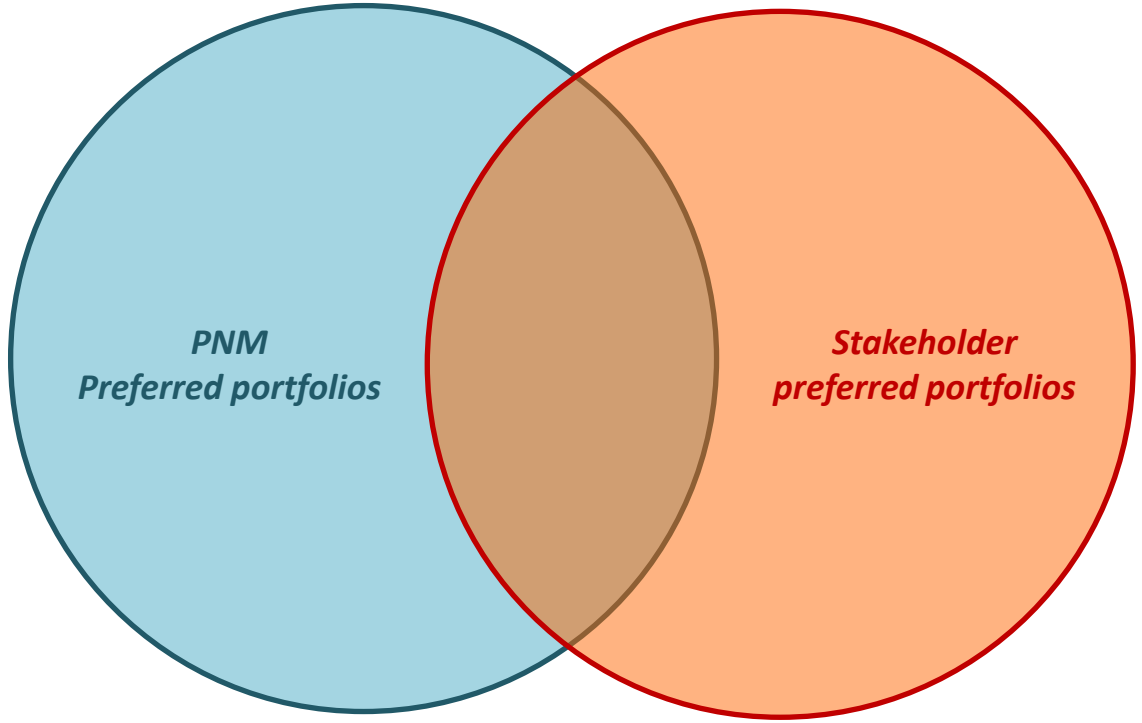
- Lowest-cost portfolios include dispatchable technologies and long-duration storage
- Technology combinations provide lower-cost alternatives to single-technology scenarios
- Base technologies results in a very high level of builds – which translates to high cost
- Portfolios with wind and/or carbon capture technologies have the lowest carbon emissions
- Wind helps to decarbonize the system and is included in all portfolios; however, earlier transmission expansion alone doesn't drive significant cost savings
- Portfolios with TRLs below 9 represent some technology risk; we recognize the importance of due diligence around technology risks given our carbon-free target
- Unserved energy under extreme weather cases is lowest for portfolios with dispatchable resources

Next Steps

- Continue to refine modeling approaches
- Examine robustness of initial observations against key futures and sensitivities (Phase 3)
- Explore implications of technology cost uncertainty upon results that rely heavily on emerging technologies (Phase 3)
- Conduct reliability modeling of most promising portfolio options (SERVM in Phase 3)
- Compare quantitative and qualitative metrics for Phase 3 portfolios to inform best path forward for Most Cost-Effective Portfolio

PORTFOLIO SCORING SYSTEM

- PNM proposes that stakeholders evaluate modeled portfolios using the same methodology as PNM, but with their own criteria and weighting scheme for portfolio scoring
- PNM suggests that stakeholders determine their evaluation criteria, and for each criterion, a metric for measurement and an associated weight
- These can then be to determine an overall portfolio score for each portfolio modeled
- Once stakeholders have a list of preferred portfolios based on their criteria and weighting scheme, preferred portfolios can be compared



APPENDIX

2023 IRP CORE FUTURES

Key assumption	Current Trends & Policy	High Economic Growth	Low Economic Growth	National Carbon Policy (Carbon-free by 2035)
Load forecast	Mid	High	Low	High
BTM PV forecast	Mid	High	Low	High
EV adoption forecast	Mid	High	Low	High
Building Electrification Forecast	Mid	Mid	Mid	High
Economic development	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

2023 IRP SENSITIVITIES

Gridworks Compiled Presentations

	Sensitivity	Load forecast	Economic Development	BTM PV forecast	EV adoption forecast	Building electrification	Gas price forecast	CO2 price forecast	Technology costs	IRA tax credits & incentives
Load	High load	**High**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Strong ED growth	Mid	**Stable**	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Very strong ED growth	Mid	**Stable**	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Extreme weather	**P90 hot/cold**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Low load	**Low**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	TOU pricing	**TOU shaping**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
BTM	High BTM PV	Mid	Limited ED	**High**	Mid	Mid	Mid	Mid	Mid	Extended
	Low BTM PV	Mid	Limited ED	**Low**	Mid	Mid	Mid	Mid	Mid	Extended
	No BTM PV	Mid	Limited ED	**Zero**	Mid	Mid	Mid	Mid	Mid	Extended
	High EV adoption	Mid	Limited ED	Mid	**High**	Mid	Mid	Mid	Mid	Extended
	Low EV adoption	Mid	Limited ED	Mid	**Low**	Mid	Mid	Mid	Mid	Extended
	High building electrification	Mid	Limited ED	Mid	Mid	**High**	Mid	Mid	Mid	Extended
	DERMS	Mid	Limited ED	**High**	**High**	Mid	Mid	Mid	Mid	Extended
Gas price	High gas price	Mid	Limited ED	Mid	Mid	Mid	**High**	Mid	Mid	Extended
	Low gas price	Mid	Limited ED	Mid	Mid	Mid	**Low**	Mid	Mid	Extended
Carbon price	IRP rule $40 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$40/ton**	Mid	Extended
	IRP rule $20 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$20/ton**	Mid	Extended
	IRP rule $8 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$8/ton**	Mid	Extended
	PNM high CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**High**	Mid	Extended
	PNM mid CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	PNM low CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**Low**	Mid	Extended
Technology costs	Fast technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	**Low**	Extended
	Slow technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	**High**	Extended
	IRA tax credits expire	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	**Expire 2032-2034**

TECHNOLOGY READINESS LEVEL DEFINITIONS

TRL 0 – Idea phase
- Unproven Concept with no testing having been done

TRL 1 – Basic Research
- Needs of the technology can be described, but have no evidence

TRL 2 – Technology Formulation
- Concept and application have been formulated

TRL 3 – Needs Validation
- You have an initial "offering", stakeholders are interested

TRL 4 – Small Scale Prototype
- Built in laboratory environment.

TRL 5 – Large Scale Prototype
- Tested in intended environment

TRL 6 – Prototype System
- Tested in intended environment with close to expected performance

TRL 7 – Demonstration System
- Operating in operational environment at pre-commercial scale

TRL 8 – First of Kind Commercial System
- All technical processes and systems to support commercial activity at ready state

TRL 9 – Full Commercial Application
- Technology on "general availability" for all consumers

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



Meeting #7: July 27, 2023

IRP Modeling Q&A

Contents

Meeting #7: July 27, 2023 1
Michael Barrio, Advanced Energy United: Reliability evaluation 2
Athena Christodoulou, CSOL Power: Carbon emissions 2
Cynthia Mitchell, NM PRC: Fuel supply and price volatility sensitivities 3
Alondra Regalado, Strategen: Technology Readiness Level scale 4
Cynthia Mitchell, NM PRC: IRA incentives 5
Brian Johnson, NM RETA: Base Technologies only scenario cost 5
Cynthia Mitchell, NM PRC: Thermal-CT scenario 5
Cynthia Mitchell, NM PRC: Hydrogen costs in Thermal-CT scenario 6
Maria Scheller, ICF International: Hydrogen economics 6
Gwen Farnsworth, Western Resource Advocates: Hydrogen costs 7
Cynthia Mitchell, NM PRC: Scenarios in Phase 2 vs. Phase 3 7
Cynthia Mitchell, NM PRC: Valencia/Reeves extension scenarios 8
Cynthia Mitchell, NM PRC: Hydrogen costs in Thermal-CT case 8
Thomas Solomon, Member of the Public: PVRR translation to bill impacts 9
Ed Rilkoff, NM PRC: Thermal-CT scenario vs. Valencia/Reeves extension scenarios 10
Ed Rilkoff, NM PRC: Carbon emissions scoring criteria 11
Gwen Farnsworth, Western Resource Advocates: Survey factors use in IRP 11
Glen Wilke, NM State University: RFP resources in IRP modeling 11
Cynthia Mitchell, NM PRC: Hydrogen costs 12
Gwen Farnsworth, Western Resource Advocates: CT conversion for hydrogen combustion capability 12

414 Silver Ave. SW; Albuquerque, NM 87102

Michael Barrio, Advanced Energy United: Reliability evaluation

What was the reasoning for scuttling reliability?

PNM response:

All portfolios are designed to meet a baseline Planning Reserve Margin (PRM) (calibrated to a 0.1 LOLE target); however, as we have discussed previously, PRM alone is insufficient to guarantee a reliable system. As a part of Phase 1-2 modeling, we performed a reliability check on all portfolios – see slides 10-12 of PNM modeling results update presentation. When these portfolios were evaluated under a deterministic extreme weather load case, we did not find that any portfolio had unserved energy outside the range of outcomes considered reasonable for a reliable portfolio. Further, there was not enough differentiation in this deterministic approach to justify the weighting we originally contemplated.

As a part of Phase 3, we will conduct detailed reliability modeling via SERVM. Additionally, we plan to conduct resiliency studies with the Most Cost Effective Portfolios (MCEPs) and we will give these results significant weighting when evaluating Phase 3 portfolio scores.

Athena Christodoulou, CSOL Power: Carbon emissions

Are carbon emissions only restricted to operations and not upstream?

PNM response:

Carbon emissions reflect those that result from the combustion of fossil fuels for electricity generation to serve PNM retail load.

Our modeling is consistent with the emissions requirements laid out in the New Mexico Energy Transition Act. This prescribes carbon intensity levels for emissions that result from electric power generation, i.e., stack emissions.

414 Silver Ave. SW; Albuquerque, NM 87102

Cynthia Mitchell, NM PRC: Fuel supply and price volatility sensitivities

IRP App A specifies fuel supply and price volatility as one of the criteria for evaluation. If PNM is to continue with the "donut" this should be added.

PNM response:

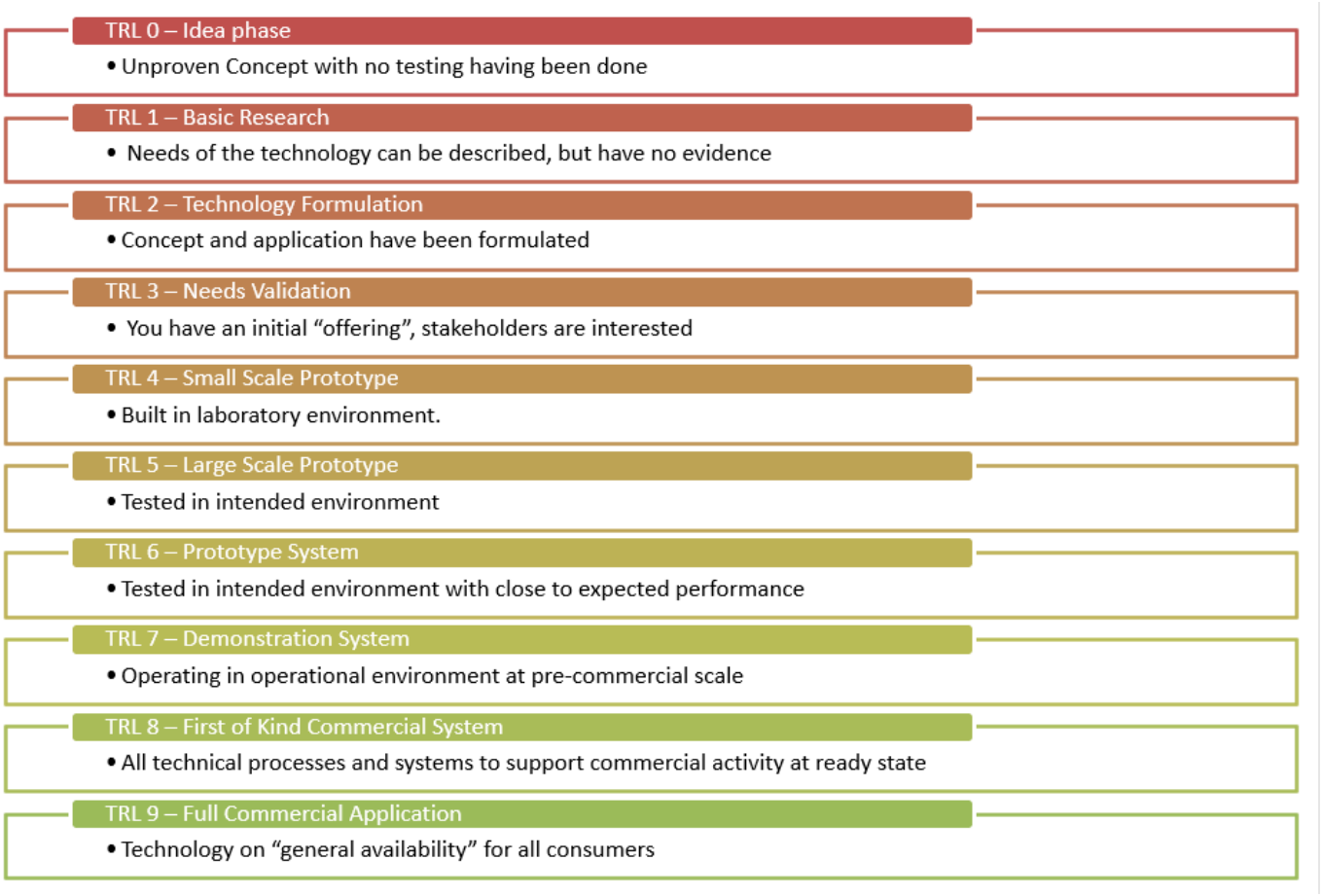
PNM will model a variety of sensitivities in Phase 3 scenarios, including those that incorporate high and low natural gas and market prices. Sensitivities can be found on slides 21 and 30 of PNM's modeling results update presentation.

414 Silver Ave. SW; Albuquerque, NM 87102

Alondra Regalado, Strategen: Technology Readiness Level scale

Do you have a TRL scale that you can share with us?

PNM response:



414 Silver Ave. SW; Albuquerque, NM 87102

Cynthia Mitchell, NM PRC: IRA incentives

I understood that the IRA provides incentives, funding, etc. for variety of technologies, hydrogen, RE, storage, DERs. Have you been able to include IRA effects on all resource types?

PNM response:

PNM has incorporated Investment Tax Credits for all storage and Carbon Capture technologies, and Production Tax Credits for renewable, nuclear, and hydrogen production.

Brian Johnson, NM RETA: Base Technologies only scenario cost

Why are base tech costs high? Compared to tech that is not considered ready?

PNM response:

The Present Value of Revenue Requirement for each portfolio (presented on slide 14) reflects the portfolio cost over the study period. The cost for the "base technologies only" portfolio is highest because it requires the greatest amount of installed capacity (due to ELCC effects and the lack of long-duration storage or new dispatchable resources in that scenario).

Cynthia Mitchell, NM PRC: Thermal-CT scenario

Clarify the "thermal -CT" scenario. I believe that is hydrogen-ready CT, right?

PNM response:

The "Thermal – CT" scenario includes base technologies, and allows for the addition of Combustion Turbines capable of burning hydrogen in 2040 and beyond (these incur a hydrogen conversion cost in 2040). The hydrogen burned in these CTs in 2040 and beyond is assumed to be delivered to the PNM system (as opposed to being created vis electrolysis using designated renewables and stored on site, as in the Green Hydrogen scenario).

414 Silver Ave. SW; Albuquerque, NM 87102

Cynthia Mitchell, NM PRC: Hydrogen costs in Thermal-CT scenario

What hydrogen-related costs are included in the CT scenario, conversion cost, CCS, fuel cost, hydrogen transport cost.

PNM response:

In the Thermal-CT scenario, all CTs remaining online in 2040 and beyond incur a conversion cost that reflects the necessary upgrades to enable 100% hydrogen combustion. The cost of delivered hydrogen ranges $20-21/MMBtu ($2025, base assumption) in 2040-2042.

In the Green Hydrogen scenario, costs associated with hydrogen production and combustion include hydrogen-ready CTs, electrolyzers (and associated PTCs for hydrogen production), solar resources to supply the electrolyzers (and associated PTCs), and hydrogen storage (above-ground).

Maria Scheller, ICF International: Hydrogen economics

Is the Hydrogen scenario economic in the long term after the IRA credits expire?

PNM response:

All of our modeling is based on our current understanding of the IRA and assumes the hydrogen PTC expires in 2032. Based on these assumptions, we don't see much hydrogen production and combustion once the hydrogen PTC expires. While the Green Hydrogen case is the lowest cost over the study horizon (2023-2042), cost advantages are directly attributable to PTC value (including PTCs for wind and solar).

However, the extent of the IRA impact on the Green hydrogen industry remains to be seen. The PTC is incredibly valuable and is likely to spur investments in green hydrogen production that provide for technology improvements and efficiency gains and could eventually result in a hydrogen economy. These types of developments may decrease the cost of initial investments in green hydrogen on a broader scale and help future project economics, particularly in places where there is a strong renewable resource. Extension of the hydrogen PTC can be expected to incentivize hydrogen investments further into the future.

Gwen Farnsworth, Western Resource Advocates: Hydrogen costs

To Cynthia's point on the hydrogen question, we'd like the filed IRP testimony to explain the hydrogen cost, and the assumptions for how hydrogen will be proven to be green that is underlying the cost estimate (including examples of real projects for hydrogen production).

PNM response:

The IRP is not filed with testimony, it is a report that is either accepted or sent back for revision based upon whether the IRP Statement of Need and Action Plan comply with the policies and procedures of the IRP rule (NMAC 17.7.3.9).

Cynthia Mitchell, NM PRC: Scenarios in Phase 2 vs. Phase 3

Slide 20: what is the difference/distinction between the Phase 2 last and next to last runs w/ all LDS and LDS+CT (slide 8), and what you show here # 3 and 4? PRC Staff would like to see a BaseTech with Valencia and Reeves extension and LDS.

PNM response:

a) Phase 3 will incorporate the Base technologies + LDES and Base technologies + LDES + CT scenarios also modeled in Phase 2 – there is no difference in the technologies available for the model to optimize in these scenarios between Phase 2 and Phase 3. However, when modeled under different sensitivities in Phase 3, these scenarios might produce different portfolios/resource mixes than in the Current Trends and Policy (CT&P) case modeled in Phase 2.
b) Per Gridworks, the deadline for submitting modeling run requests was May 26.

Cynthia Mitchell, NM PRC: Valencia/Reeves extension scenarios

Slide 24: should FC be adjusted now to reflect 2031? How does the early retirement FC effect the analysis? Q: There is no change in installed capacity between BT and V&R cases. You assumed 5-year extension on V&R? So, there might be value to a 5 year extension that is not being reflected here.

PNM response:

These scenarios were specifically requested by a stakeholder. The first assumes PNM exits its share of Four Corners in 2027, and the Valencia PPA is extended through 2039. The second assumes PNM exits its share of Four Corners in 2027, the Valencia PPA is extended through 2039, and Reeves continues to operate through 2039. In both of these requested scenarios, Valencia and Reeves extensions do not incur any costs – they are free (as agreed to by stakeholders in the modeling request meetings).

In the Base Technologies only scenario, Valencia PPA expires in 2028 and Reeves retires in 2031.

In 2040, the stakeholder requested scenarios produce the same portfolio as in the Base Technologies only scenario because Valencia and Reeves do not operate past 2039.

Cynthia Mitchell, NM PRC: Hydrogen costs in Thermal-CT case

PRC would like the underlying cost assumptions and 20-year cost stream (capital, fixed and variable O&M, and fuel costs), and any hydrogen related costs, for the CT case. Q: does PNM have similar cost data for Valencia and Reeves?

PNM response:

All available information can be found in the data sets posted to the Venue site. Because this is not an RFP evaluation, we will not be posting project-specific information, such as for a Valencia extension.

414 Silver Ave. SW; Albuquerque, NM 87102

Thomas Solomon, Member of the Public: PVRR translation to bill impacts

Can we translate the highest cost to the lowest cost portfolios into the real world? What would be the difference in an average consumer's monthly electric bill?

PNM response:

The IRP rule requires evaluation of portfolio costs over a planning horizon of at least 20 years, – we have done this with the PVRR metric. Bill impacts would only look at a single year and may not adequately capture long-term tradeoffs in resource choices. Furthermore, transforming PVRR into bill impacts would require assumptions around cost of service, cost allocation, ownership structures, etc. – this is beyond the scope of the IRP.

414 Silver Ave. SW; Albuquerque, NM 87102

Ed Rilkoff, NM PRC: Thermal-CT scenario vs. Valencia/Reeves extension scenarios

I am having difficulty understanding the thermal-CT case versus extending Valencia and Reeves. They're all just CT's burning gas except the thermal-CTs have the potential for hydrogen conversion at the end. Is this correct?

PNM response:

In the Valencia and Valencia & Reeves extension scenarios (stakeholder requests) there are no additions of thermal resources (and no hydrogen combustion) – the only new resource types available to the model are wind, solar, and 4-hr lithium-ion storage (the same as in the Base Technologies only scenario). However, one can glean from the Thermal - CT analysis whether gas fired generation is cost effective when Reeves or Valencia would come out of the portfolio. If similar amount of new gas is added at those times, one can conclude that whether new gas, or an extension of those units, is cost effective and the specific choice would come down to RFP bids in an RFP evaluation.

These two stakeholder-requested scenarios differ from the Base Technologies scenario in only two ways:

1. PNM exits its share of Four Corners in 2027 (as opposed to in 2031)
2. Either Valencia (in the Valencia extension scenario), or Valencia and Reeves (in the Valencia and Reeves extension scenario) extend through 2039 at no additional cost (as opposed to the Valencia PPA ending in 2028 and Reeves retiring in 2031)

The stakeholder requested scenarios differ from the Thermal-CT scenario in three ways:

1. PNM exits its share of Four Corners in 2027 (as opposed to in 2031)
2. Either Valencia (in the Valencia extension scenario), or Valencia and Reeves (in the Valencia and Reeves extension scenario) extend through 2039 at no additional cost (as opposed to the Valencia PPA ending in 2028 and Reeves retiring in 2031)
3. Options for new resource additions include only wind, solar, and 4-hr lithium-ion storage (as opposed to wind, solar, 4-hr lithium-ion storage, and generic Combustion Turbines that will be converted to burn hydrogen in 2040)

Ed Rilkoff, NM PRC: Carbon emissions scoring criteria

Is it necessary to score scenarios on carbon emissions when the NPVs are all very close and they all meet the ETA?

PNM response:

We think it's important to consider the extent to which some portfolios can provide for earlier reduction in carbon emissions. Given that all portfolios meet ETA requirements, the NPV CO2 metric receives an overall weight of 15% in the scoring methodology – far below the 70% weight given to portfolio cost (as measured by PVRR).

Gwen Farnsworth, Western Resource Advocates: Survey factors use in IRP

How would the 12 factors then be used in the IRP?

PNM response:

Stakeholders were asked to submit their top five factors (IRP evaluation criteria priorities) and rank by importance. PNM has proposed using the results of the factor survey to create a stakeholder-derived scoring matrix. Ultimately, we'd like to compare Phase 1-2 results scored using PNM's scoring matrix with those scored using the stakeholder matrix. The overall goal would be to understand where PNM and stakeholders align in terms of evaluation criteria and level of importance.

Glen Wilke, NM State University: RFP resources in IRP modeling

Re: the new 2026 storage and solar contracts covered at the start of this meeting, was their pricing already factored into the pricing assumptions used as input for the IRP modeling?

PNM response:

Final modeling results will incorporate 2026 RFP resources and associated costs. The results presented on July 27th do not reflect incorporation of these resources into IRP modeling.

Ultimately, the RFP resources will be the same in all portfolios so addition of these resources is not expected to materially change the comparison across portfolios.

Cynthia Mitchell, NM PRC: Hydrogen costs

Additional question for follow-up modeling discussion: for green hydrogen, could we please have all cost assumptions (capital, fixed and variable O&M, fuel, water, transportation) and the 20-year cost stream?

PNM response:

All available information can be found in the data sets posted to the Venue site. Because this is not an RFP evaluation, we will not be posting project-specific information.

Gwen Farnsworth, Western Resource Advocates: CT conversion for hydrogen combustion capability

If new CTs are assumed to use up to 30% hydrogen, depending on fuel availability assumptions, would they be restricted to a 20-year lifetime and depreciation period in the modeling? (Because a 30% H2 capable CT cannot be converted to 100% HC capability)

PNM response:

New CTs in the Thermal-CT case are assumed to burn natural gas through 2039. In 2040 they incur a conversion cost and are assumed to burn 100% hydrogen thereafter. Generic LM6000s have a 40-year operating life and depreciation period. This is appropriate because it is reasonable to assume that these resources will be able to utilize a non-carbon-emitting fuel (hydrogen or other) and operate for the entire 40-year life.

Integrated Resource Plan:
Statement of Need Table of Contents
Working group suggestions for Public Service New Mexico - May 31, 2023

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction
    a. The PNM Integrated Resource Plan 2023 provides a comprehensive long range path for building out the strongest, most reliable electrical power delivery system we can envision for our customers over the next 20 years. The IRP report begins with the current status of PNM's system, and shows how available resources and technologies can bring improvements. Simultaneously we recognize that changes are occurring in nearly every sector of the environment in which we operate. These will require ongoing re-evaluation and modifications to the 2023 IRP plan that will be incorporated in future triennial PNM IRPs.

    Meeting our clean energy goals and preserving system reliability, while providing for the growing needs of our customers in an affordable manner, will require the addition of significant amounts of new generation capacity over the next twenty years. We anticipate that between today and 2040, the likely amount of new installed generation capacity will total between 4,000 to 5,000 MW or more. This amount of *new* capacity is significantly greater than the amount that exists today, implying that the achievement of our goals will require continuous and significant evolution of our portfolio. [For context, please include here: Current PNM capacity so we see what growing to 4-5K means and # of customers on the PNM system now and if changing in the future] Barbara

    This IRP does not represent a future system design or even a pathway to a full system design for the PNM planned 2040 zero carbon grid. The action plan, dictated in the IRP rules, only provides a 3-year detailed plan and thus any identified resources past 2027 are currently speculative. The limited timeframe of an action plan may well serve a semi-static resource portfolio with a highly predictive load profile, but the addition of a State clean energy policy requirements, which requires a massive rebuild of the entire 100-year-old system, may require a more defined and longer-term action plan to initiate actual projects toward building out the final solution. Given the buildout of long duration energy storage and other zero carbon dispatchable power generation could take decades and cost tens of billions of dollars, an IRP that can

only speculate on this future is insufficient for determining the most reliable and affordable system, that can be initiated today, to meet the operational needs of the grid a mere 16-years from now.

2. Vision and Goals
    a. The identification of a set of resources and a sequencing of those resource deployments that conforms to the regulations and policies of the State of New Mexico, reliably serves all customers at a reasonable cost with electrical energy that is that is resilient in the face of national security, technology, infrastructure, resource, cyber and environmental constraints.
    b. Goals
        i. Reliability and Resilience: Utility's Obligation to Serve
            1. Minimum Reserve Requirements
            2. Reliability Standards
            3. Swift recovery from climate or security threats
        ii. Public Interest and Equity
            1. Responsibilities to Ratepayers and Shareholders
                a. Affordability
                b. Availability to Underserved Communities
                c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
            2. Costs associated with the development and deployment of all candidate resources
                a. Costs of Energy to Consumers
                b. Life Cycle Impacts
                    i. Pollution
                    ii. Greenhouse Gas emission
                    iii. Materials
                    iv. Utility disposal
            3. Community Communication
            4. NIMBY
3. Identified Decision Points and Pathways
    a. "Getting to Zero" Carbon
        i. Motivations
            1. Regulations & Policy
                a. ETA (2019)
                    i. EPA - evolving
                b.
            2. Public Service in response to Mar 2023 IPCC report analysis - https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23
    b. Making "no regrets" decisions
        i. Evaluation of land use and community impact
        ii. Minimizing investment risk
            1. Stranded assets
                a. Loss of public trust
        iii. Maximizing investment opportunity

1. First to market w/ long term solutions
2. Public trust and sentiment

iv. Value of money vs future human life opportunities

c. Regional Planning and Coordination
   i. Organized Market Opportunities
   ii. Future Regional Transmission Operator
d. Grid Modernization (data, demand response, etc.)

4. Resources
   a. Resource Description:
      i. A *brief* description of the resource; its technical characteristics.
   b. Commercial Maturity:
      i. The TRL level or similar metric to describe the commercial maturity of the resource. How long has it been used in electric utility applications? This criteria needs to be done carefully. Some technologies have been the brunt of sabotage, business ineptness, and smear campaigns by the opponents.
   c. Staged Cost:
      i. This is a breakdown of cost by scale (if applicable). For example, solar may have a cost for 1 MW to 5 MW; and a different cost for 10 MW to 100 MW. And for storage it should also include RTE and similar variables as are in the below table.
   d. Grid Applications and Benefits:
      i. Why is this resource important to the grid? What are its applications and benefits?
   e. End of Life: From an Environmental engineering perspective, the proper heading should be "Life-Cycle Impacts"
   f. And the Sub headings should be: 1) Greenhouse Gas emissions 2)Materials 3)Utility Disposal
   g. Candidate Resources
      i. Renewable generation
         1. Solar (including community solar)
         2. Wind
         3. Geothermal
   h. No new gas of any type
   i. Energy Storage
      i. Short duration (up to 10 hr)
         1. Lithium-ion battery etc. see below charts
      ii. Inter-day & Multi-day/week Long Duration Energy Storage (LDES) - see chart 1 below
      iii. Seasonal Shifting
         1. Pumped-hydro storage, thermal energy storage, etc
   j. Not for electric
5. Potential New Resources
   a. Adoption of new technologies
   b. High Penetration of Distributed/Customer-owned Generation
   c. Firming Plans
   d. Energy efficiency and demand-response
   e. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
6. [System Needs]
7. Preferred Portfolio

a. [results of PNM modeling]
b. Potential pilot projects
c. [PNM conclusions]

DETERMINATION OF THE RESOURCE PORTFOLIO:

A. To identify the most cost-effective resource portfolio, utilities shall evaluate all supply- side resources, energy storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.

B. The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.

C. The utility shall consider and describe ways to mitigate ratepayer risk.

D. Each electric utility shall provide a summary of how the following factors were considered in, or affected,
the development of resource portfolios:

(1) load management or modification and energy efficiency requirements;
(2) renewable energy portfolio requirements;
(3) existing and anticipated environmental laws and regulations, and, if determined by the commission, the
standardized cost of carbon emissions;
(4) fuel diversity;
(5) susceptibility to fuel interdependencies;
(6) transmission or distribution constraints; and
(7) system reliability and planning reserve margin requirements.

E. Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.

1 There are numerous technologies within Long Duration Storage

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDED

△ Faces geologic constraints[1] | Not enough public datapoints to obtain a reliable value | Inter-day | Can function as both | Multi-day / week

Less Desirable → More Desirable

Duration	Energy storage form	Technology	Nominal duration, hrs	LCOS[5], $/MWh	Min. deployment size, MW	Average RTE[1], %	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 CO2[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[3]	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[4]	XX	>100	55–75	4-9

1 Demand potential / market size is limited by the requirement for specific geological formations
2 Codified based on primary technology type
3 Can function as inter-day, but organized based on longest duration potential
4 Some flow batteries under development will not work for multi-day, but it is categorized here as such given the technology's maximum duration

U.S. DEPARTMENT OF ENERGY 4

Source: Adapted from LDES Council Net Zero Power Report 2021, Wood Mackenzie Long Duration Energy Storage Report 2022, Company websites, Academic research

Welcome!

Stakeholder Engagement Meeting
(Meeting #8)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, August 31

8:30 AM – 12:30 PM Mountain Daylight Time

Optional 1:00 PM – 2:00 PM Q&A Session

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Materials available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose and Outcomes of Today's Meeting

Draft stakeholder input to action plan.

KEY OUTCOMES

- Review input to Statement of Need and priority needs
- Stakeholder understanding of modeling results to date
- Suggestions for input to Action Plan

Agenda

8:30 AM – Welcome, Purpose, Outcomes for the Meeting, & Announcements, Gridworks

8:40 AM – Overview of Input to SoN and Priority Needs Data, All Stakeholders

9:30 AM – Modeling Results, PNM Team

10:30 AM – Break

10:45 AM – Insights, Conclusion, Observations and Candidate Action Plan Ideas, All Stakeholders

12:15 AM – Summary of Actions and Next Steps, Meeting Feedback

12:30 PM – Adjourn

Optional session 1 – 2 PM for real time Q&A session for stakeholders who desire a deeper understanding of modeling results. This session will also be recorded.

Thoughts about Future Modeling Methodologies

- "IRP Modeling: Forward Thinking" Session held Aug. 22. Materials available at New Mexico Energy Planning – Gridworks
- Appreciation of stakeholders Fengyu Wang and Glenn Wikle (both New Mexico State University) and Cody Newlun (Sandia National Laboratories)

Information was shared to stimulate thoughts about the future, not to impact or influence current 2023 IRP modeling efforts or results. Results shared have not been validated by the utility or its technical consultants. Given the interest in this topic, Gridworks will recommend that such discussions begin sooner in future IRP processes.

The Current Focus is Stakeholder Input to the Action Plan

March – May | June – August | Sept – Nov

IRP Filing Dec. 15

1: Grounding and Statement of Need

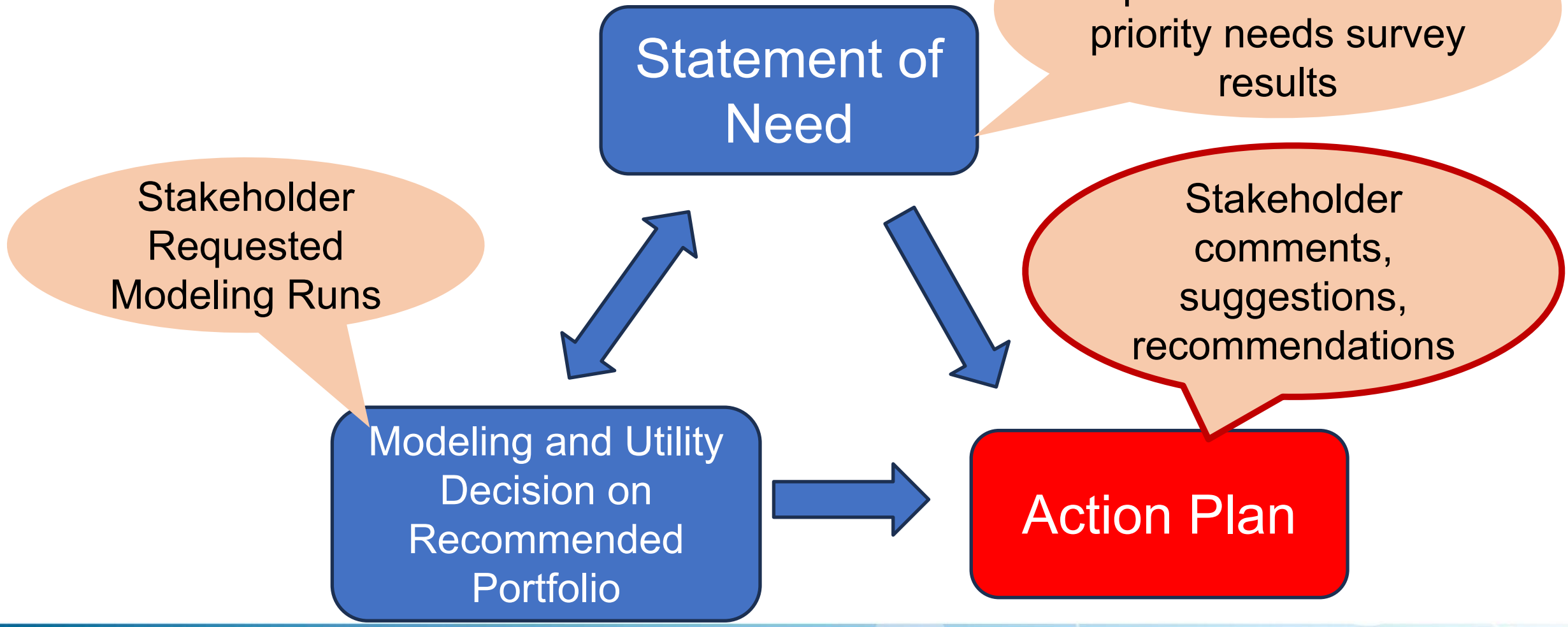
2: Model Runs and Produce Action Plans

3: IRP Reviews

SCHEDULED MEETINGS

- Sept. 14, 9 AM – 10:30 AM – Finalize stakeholder input to Action Plan
- Oct. 19, 9 AM – 10:30 AM – Review IRP elements of greatest interest to stakeholders
- Dec. 19, 9 AM – 10:30 AM – Facilitated Stakeholder Process feedback collection

Summary of Stakeholder Input Activities



Input to the Statement of Need and Priority Needs

- Review for the purpose of informing the action plan
- Input to the SoN – Michael Barrio
- Credit to the working group members:
  - Athena Christodoulou, Barbara Chatterjee, Daren Zigich, Michael Kenney, Cydney Beadles, Jim DesJardins, Chadette Pfaff
- Priority Needs survey summary
- Hear from PNM regarding SoN template
- Discussion

1. **Introduction**
2. **Vision and Goals**
    a. Identify resources
    b. Goals
        i. Support Rapid Decarbonization & Electrification
        ii. Reliability and Resilience: Utility's Obligation to Serve
            1. Minimum Reserve Requirements
            2. Reliability Standards
            3. Swift recovery from climate or security threats
        iii. Public Interest and Equity
            1. Responsibilities to Ratepayers and Stakeholders (affordability, availability to underserved communities, climate justice, impacts on workforce)
            2. Costs associated with the development and deployment of all candidate resources (cost of energy to customers, life cycle impacts)
            3. Improve Communication to the General Public
3. **Identified Decision Points and Pathways**
    a. "Getting to Zero" Greenhouse Gas
        i. Motivations
            1. Regulations & Policy (ETA, EPA GHG standard, NM methane rule)
            2. Public service in response to March 2023 IPCC report analysis summary for policymakers
            3. Recognition of Company's corporate commitment to zero carbon by 2040

4. Identified Decision Points and Pathways

a. Making "no regrets" Decisions (evalland use and community impact, broad inclusion of stakeholders, minimize investment risk, max infrastructure investment opportunity)
    1. First to market w/ long term solutions
    2. Public trust and sentiment
    ii. Value of money vs future human life opportunities

b. Evaluate & Pursue Regional Planning and Coordination
    i. Organized market opportunities
    ii. Future regional transmission operator (RTO) opportunities

d. Modernizing the Grid
    i. Policy needs to support reaching carbon targets, DSM (demand side management), DG (distributed generation) and other behind-the-meter resources)
    ii. Demonstrate transition from old to new grid structure
    iii. Assessment of impact of all areas of behind-the-meter resources.

5. Resources

a. Resource Description:
   i. A *brief* description of the resource; its technical characteristics.
b. Commercial Maturity:
   i. The Technology Readiness Level (TRL) or similar metric
c. Staged Cost:
   i. This is a breakdown of cost by scale (if applicable). Grid Applications and Benefits
   ii. Why is this resource important to the grid? What are its applications and benefits?
d. Status of each resource in the modeling process (i.e., included, not included with reason why, not available for inclusion for lack of data, etc.)
e. Candidate Resources
   i. Base technologies (wind, solar, 4-hr li-ion storage, energy efficiency, demand response)
   ii. Other Resources (Pumped hydro storage 70-hr, Pumped hydro storage 8-hr, Iron-air storage, Compressed Air Energy Storage, Liquified Air Energy Storage, Flow battery, Thermal storage, Combustion Turbines, Linear generators, Carbon capture retrofit, NET power plant , Hydrogen

6. **Potential New Resources**
    a. Adoption of new technologies
    b. High Penetration of Distributed/Customer-owned Generation
    c. Energy efficiency and demand-response
    d. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
    e. Describe long duration storage options not considered (reference chart 1 in "Items for Discussion" below)
7. **[System Needs]**
8. **Preferred Portfolio - Refer to appendix of resource evaluation**
    a. [results of PNM modeling]
    b. Potential pilot projects
    c. [PNM conclusions]

Stakeholders Reinforced Reliability and Affordability as Priority

NUMBER OF PEOPLE LISTING THE NEED AS PRIORITY	NEED
12	Reliability and Resiliency
10	Affordability (life cycle cost of portfolio)
8	Environmental Attributes (e.g. water use, air quality) + non carbon emissions
7	Exceeding State Carbon Reduction Requirements
7	Climate Justice/Energy Justice
6	Fuel Diversity and Fuel Security
5	Exceeding State RE Requirements
5	Maximizing EE, Demand Response and DSM Technology
4	Scalability of Technology
3	Technology Diversity
2	Research & Demonstration of New Technology
1 – OTHER, WRITE IN	Minimizing future reliance on fossil fuels and stranded costs of fossil fuel infrastructure

2 respondents listed affordability as their highest priority need.

Fourteen valid responses to the survey were received.

Themes and Outline - Statement of Need

PNM TEAM

GRIDWORKS

Modeling Results Discussion

- PNM Team presentation, 50 minutes
  - Please write questions of clarification in the chat
  - Responses, 10 minutes
- Follow up questions
  - Additional questions of modeling results interpretation will be addressed from 1:00 PM – 2:00 PM today.
  - Questions regarding modeling assumptions, inputs, processes, alternate scenarios, factors/weighting, etc. can be entertained during the IRP public comment period.

Modeling Results

PNM TEAM

GRIDWORKS

Reflections, Insights, Observations, Action Plan Ideas

Per the IRP Rule, 17.7.3.11 utility's action plan shall:

1) detail the specific actions the utility shall take to implement the IRP spanning a three year period following the filing of the utility's IRP;
2) detail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission; and
3) include a status report of the specific actions contained in the previous action plan

- The utility creates the action plan, stakeholder input is to be considered
- Ideas on topics beyond the items list above will be documented but may not be within IRP scope.

Action Plan Suggestions Offered to Date

Ideas offered by stakeholders during the June 29 Meeting:

- Changing fossil fuel plants to long duration energy storage as environmental justice for impacted communities
- Collect distribution feeder level reliability metrics to understand reliability equity
- Initiate public education effort regarding electricity sector changes and IRP process

Items introduced during stakeholder modeling run request process:

- Explore availability of landfill gas as supplementary/replacement fuel
- □ Include extreme weather considerations during next IRP cycle
- Explore benefits from participation in organized regional market, and from participation under extreme weather scenarios
- Incorporate consideration of correlated gas outages in next IRP cycle

Process for Input to the Action Plan

SMART ACTIONS

S □ Specific

M □ Measurable

A □ Achievable

R □ Realistic

T □ Timetable

- Enter into chat during today's meeting
- Complete form(s) → https://forms.gle/JVaAstwxakYXcFAU6 by noon on Sept. 13
- If you do not have access to google docs, send an email with "PNM ACTION PLAN SUGGESTION" in the email subject to info@gridworks.org by noon on Sept 13. Please include your suggestions, your name, and your organization.
- All suggestions will be summarized and discussed during Sept. 14 meeting.

September 14 Meeting Will Focus on Action Plan

- Sept. 14, 9 – 10:30 AM ACTION PLAN INPUT FINALIZED
- Oct. 19, 9 – 10:30 AM DISCUSS UNRESOLVED ISSUES
- Dec. 15 IRP is filed by PNM
- Dec. 19, 9 - 10:30 AM Final stakeholder meeting to collect input regarding how you experienced the process

For those with modeling results questions, please reconvene at 1 PM MDT.

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

PNM 2023-2042 IRP: Modeling Results Update

FACILITATED STAKEHOLDER MEETING

AUGUST 31, 2023

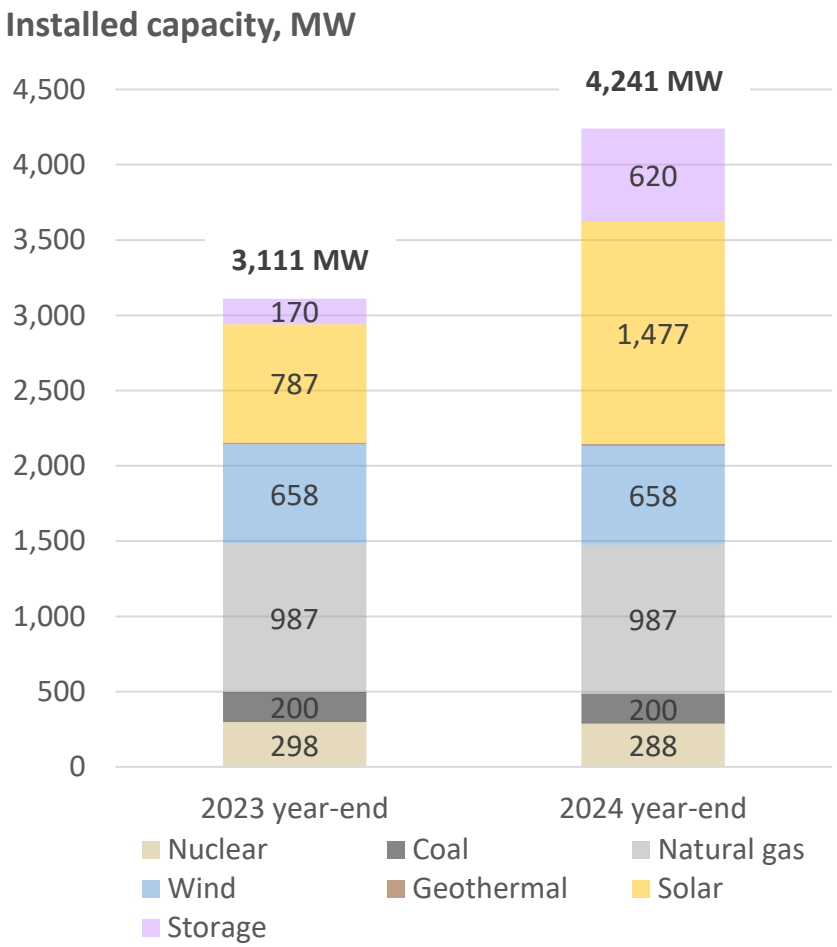


DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

PNM'S EXISTING RESOURCE PORTFOLIO AND NEAR-TERM RESOURCE ADEQUACY



2024 capacity

Storage: 620

Solar: 1,477

Wind: 658

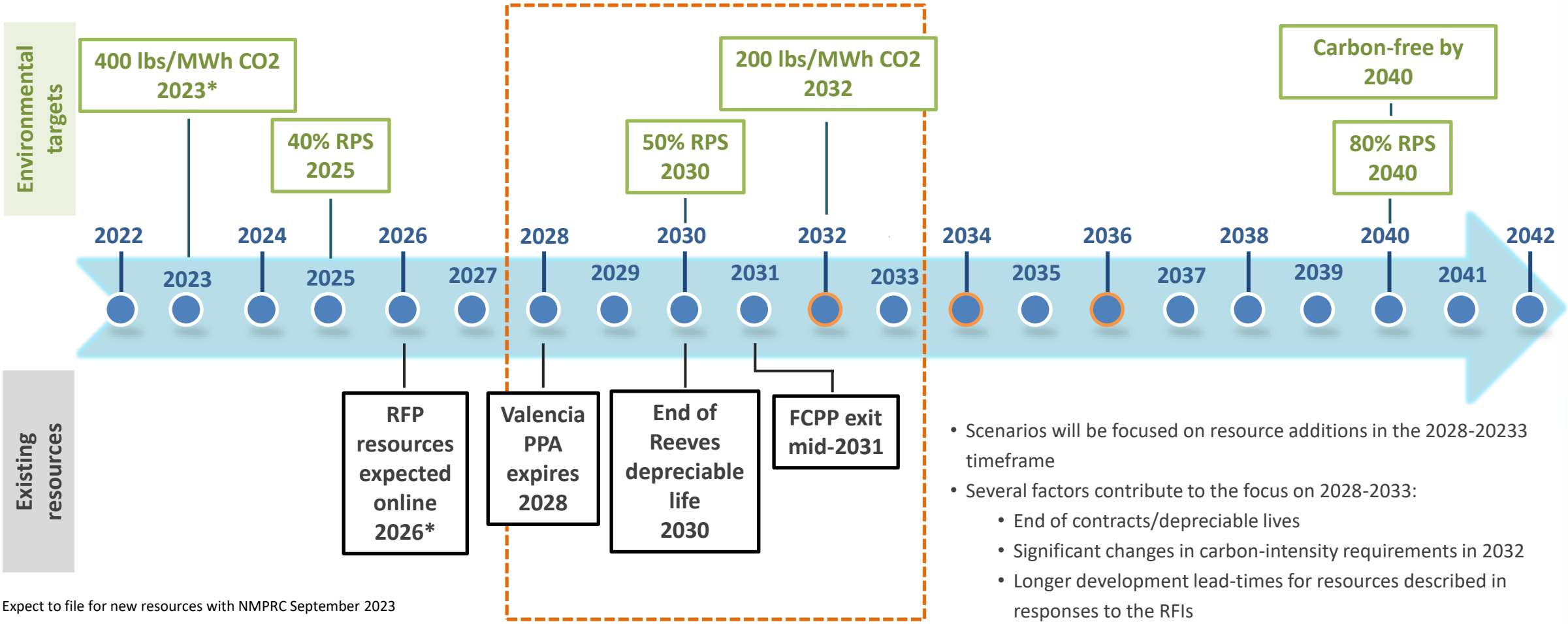
Natural Gas: 987

Coal: 200 MW

Nuclear: 288 MW share of Palo Verde

- Near term additions include 400 MW of solar and 170 MW of storage by the end of 2023
- By year-end 2024, PNM will have added an additional 690 MW of solar and 450 MW of storage
- RFPs for 2026-2028 are currently ongoing

KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS POINT TO 2028-2033 AS A CRITICAL PERIOD



- Scenarios will be focused on resource additions in the 2028-20233 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs

* Expect to file for new resources with NMPRC September 2023

TECHNOLOGIES AVAILABLE IN PHASES 1-2

Base technologies only

PNM relies on solar, wind, and storage (lithium-ion) to meet future need and carbon emission reduction goals



Base + long-duration Storage

PNM makes a commitment to add long-duration storage in the 2028-2033 timeframe to meet future capacity need and facilitate clean energy transition



Base + natural gas

PNM allows new build of natural gas resources that will be converted to utilize hydrogen in 2040



Base + wind expansion

PNM seeks strategic transmission expansion in the late 2020's/early 2030s to integrate a large quantity of wind resources



Base + carbon capture

PNM relies on carbon capture and sequestration technologies to meet future capacity need and facilitate clean energy transition



Base + H2/early gas conversion

PNM pilots use of hydrogen before 2040 by creating green hydrogen via electrolysis for use in new or existing CTs



Energy efficiency and demand response included in all scenarios

DISCLAIMER - RESULTS ARE PRELIMINARY DRAFT

- PNM has incorporated numerous updates to its modeling in this IRP cycle
- While we have taken every effort to ensure the validity of these techniques, please understand that the results we will discuss are considered preliminary draft results and will likely change as we continue to refine the analysis
- In previous IRP cycles we would not present results before a full draft of the IRP was ready; we have made efforts to get stakeholders involved earlier in this IRP cycle, starting the public advisory process earlier than ever
- In order to maximize stakeholder involvement, presenting preliminary results and inviting feedback earlier is equally important
- At this stage, we will highlight some of the key trends we see so far, and some of the areas that require further study and refinement

PHASE 1 SCENARIOS EXPLORE ATTRIBUTES OF A VARIETY OF TECHNOLOGIES

Scenario Name	Scenario-Specific Assumptions
Base technologies	Only solar, storage, and EE, DR allowed through 2032
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 energy 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 hydrogen-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 hydrogen-fueled CT & ~750 MW electrolyzer added in 2031

- In Phase 1, technology-specific scenarios are screened under the following conditions:
  1. **CT&P future (capacity expansion run)**
     a) P50 load 8760 production cost run
     b) Extreme weather load 8760 production cost run
- **This approach gives PNM the ability to evaluate scenarios based on:**
  - Overall cost
  - Ability to accommodate extreme weather load
- All portfolios include option to add base technologies (including DR and EE) at any time
- ***EnCompass modeling targets PRM, RPS, and carbon-intensity inputs***

PNM Talk to us. PNM.com

PHASE 2 SCENARIOS EXPLORE SYNERGIES BETWEEN TECHNOLOGIES

Scenario Name	Scenario-Specific Assumptions
PHS 70-hr + CT	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready CTs allowed
PHS 70-hr + CT + wind	300 MW of pumped storage (70-hr) by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
PHS 70-hr + Linear gen.	300 MW of pumped storage (70-hr) by 2032; new hydrogen-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 hydrogen-ready CTs allowed
PHS 8-hr + CT + wind	300 MW of pumped storage (8-hr) by 2032; new hydrogen-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 energy storage by 2032; new hydrogen-ready CTs allowed
IAS + CT + wind	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready CTs allowed; new wind beginning in 2028
IAS + Linear gen.	At least 100 MW of iron air energy storage by 2032; new hydrogen-ready linear generators allowed
IAS + Afton CCS	At least 100 MW of iron air energy 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 energy storage and at least 100 MW liquid air energy storage by 2032
Green hydrogen + wind	~250 MW hydrogen-fueled CT & ~750 MW electrolyzer added in 2031; new wind beginning in 2028
Flow + CT	At least 100 MW of flow batteries (10-hr) by 2032; new hydrogen-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	Model has option to add base technologies, CTs (2026+), and any long-duration storage technology (2028-2033)
Base tech + LDES	Model has option to add base technologies and any long-duration storage technology (2028-2033)

- In Phase 2, PNM designed more complex portfolios consisting of two or more RFI technologies – the intent is to explore synergistic effects of combining operating characteristics
- All portfolios include option to add base technologies (including DR and EE) at any time
- Scenarios are screened under the same conditions as in Phase 1
- ***EnCompass modeling targets PRM, RPS, and carbon-intensity inputs***

PNM Talk to us. PNM.com

PNM MODELING RESULTS UPDATE – PHASES 1-2

Near-final results

PROPOSED PORTFOLIO EVALUATION CRITERIA: PHASES 1-2

RELIABILITY (INITIAL HURDLE)

- Check to ensure unserved energy is within a reasonable range
- Compare EnCompass portfolio EUE from extreme weather simulations to EUE from a SERVM tested reliable portfolio
- If EnCompass portfolio EUE falls within range of EUE from SERVM reliable portfolio, then portfolio/technology passes reliability test

COST (SCORE COMPONENT)

- Measured as present Value of Revenue Requirement, which reflects total cost of portfolio across study period
- Comparison of overall costs

TECHNOLOGY RISK (SCORE COMPONENT)

- Measured as a weighted average Technology Readiness Level
- Each portfolio assigned a weighted average TRL based on the 2040 firm capacity breakdown
- Comparison of dependence on less proven technologies on a firm capacity basis

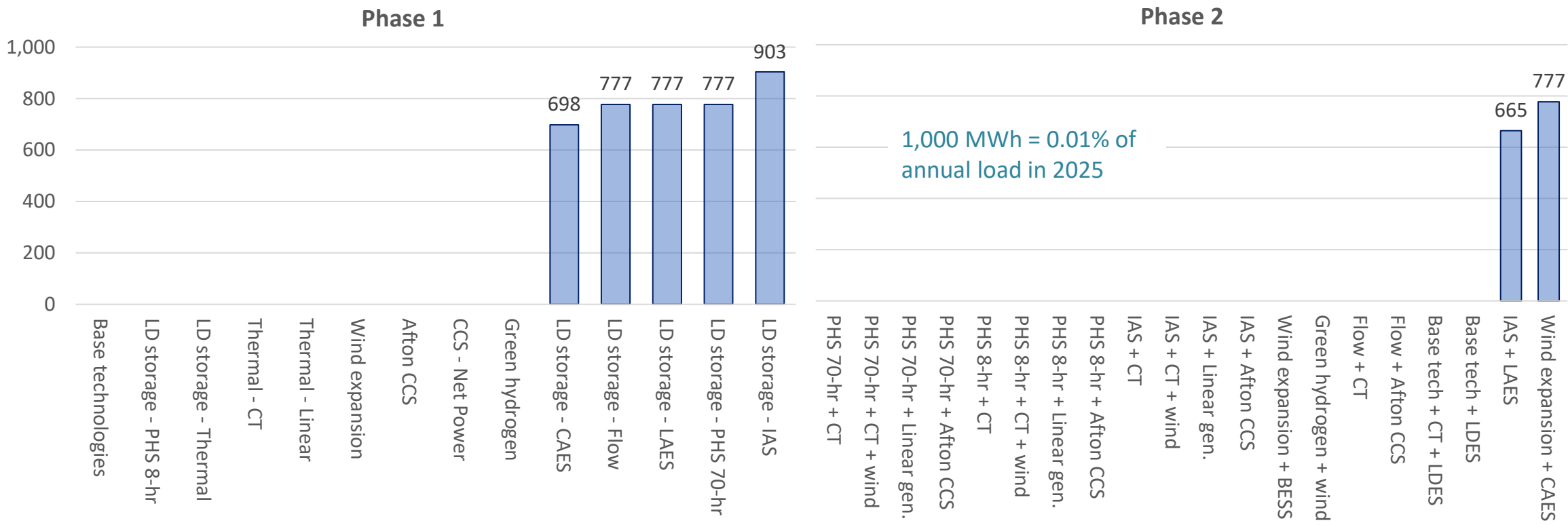
CARBON EMISSIONS (SCORE COMPONENT)

- Measured as NPV of total carbon emissions across study period (10% discount factor)
- Comparison of carbon emissions associated with scenario-specific combination of technologies
- Earlier abatement improves CO2 metric

Near-final results

PORTFOLIOS RANKED BY UNSERVED ENERGY UNDER EXTREME WEATHER LOAD CASE

2040 unserved energy under extreme weather load case, MWh

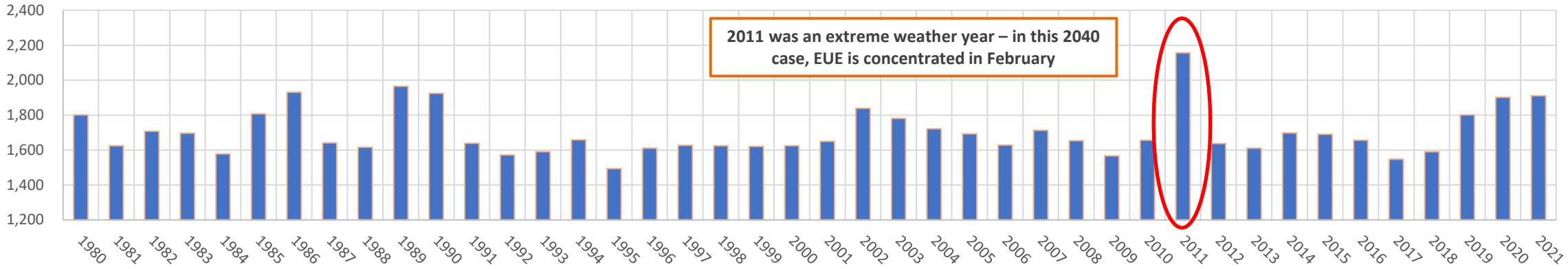


PNM Talk to us. PNM.com

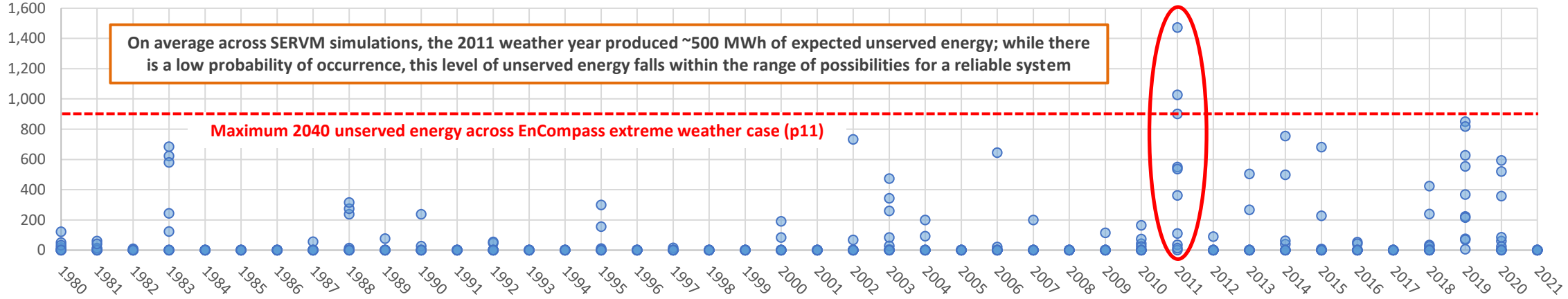
Preliminary results

PUTTING UNSERVED ENERGY IN CONTEXT: 2040 RESULTS FROM 0.1 LOLE CASE (BASE TECHNOLOGIES ONLY)

2040 peak February load by weather year, MW



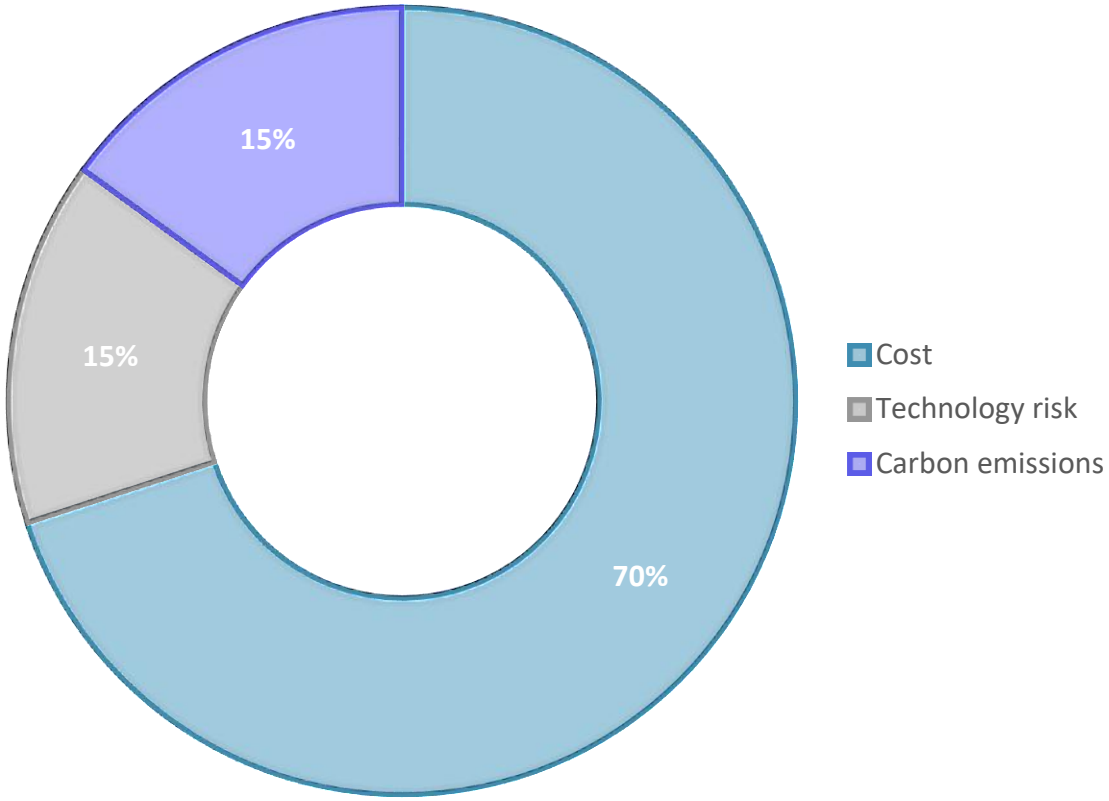
2040 EUE across 10 simulations by weather year, MWh



Talk to us.

SCORING MATRIX APPROACH AND POTENTIAL CRITERIA WEIGHTING (PHASE 1 & 2)

Preliminary PNM evaluation criteria weighting for overall portfolio score

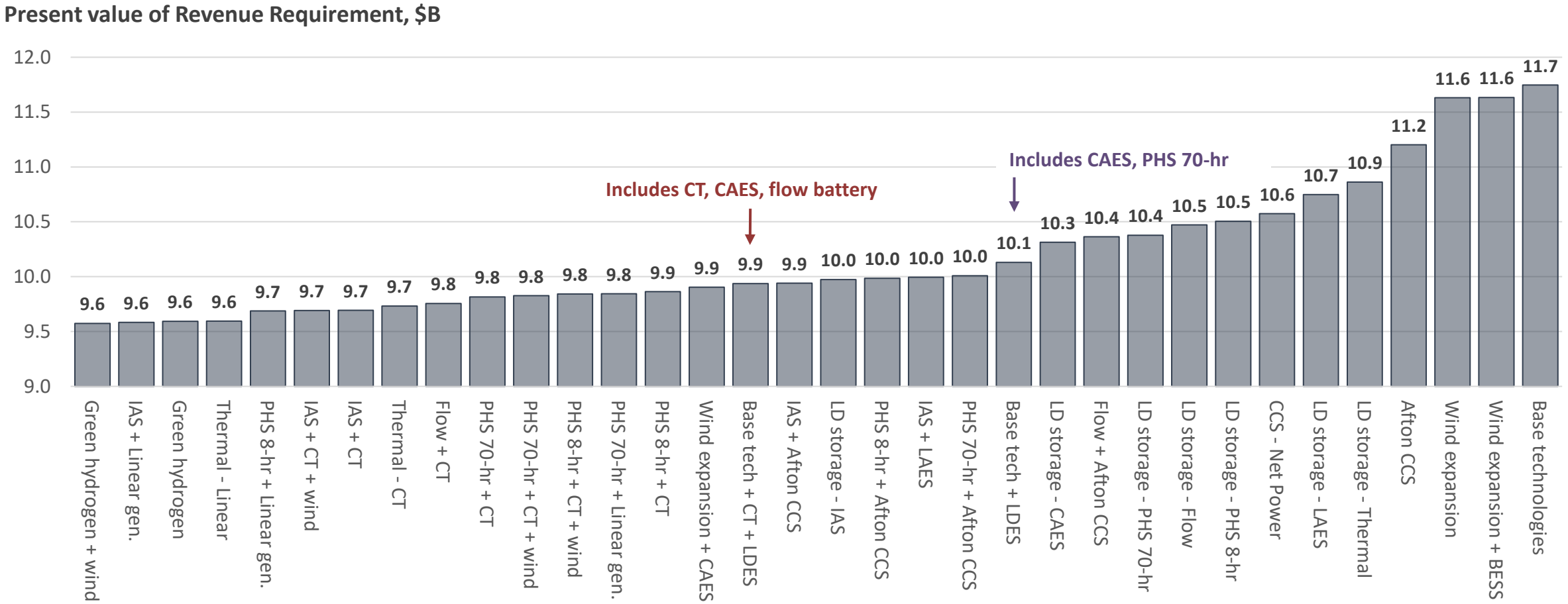


All portfolios meet carbon intensity and RPS requirements

- Each portfolio is given a score for each metric
- Scores range from 1 to 10, with 1 being the highest possible score
- For example, the portfolio with the lowest PVRR across all portfolios receives a score of 1 for the PVRR metric, the portfolio with the highest PVRR receives a score of 10
- The scores are then weighted and summed for a final portfolio score; portfolios with lower scores are preferred

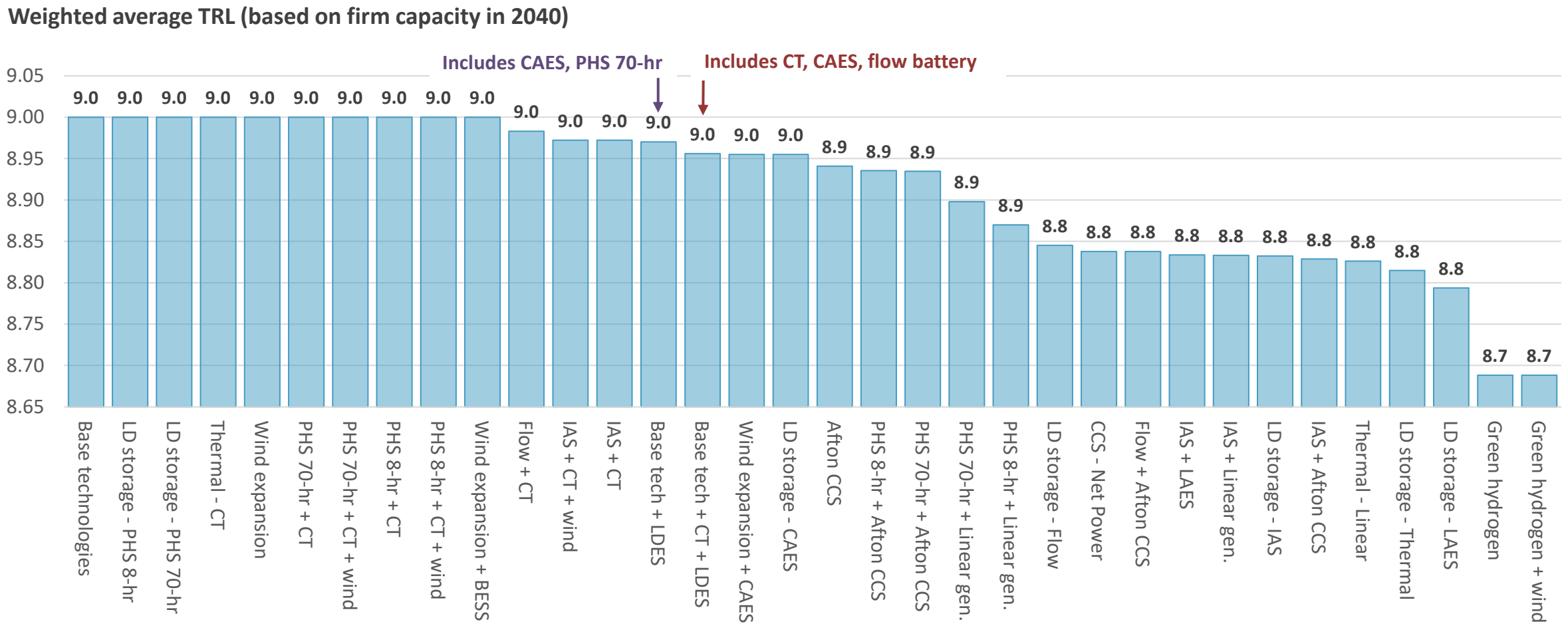
Near-final results

PORTFOLIOS RANKED BY PRESENT VALUE OF REVENUE REQUIREMENT



Near-final results

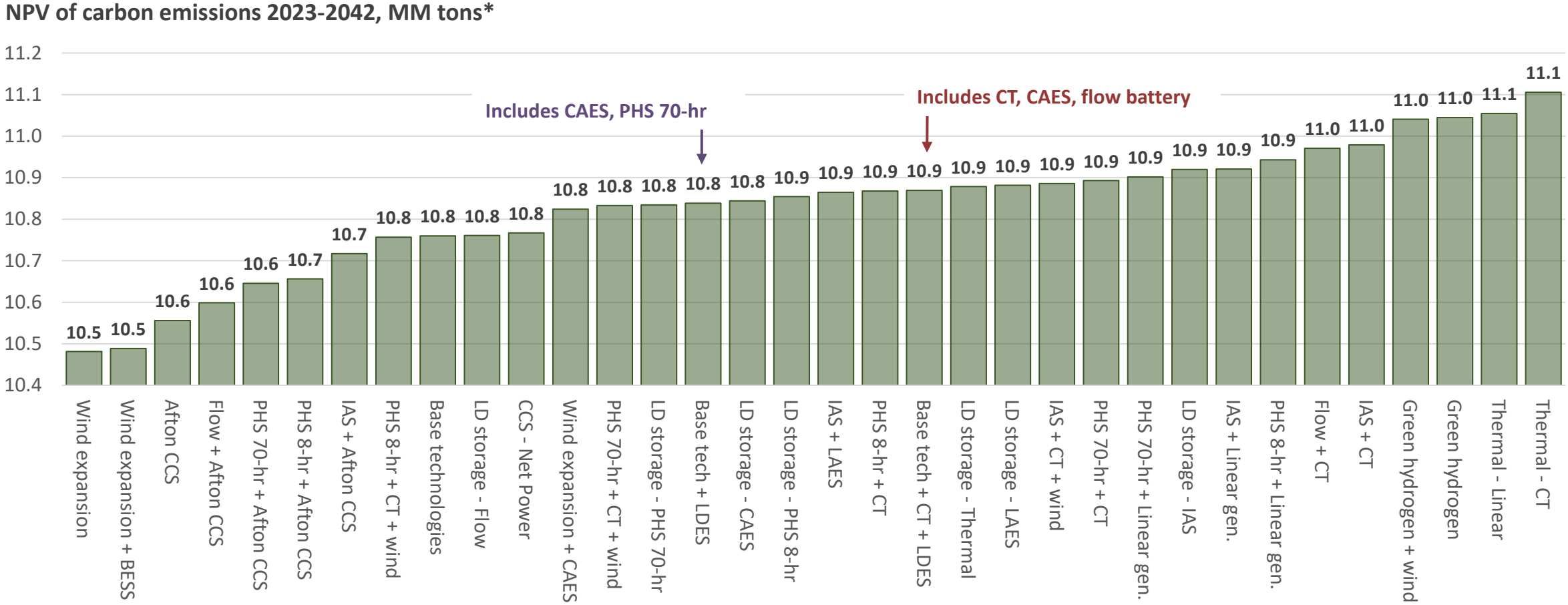
PORTFOLIOS RANKED BY WEIGHTED AVERAGE TECHNOLOGY READINESS LEVEL



PNM Talk to us. PNM.com

Near-final results

PORTFOLIOS RANKED BY TOTAL CARBON EMISSIONS 2023-2042



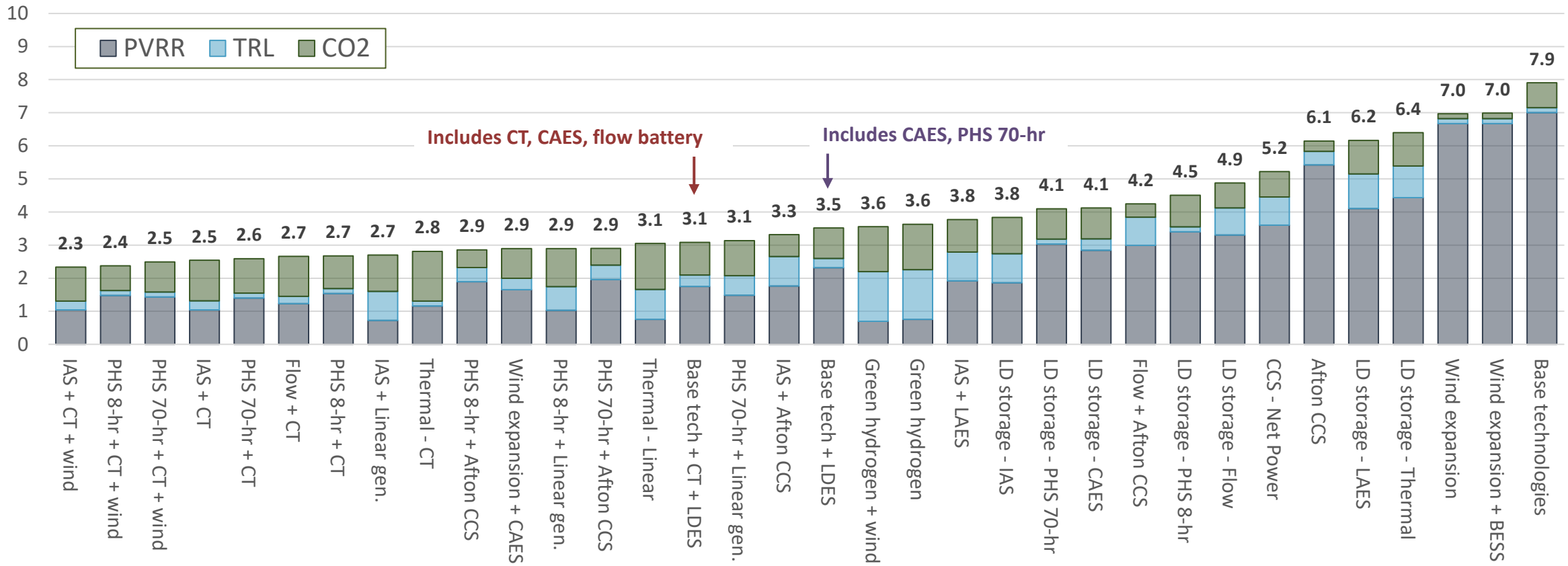
** 10% discount rate used for NPV calculation*

PNM Talk to us. PNM.com

Near-final results

SCORED PORTFOLIOS USING PRELIMINARY PNM CRITERIA AND WEIGHTING SCHEME

Total score breakdown by weighted component

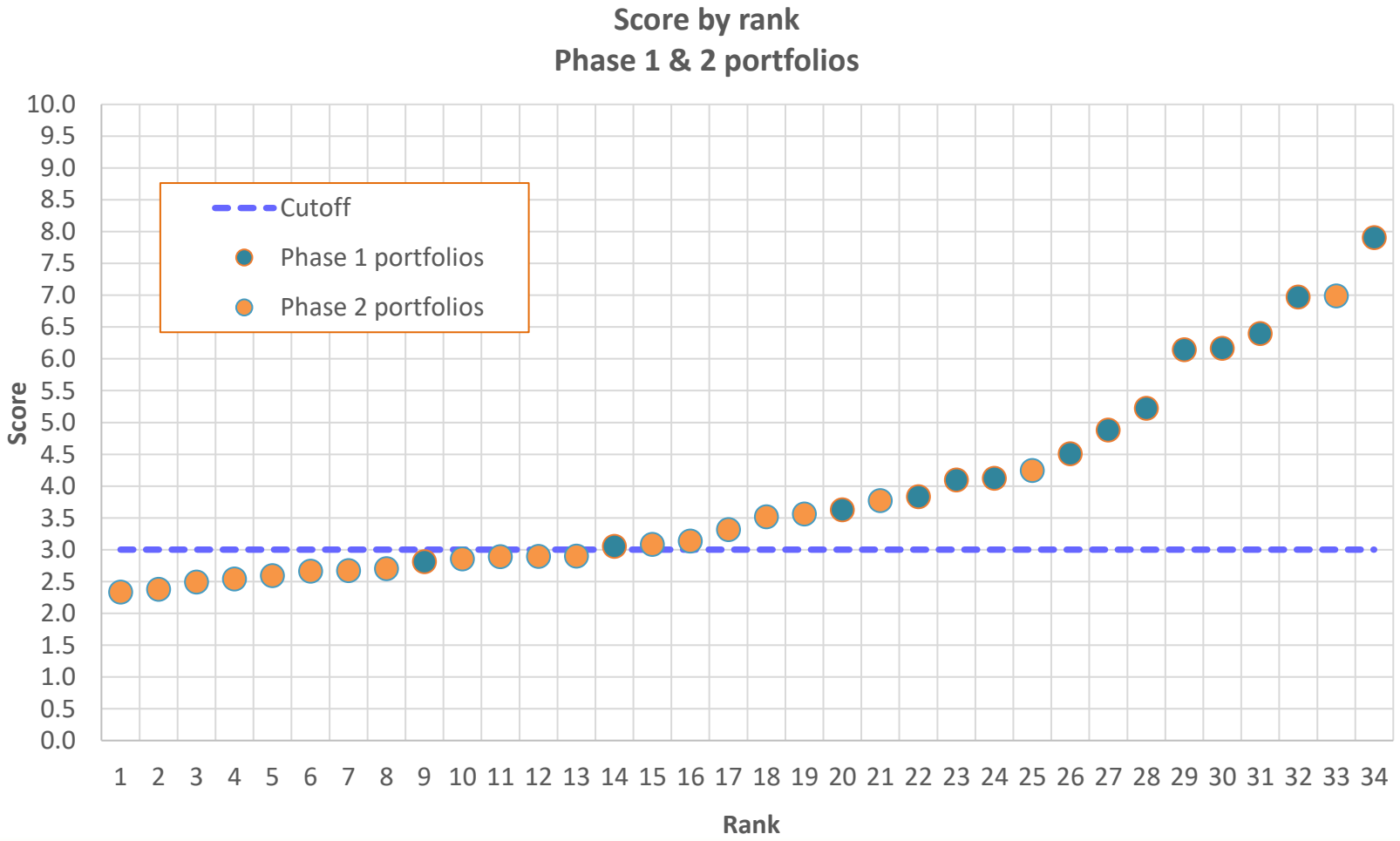


Talk to us.

Near-final results

PHASES 1-2 INFORM PHASE 3 TECHNOLOGY SELECTION

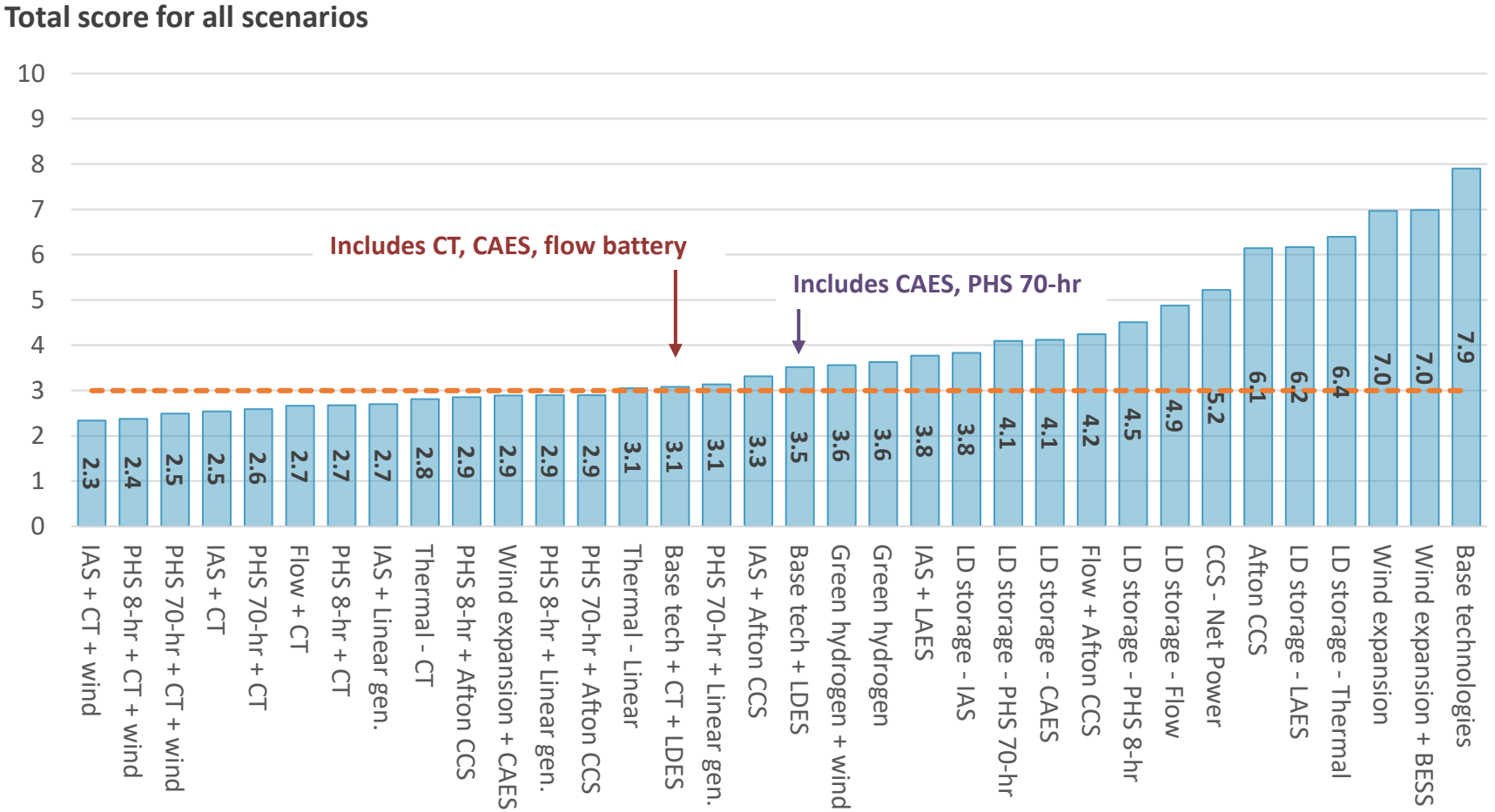
- Portfolio scores across Phases 1-2 indicate a “cutoff point”
- All unique technologies included in portfolios below the cutoff point will be included in Phase 3 modeling
- Phase 3 modeling will focus on “kitchen sink” scenarios in which EnCompass can select from a wide array of technologies selected from Phases 1-2
- Results from Phases 1-2 will help to contextualize results from Phase 3, and provide good comparison points



PNM Talk to us. PNM.com

Near-final results

PHASE 3 TECHNOLOGY SELECTION



Unique technologies selected for Phase 3 modeling:

- CAES
- Flow battery
- PHS (8-hr & 70-hr)
- IAS
- CT
- Linear generator
- Wind expansion
- Afton CCS (Afton retrofit)

PNM Talk to us. PNM.com

Near-final results

FIVE SCENARIOS FOR PHASE 3 MODELING

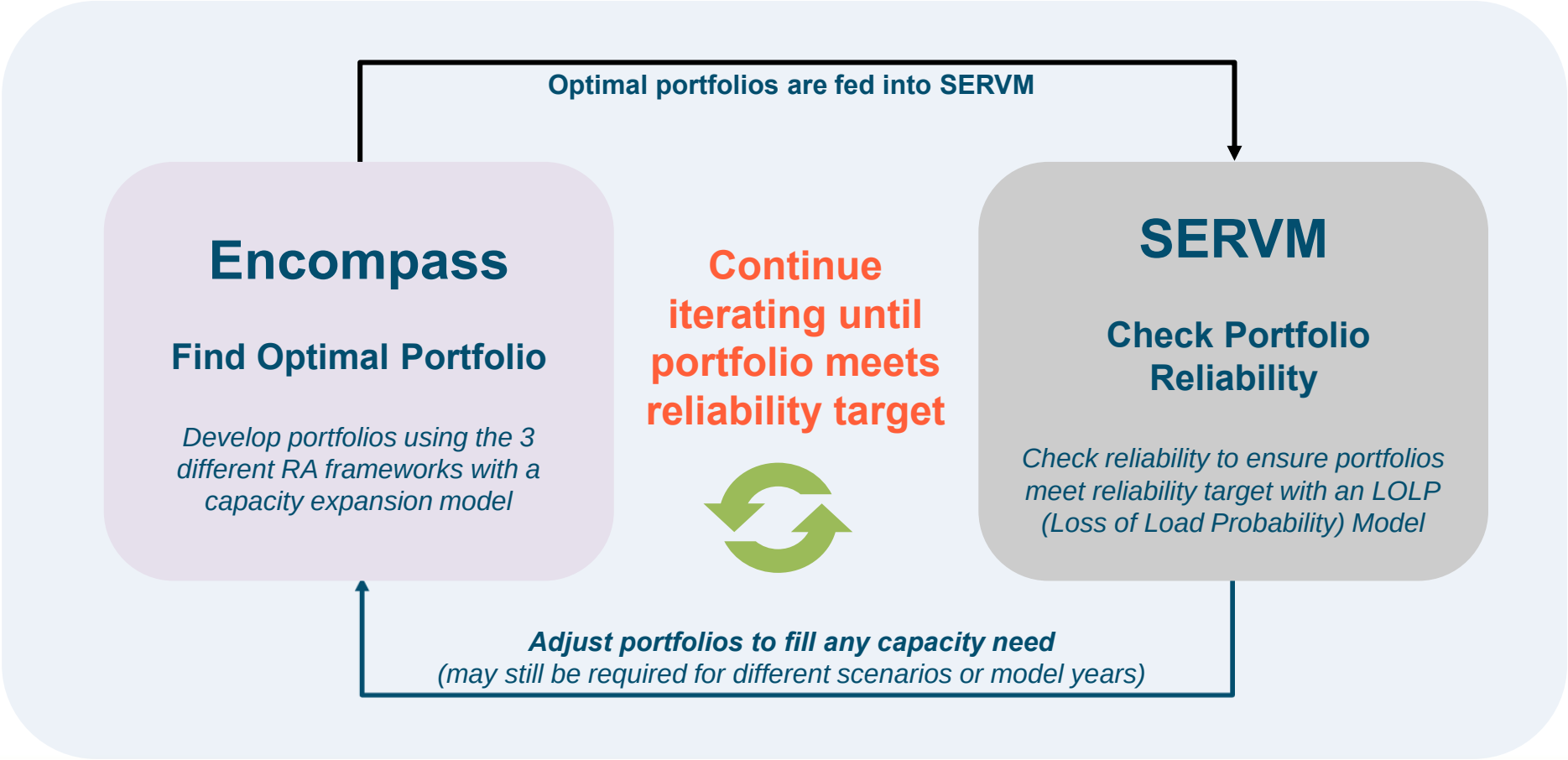
Base technologies only	Base technologies + CTs	Base technologies + all LDES *(stakeholder scenario)*	Base technologies + all LDES + CTs	Base technologies + LDES + NG + CCS
Resource options	**Resource options**	**Resource options**	**Resource options**	**Resource options**
• Solar • Wind • 4-hr storage • EE/DR	• Solar • Wind • 4-hr storage • EE/DR • CT	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 70-hr • PHS 8-hr • IAS • LAES • Thermal storage	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 70-hr • PHS 8-hr • IAS • LAES • Thermal storage • CT	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 8-hr • PHS 70-hr • IAS • CT • Linear generator • Wind exp. • Afton CCS

PNM MODELING RESULTS PHASE 3

Near-final results

PORTFOLIOS DEVELOPED IN ENCOMPASS SHOULD BE CALIBRATED TO COMMON RELIABILITY STANDARD

Portfolio calibration process for each RA framework to ensure each portfolio meets 0.1 LOLE

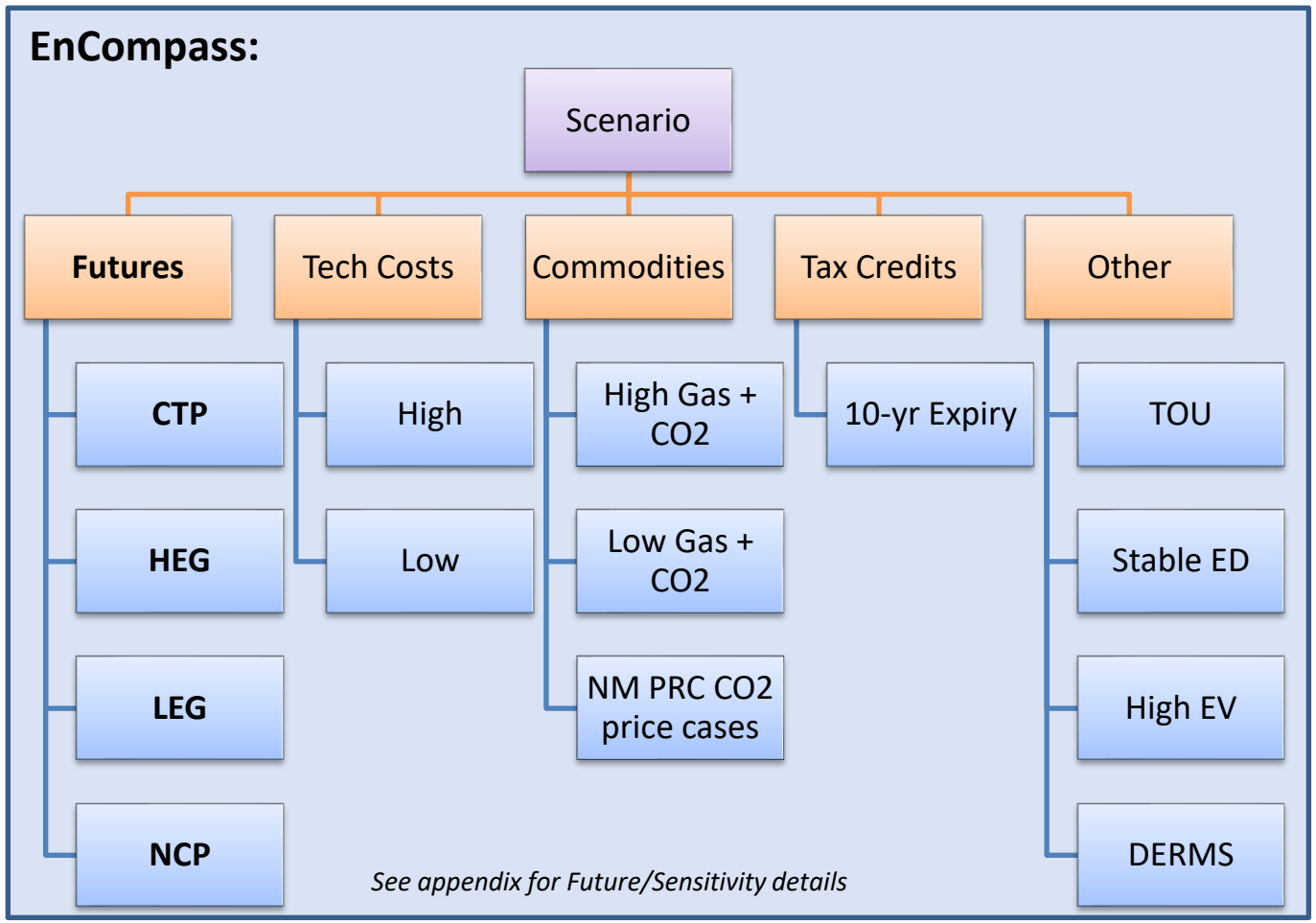


PNM Talk to us. PNM.com

Near-final results

PHASE 3 MODELING

EnCompass:



SERVM:

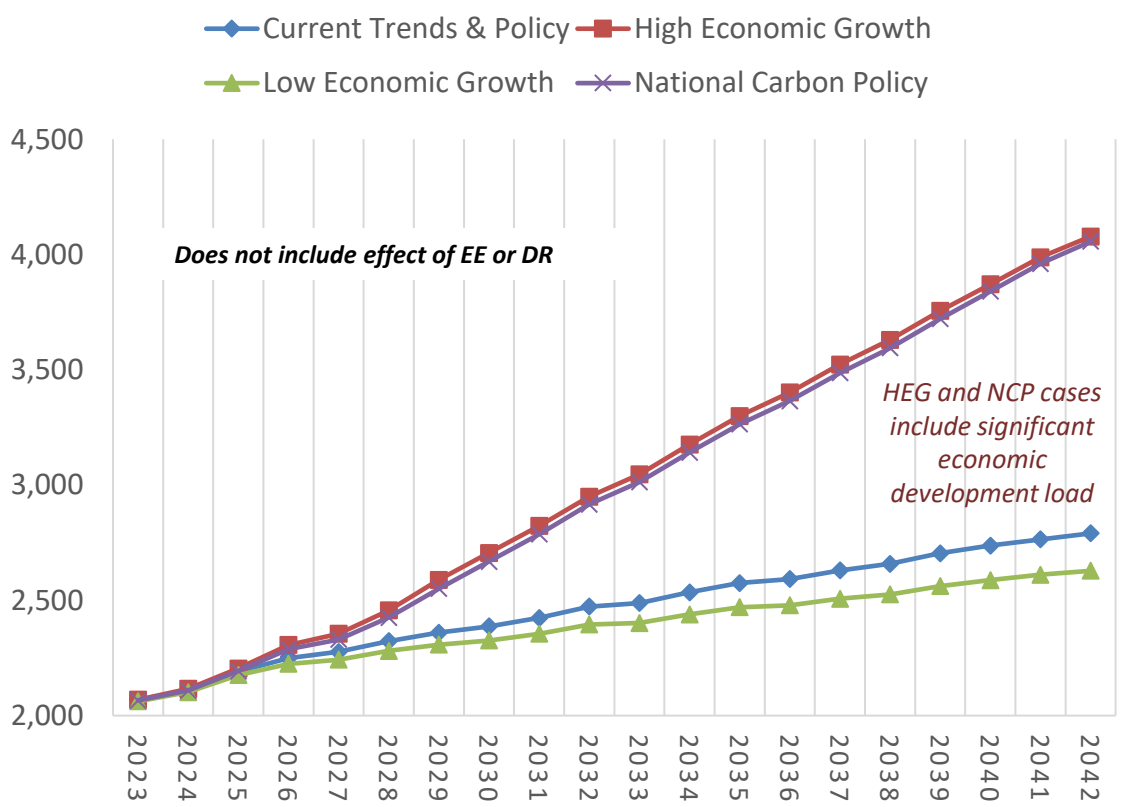
CTP & HEG cases run for selected scenarios to determine:

- LOLE meets ~0.1 target
- EUE for portfolio

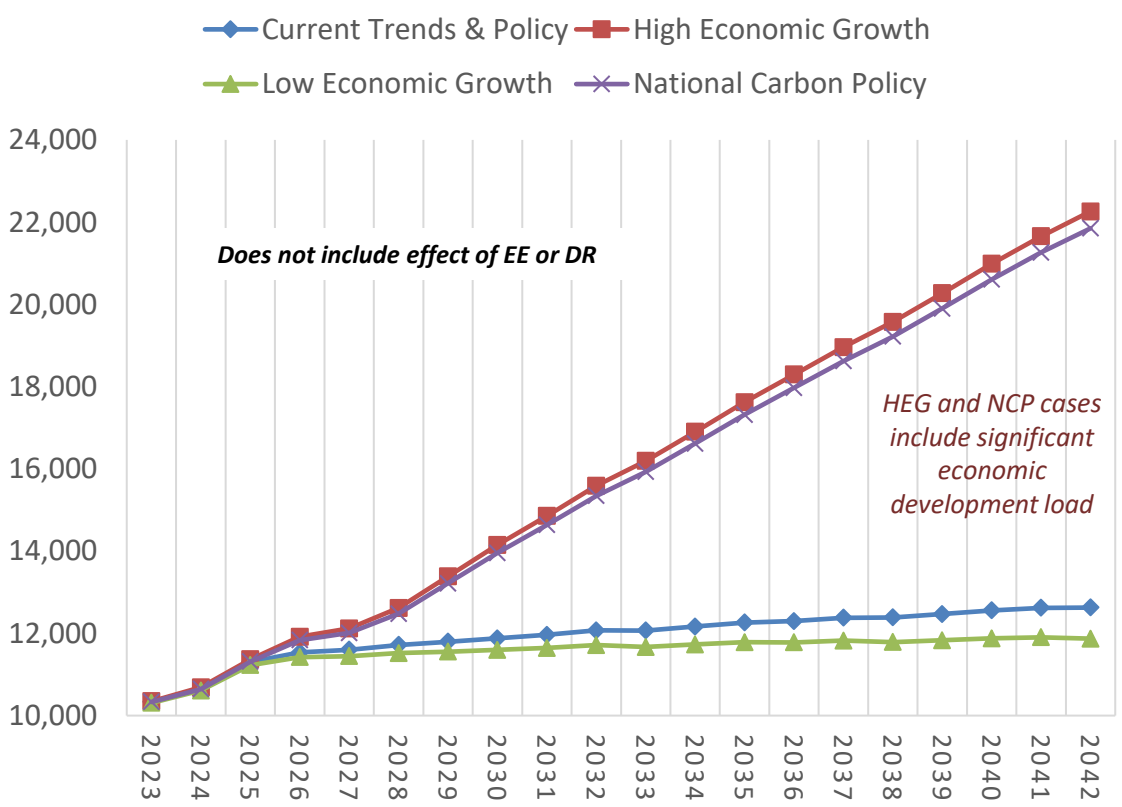
Near-final results

PEAK LOAD AND ENERGY BY YEAR

ANNUAL COINCIDENT PEAK, MW



ANNUAL ENERGY, GWH



PHASE 3 EVALUATION

Current Trends & Policy	Base tech	Base tech + CT	Base tech + LDES	Base tech + LDES + CT	Base tech + LDES + NG + CCS
High Economic Growth	Base tech	Base tech + CT	Base tech + LDES	Base tech + LDES + CT	Base tech + LDES + NG + CCS
Low Economic Growth	Base tech	Base tech + CT	Base tech + LDES	Base tech + LDES + CT	Base tech + LDES + NG + CCS
National Carbon Policy	Base tech	Base tech + CT	Base tech + LDES	Base tech + LDES + CT	Base tech + LDES + NG + CCS

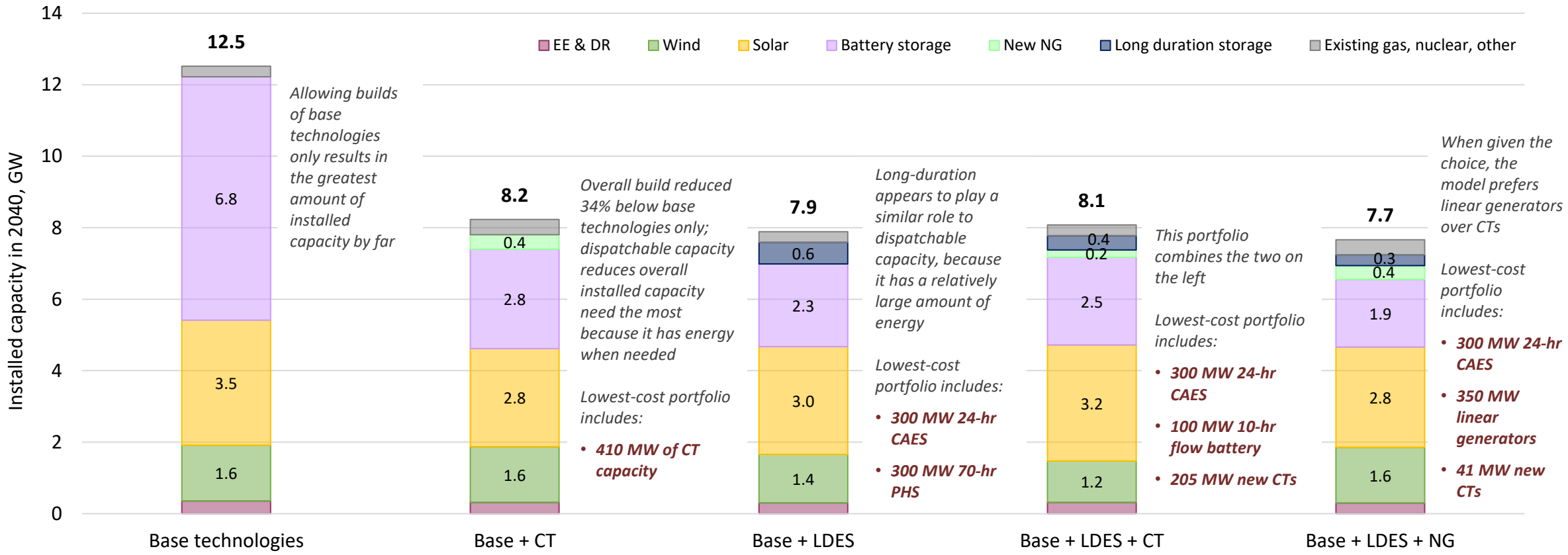
Changes to evaluate across futures and sensitivities:

- Under a given future, how does the portfolio makeup change when we allow the model different technology choices?
- Under a given future what are the reliability metrics associated with a given portfolio?
- How do reliability metrics change across portfolios/as certain technologies are added?
- What are the common characteristics/qualities that help system in each case?

Near-final results

CURRENT TRENDS & POLICY – 2040 INSTALLED CAPACITY ACROSS SCENARIOS

Fewer options — *The more options EnCompass has, the lower the total build* — *More options*



Allowing builds of base technologies only results in the greatest amount of installed capacity by far

Overall build reduced 34% below base technologies only; dispatchable capacity reduces overall installed capacity need the most because it has energy when needed

Lowest-cost portfolio includes:

- ***410 MW of CT capacity***

Long-duration appears to play a similar role to dispatchable capacity, because it has a relatively large amount of energy

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***300 MW 70-hr PHS***

This portfolio combines the two on the left

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***100 MW 10-hr flow battery***
- ***205 MW new CTs***

When given the choice, the model prefers linear generators over CTs

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***350 MW linear generators***
- ***41 MW new CTs***

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519

Portfolios without dispatchable resources exhibit significantly higher cost. Variations in cost among scenarios with new firm resources are relatively small, but lowest cost is Base + LDES + NG (the scenario with the greatest number of resource options)

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519
NPV CO2, MM tons	10.8	11.1	10.8	10.9	10.7

Portfolios without natural gas additions achieve lower CO2 NPV

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519
NPV CO2, MM tons	10.8	11.1	10.8	10.9	10.7
Weighted avg. TRL (firm 2040)	9.00	9.00	8.97	8.96	8.87

Portfolios with the lowest TRL have the greatest amount of resource options between which to optimize

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519
NPV CO2, MM tons	10.8	11.1	10.8	10.9	10.7
Weighted avg. TRL (firm 2040)	9.00	9.00	8.97	8.96	8.87
Loss of load expectation (2032), days per year with a loss of load	**0.04**	**0.06**	**0.08**	**NA**	**0.09**

All portfolios reliable in 2032 – base technologies only portfolio far below LOLE target of 0.1

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Talk to us.

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519
NPV CO2, MM tons	10.8	11.1	10.8	10.9	10.7
Weighted avg. TRL (firm 2040)	9.00	9.00	8.97	8.96	8.87
Loss of load expectation (2032), days per year with a loss of load	**0.04**	**0.06**	**0.08**	**NA**	**0.09**
Loss of load expectation (2040), days per year with a loss of load	**0.02**	**0.11**	**0.27**	**NA**	**0.05**

LDES portfolio does not achieve 0.1 LOLE target in 2040; conversely, base technologies portfolio seems overbuilt

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519
NPV CO2, MM tons	10.8	11.1	10.8	10.9	10.7
Weighted avg. TRL (firm 2040)	9.00	9.00	8.97	8.96	8.87
Loss of load expectation (2032), days per year with a loss of load	**0.04**	**0.06**	**0.08**	**NA**	**0.09**
Loss of load expectation (2040), days per year with a loss of load	**0.02**	**0.11**	**0.27**	**NA**	**0.05**
Expected unserved energy (2040), MWh per year	20	30	139	NA	15

LDES portfolio has highest EUE in 2040

Note: reliability simulations limit market imports to 50 MW during hours 19-22

PNM Talk to us. PNM.com

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519
NPV CO2, MM tons	10.8	11.1	10.8	10.9	10.7
Weighted avg. TRL (firm 2040)	9.00	9.00	8.97	8.96	8.87
Loss of load expectation (2032), days per year with a loss of load	**0.04**	**0.06**	**0.08**	**NA**	**0.09**
Loss of load expectation (2040), days per year with a loss of load	**0.02**	**0.11**	**0.27**	**NA**	**0.05**
Expected unserved energy (2040), MWh per year	20	30	139	NA	15
Single simulation max EUE (2040), MW loss in largest load loss hour	1,342	965	663	NA	663

Max EUE highest in portfolio without dispatchable resources – even with the lowest LOLE (when events occur, though infrequent, they are severe)

Note: reliability simulations limit market imports to 50 MW during hours 19-22

PNM Talk to us. PNM.com

Near-final results

CURRENT TRENDS & POLICY – SCENARIOS ADJUSTED FOR RELIABILITY

	Base technologies	Base technologies less 3,000 MW battery storage
Loss of load expectation (2040), days per year with a loss of load	**0.02**	**0.09**
Expected unserved energy (2040), MWh per year	20	62
Single simulation max EUE (2040), MW loss in largest load loss hour	1,342	1,528
Adjusted PVRR (est.), $000	11,745,931	10,562,508

	Base technologies + LDES	Base technologies + LDES with additional 400 MW battery storage
Loss of load expectation (2040), days per year with a loss of load	**0.27**	**0.10**
Expected unserved energy (2040), MWh per year	139	70
Single simulation max EUE (2040), MW loss in largest load loss hour	663	1,515
Adjusted PVRR (est.), $000	10,130,522	10,288,312

- EnCompass is a least-cost optimization model, not a reliability optimization model
- We give EnCompass reliability inputs to give it guidance regarding the necessary level of capacity and energy for a desired level of reliability
- Because EnCompass is not a reliability model, its not designed to be precise in terms of reliability metrics
- EnCompass results are evaluated using SERVM – this provides a check on the EnCompass reliability approximations
- Portfolios can then be adjusted so that they achieve 0.1 LOLE

Note: reliability simulations limit market imports to 50 MW during hours 19-22; adjustments to PVRR include PV of 3-year Revenue Requirement for new battery capacity

Near-final results

CURRENT TRENDS & POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	11,745,931	9,732,881	10,130,522	9,936,495	9,603,519

	Base technologies less 3,000 MW	Base technologies + CT	Base technologies + all LDES + 400 MW battery storage	Base technologies + all LDES + CT	Base technologies + LDES + NG
Adjusted PVRR (est.), $000	10,562,508	9,732,881	10,288,312	9,936,495	9,603,519

Even with adjustments, the PVRR ranking does not change

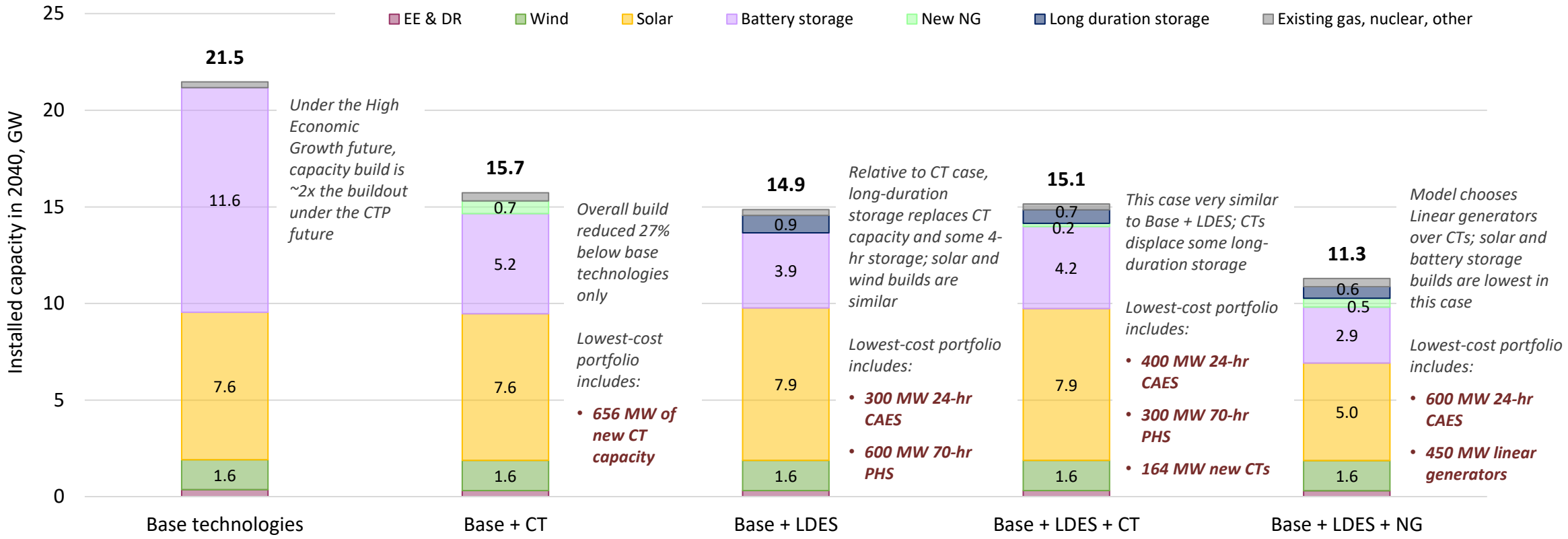
Note: adjustments to PVRR include PV of 3-year Revenue Requirement for new battery capacity

Near-final results

HIGH ECONOMIC GROWTH – 2040 INSTALLED CAPACITY ACROSS SCENARIOS

Fewer options ← → *More options*

The more options EnCompass has, the lower the total build



Under the High Economic Growth future, capacity build is ~2x the buildout under the CTP future

Overall build reduced 27% below base technologies only

Lowest-cost portfolio includes:

- ***656 MW of new CT capacity***

Relative to CT case, long-duration storage replaces CT capacity and some 4-hr storage; solar and wind builds are similar

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***600 MW 70-hr PHS***

This case very similar to Base + LDES; CTs displace some long-duration storage

Lowest-cost portfolio includes:

- ***400 MW 24-hr CAES***
- ***300 MW 70-hr PHS***
- ***164 MW new CTs***

Model chooses Linear generators over CTs; solar and battery storage builds are lowest in this case

Lowest-cost portfolio includes:

- ***600 MW 24-hr CAES***
- ***450 MW linear generators***

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666

Lowest-cost portfolio is the "Kitchen sink" with the largest number of new resource options; PVRRs much higher given significant loads

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666
NPV CO2, MM tons	11.4	12.5	11.3	11.7	11.5

Portfolios without thermal resources achieve lowest NPV CO2; "Kitchen sink" with linear generators achieves lower emissions than Base + LDES + CTs

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666
NPV CO2, MM tons	11.4	12.5	11.3	11.7	11.5
Weighted avg. TRL (firm 2040)	9.00	9.00	8.98	8.97	8.86

TRL lowest for portfolios with greater number of resource options

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666
NPV CO2, MM tons	11.4	12.5	11.3	11.7	11.5
Weighted avg. TRL (firm 2040)	9.00	9.00	8.98	8.97	8.86
Loss of load expectation (2040), days per year with a loss of load	**0.04**	**0.17**	**4.91**	**NA**	**10.15**

2040 LOLE extremely high for Base + LDES and Base + LDES + NG cases

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Talk to us.

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666
NPV CO2, MM tons	11.4	12.5	11.3	11.7	11.5
Weighted avg. TRL (firm 2040)	9.00	9.00	8.98	8.97	8.86
Loss of load expectation (2040), days per year with a loss of load	**0.04**	**0.17**	**4.91**	**NA**	**10.15**
Expected unserved energy (2040), MWh per year	24	129	3,580	NA	3,697

For high LOLE cases, EUE relatively similar

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666
NPV CO2, MM tons	11.4	12.5	11.3	11.7	11.5
Weighted avg. TRL (firm 2040)	9.00	9.00	8.98	8.97	8.86
Loss of load expectation (2040), days per year with a loss of load	**0.04**	**0.17**	**4.91**	**NA**	**10.15**
Expected unserved energy (2040), MWh per year	24	129	3,580	NA	3,697
Single simulation max EUE (2040, MW loss in largest load loss hour	1,519	2,155	1,979	NA	1,950

Max EUE highest under CT case

Note: reliability simulations limit market imports to 50 MW during hours 19-22

Near-final results

HIGH ECONOMIC GROWTH – SCENARIOS ADJUSTED FOR RELIABILITY

	Base technologies + LDES	Base technologies + LDES with additional 1,500 MW battery storage	Base technologies + LDES with additional 2,000 MW battery storage
Loss of load expectation (2040), days per year with a loss of load	**4.91**	**0.14**	**0.06**
Expected unserved energy (2040), MWh per year	3,580	107	33
Single simulation max EUE (2040), MW loss in largest load loss hour	1,979	1,702	1,616
Adjusted PVRR (est.), $000	15,087,068	15,678,780	15,876,017

	Base technologies + LDES + NG	Base technologies + LDES + NG with additional 1,500 MW battery storage
Loss of load expectation (2040), days per year with a loss of load	**10.15**	**0.10**
Expected unserved energy (2040), MWh per year	3,697	51
Single simulation max EUE (2040), MW loss in largest load loss hour	1,950	1,168
Adjusted PVRR (est.), $000	12,993,666	13,585,378

Note: reliability simulations limit market imports to 50 MW during hours 19-22; adjustments to PVRR include PV of 3-year Revenue Requirement for new battery capacity

Near-final results

HIGH ECONOMIC GROWTH

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG
PVRR, $000	18,726,726	14,720,773	15,087,068	14,933,612	12,993,666

	Base technologies	Base technologies + CT	Base technologies + all LDES + 2,000 MW battery storage	Base technologies + all LDES + CT + 1,500 MW battery storage	Base technologies + LDES + NG + 1,500 MW battery storage
Adjusted PVRR (est.), $000	18,726,726	14,720,773	15,876,017	15,525,324	13,585,378

Even with adjustments, the PVRR ranking does not change

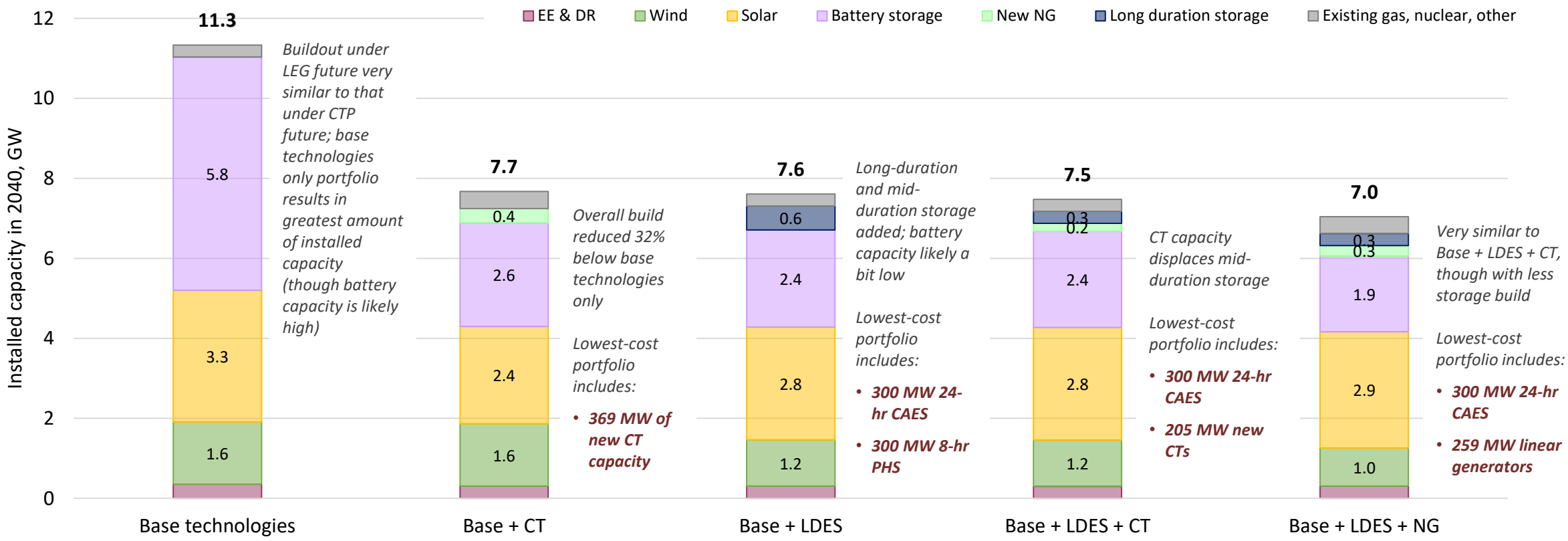
Note: adjustments to PVRR include PV of 3-year Revenue Requirement for new battery capacity

Near-final results

LOW ECONOMIC GROWTH – 2040 INSTALLED CAPACITY ACROSS SCENARIOS

Fewer options ← → *More options*

The more options EnCompass has, the lower the total build



Buildout under LEG future very similar to that under CTP future; base technologies only portfolio results in greatest amount of installed capacity (though battery capacity is likely high)

Overall build reduced 32% below base technologies only

Lowest-cost portfolio includes:

- ***369 MW of new CT capacity***

Long-duration and mid-duration storage added; battery capacity likely a bit low

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***300 MW 8-hr PHS***

CT capacity displaces mid-duration storage

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***205 MW new CTs***

Very similar to Base + LDES + CT, though with less storage build

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***259 MW linear generators***

Near-final results

LOW ECONOMIC GROWTH

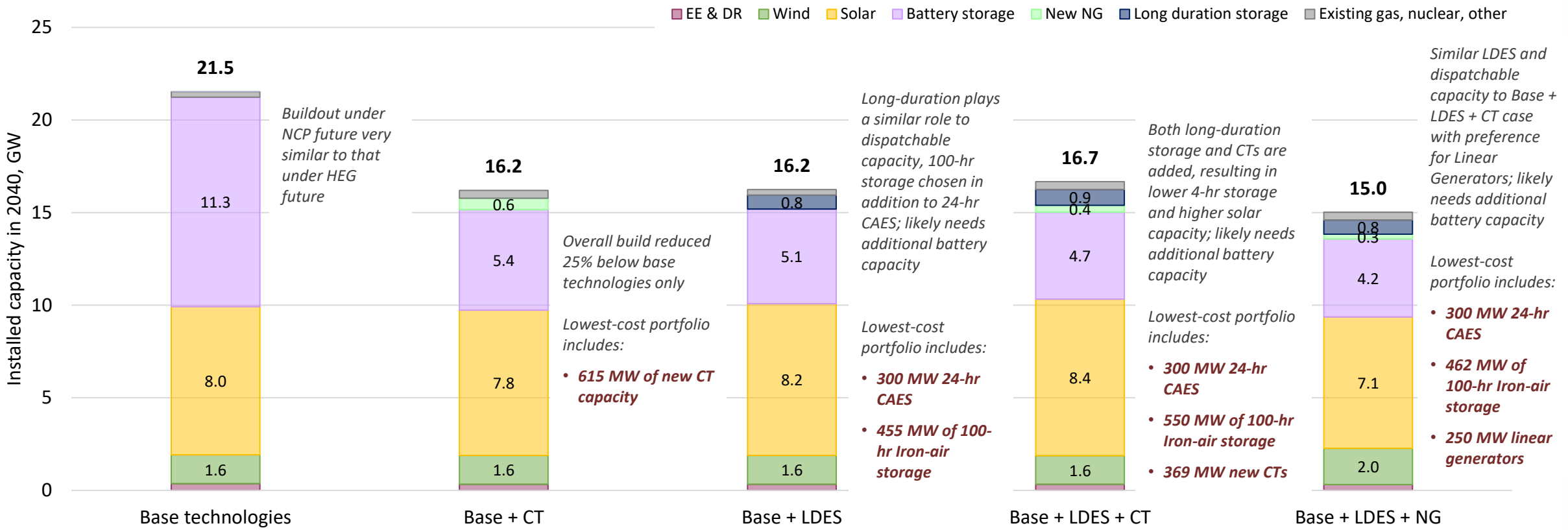
	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG + CCS
PVRR, $000	10,774,465	9,300,964	9,528,040	9,457,300	9,142,507
NPV CO2, MM tons	11.7	11.9	11.7	11.9	10.9
Weighted avg. TRL (firm 2040)	9.00	9.00	8.97	8.97	8.89

Near-final results

NATIONAL CARBON POLICY – 2040 INSTALLED CAPACITY ACROSS SCENARIOS

Fewer options ← → *More options*

The more options EnCompass has, the lower the total build



Buildout under NCP future very similar to that under HEG future

Overall build reduced 25% below base technologies only

Lowest-cost portfolio includes:

- ***615 MW of new CT capacity***

Long-duration plays a similar role to dispatchable capacity, 100-hr storage chosen in addition to 24-hr CAES; likely needs additional battery capacity

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***455 MW of 100-hr Iron-air storage***

Both long-duration storage and CTs are added, resulting in lower 4-hr storage and higher solar capacity; likely needs additional battery capacity

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***550 MW of 100-hr Iron-air storage***
- ***369 MW new CTs***

Similar LDES and dispatchable capacity to Base + LDES + CT case with preference for Linear Generators; likely needs additional battery capacity

Lowest-cost portfolio includes:

- ***300 MW 24-hr CAES***
- ***462 MW of 100-hr Iron-air storage***
- ***250 MW linear generators***

PNM Talk to us. PNM.com

Near-final results

NATIONAL CARBON POLICY

	Base technologies	Base technologies + CT	Base technologies + all LDES	Base technologies + all LDES + CT	Base technologies + LDES + NG + CCS
PVRR, $000	20,810,565	14,800,632	15,865,564	14,747,378	14,196,890
NPV CO2, MM tons	10.9	11.5	10.9	11.2	10.6
Weighted avg. TRL (firm 2040)	9.00	9.00	8.88	8.86	8.83

Near-final results

PNM'S OBSERVATIONS & NEXT STEPS

High-level observations:

- Lowest-cost portfolios include dispatchable technologies and long-duration storage
- Technology combinations provide lower-cost alternatives to single-technology scenarios – generally, the more resource options available to the model, the lower the cost of the resulting portfolio

Technology observations:

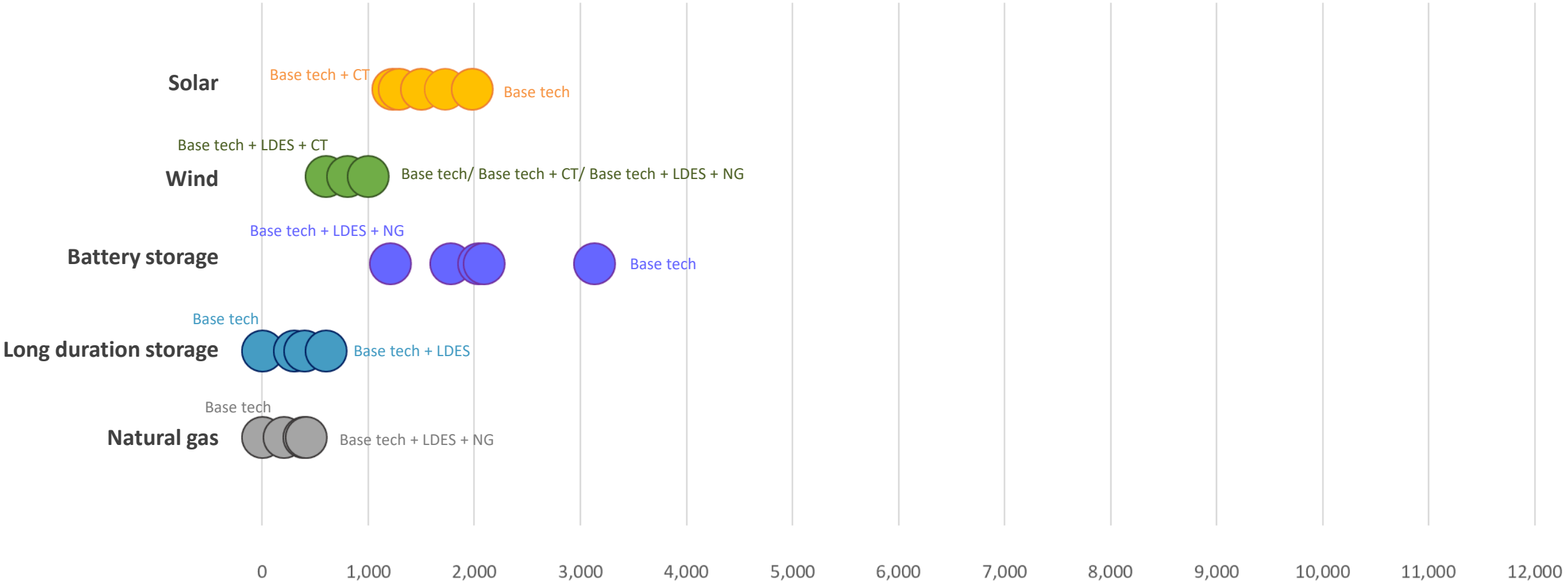
- Wind is included in all portfolios; renewable generation is required to meet energy, RPS, and CO2 requirements
- Portfolios often include storage with at least 24 hours of duration, and >50% efficiency – often combining 24-hour 67% RTE storage with 70-hr 85% RTE
- Linear generators are chosen over CTs when the model is given the option to add both
- When given the choice, model adds a combination of short duration storage, long duration storage, and dispatchable generation – resource diversity will be important for maintaining a reliable carbon-free system
- Cost declines are an important consideration for emerging technologies

Next Steps

- Incorporate reliability adjustments into portfolios based on SERVM results
- Examine robustness of initial observations against other key sensitivities, including implications of technology cost uncertainty upon results that rely heavily on emerging technologies
- Conduct resiliency study on most promising portfolio options
- Compare quantitative and qualitative metrics for Phase 3 portfolios to inform best path forward for Most Cost-Effective Portfolio

Near-final results

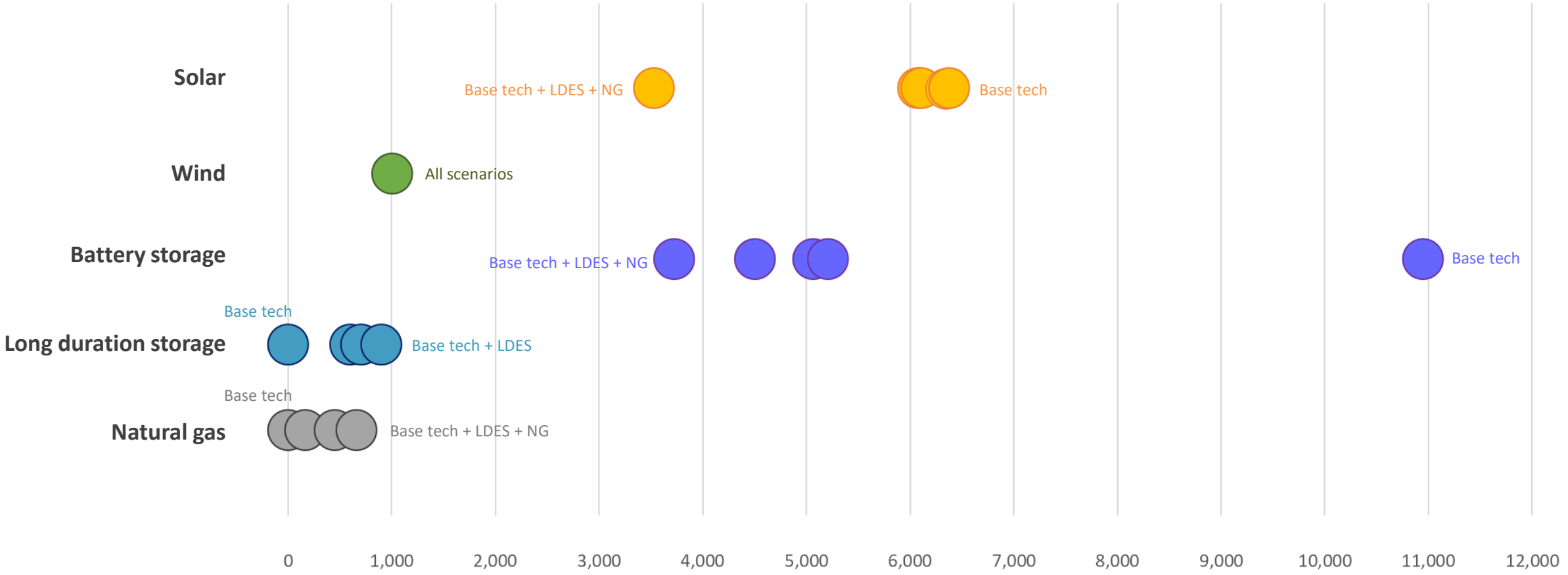
POTENTIAL RANGE OF NEW CAPACITY BY 2040 (CTP CASE)



PNM Talk to us. PNM.com

Near-final results

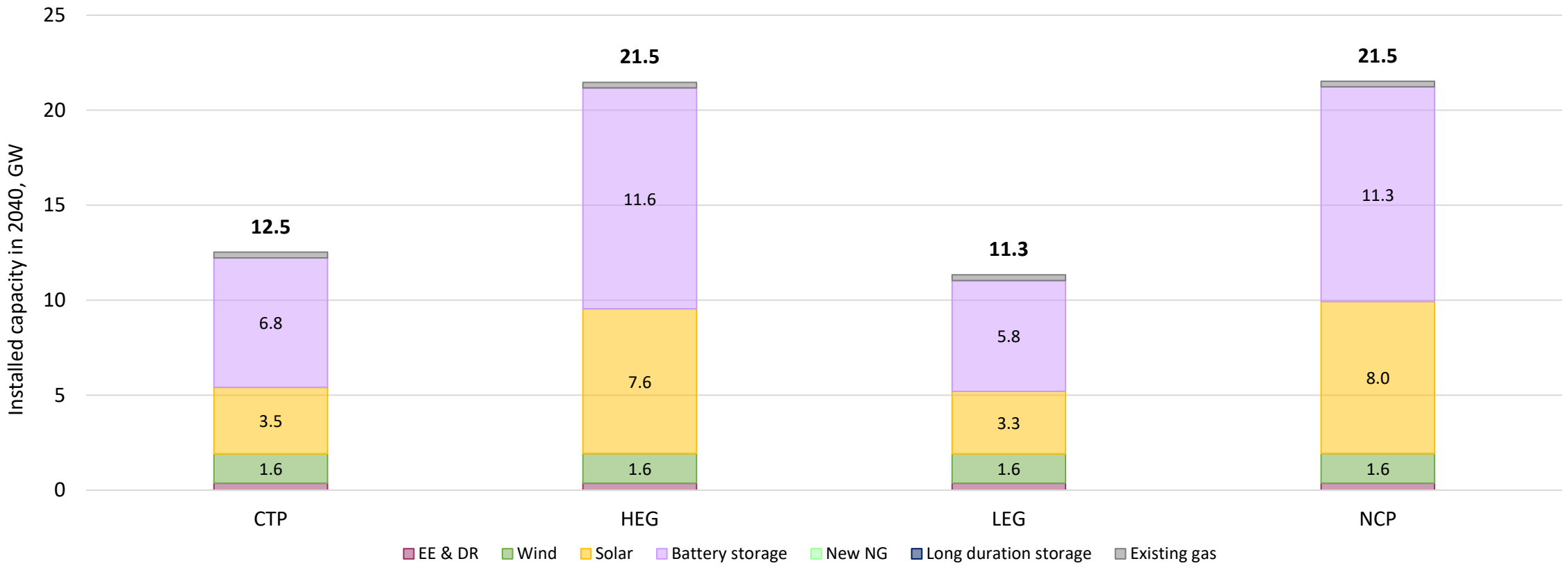
POTENTIAL RANGE OF NEW CAPACITY BY 2040 (HEG CASE)



PNM Talk to us. PNM.com

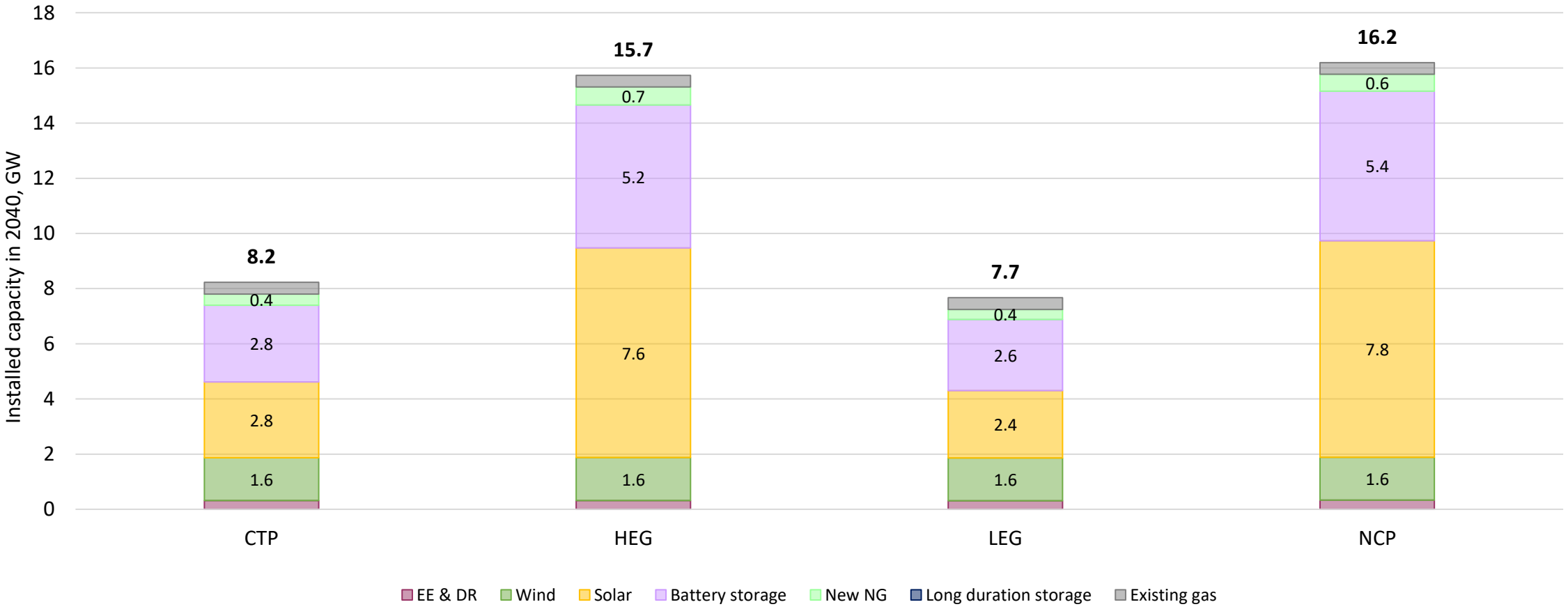
APPENDIX

BASE TECHNOLOGIES ONLY SCENARIO



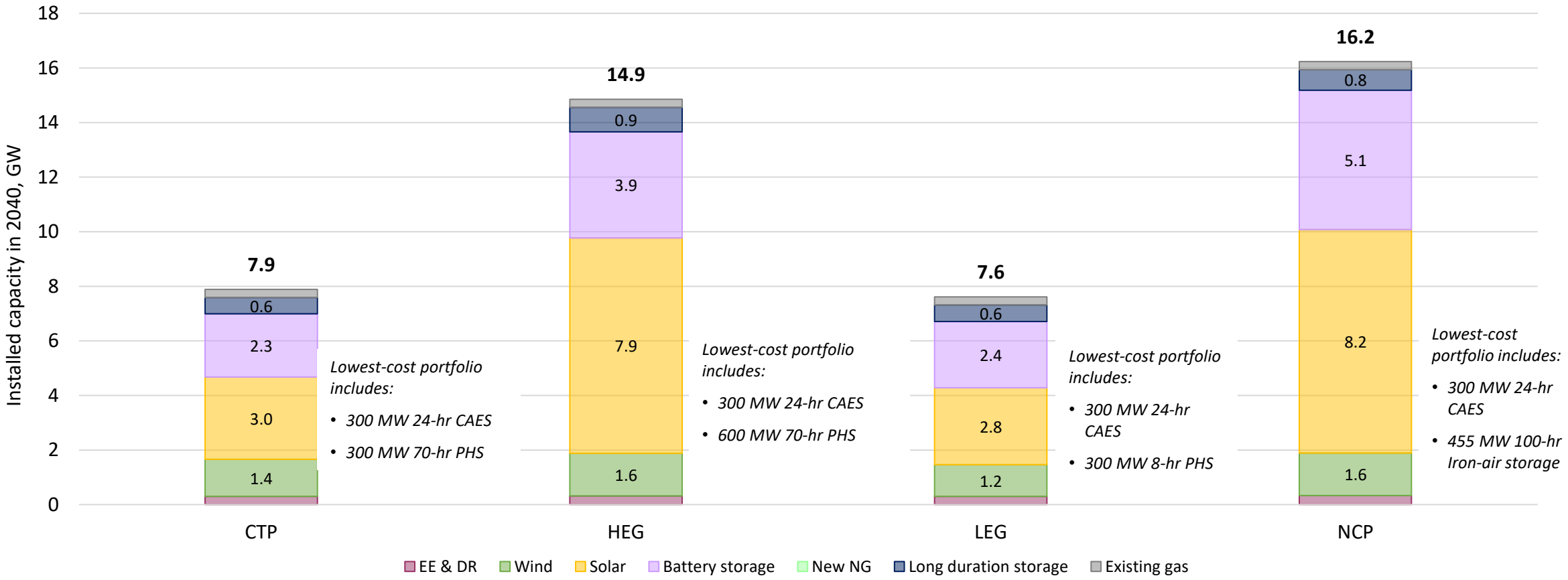
Talk to us.

THERMAL – CT SCENARIO



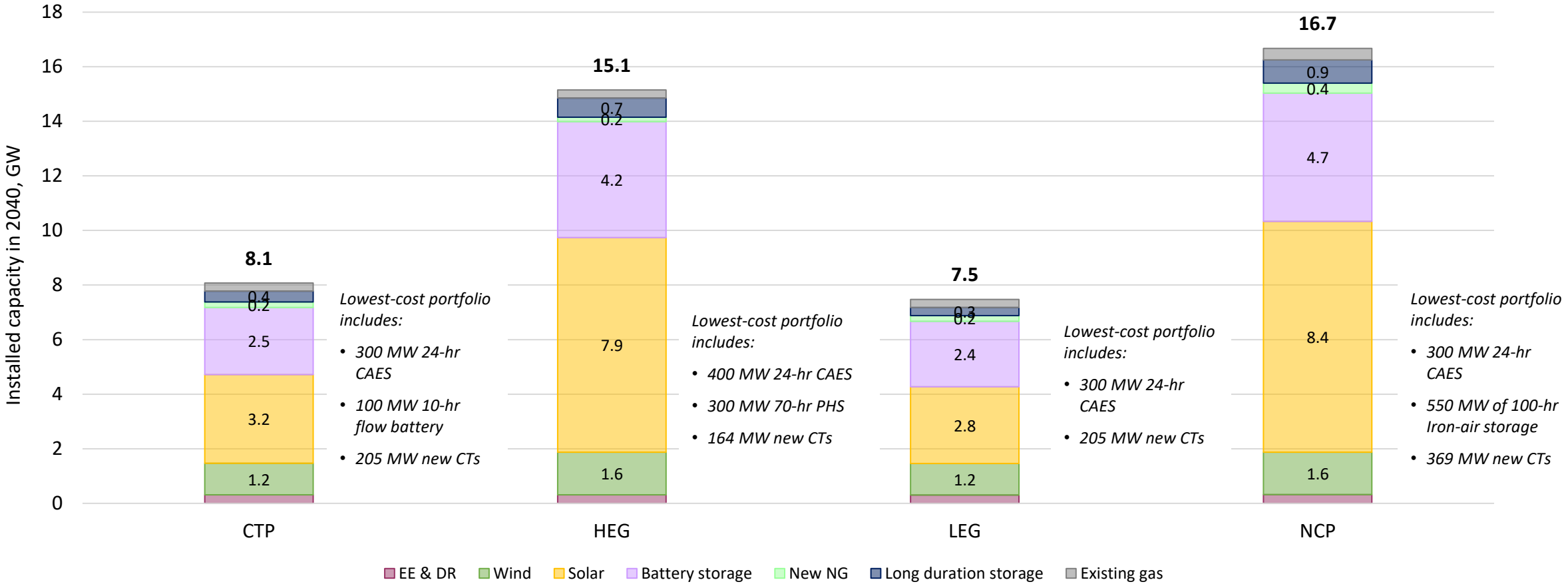
Talk to us.

BASE TECHNOLOGIES + LDES SCENARIO



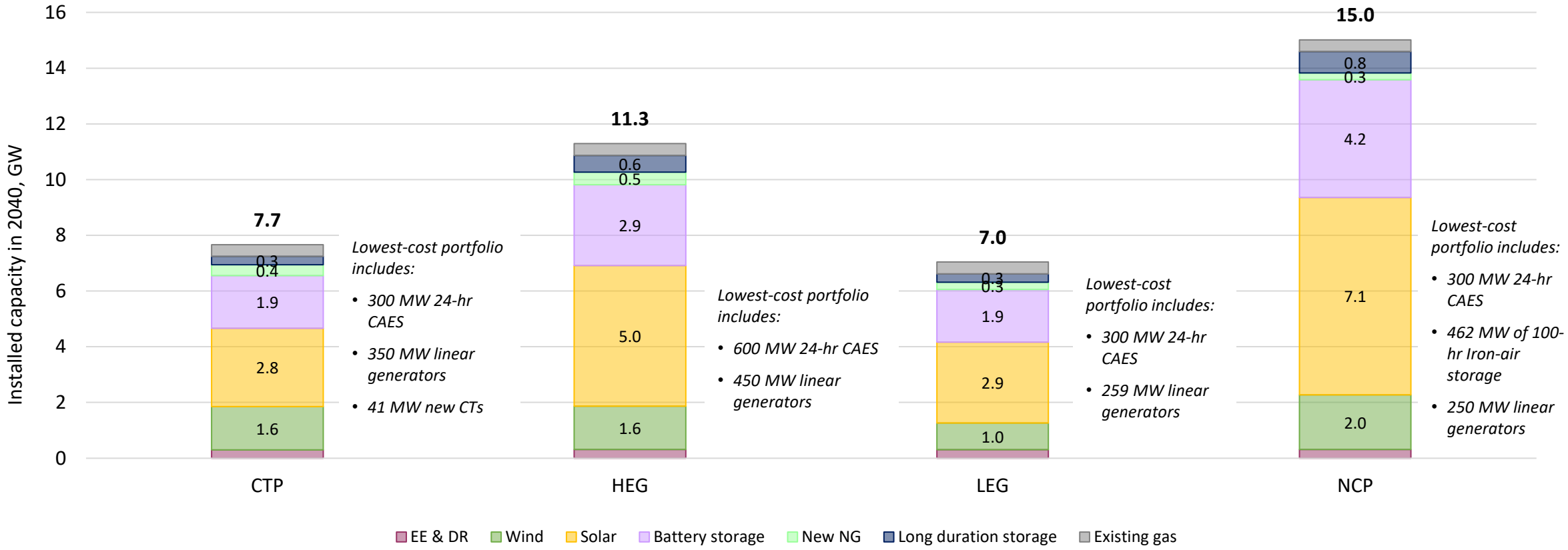
PNM Talk to us. PNM.com

BASE TECHNOLOGIES + LDES + CT SCENARIO



Talk to us.

BASE TECHNOLOGIES + LDES + NG SCENARIO



Talk to us.

2023 IRP CORE FUTURES

Key assumption	Current Trends & Policy	High Economic Growth	Low Economic Growth	National Carbon Policy (Carbon-free by 2035)
Load forecast	Mid	High	Low	High
BTM PV forecast	Mid	High	Low	High
EV adoption forecast	Mid	High	Low	High
Building Electrification Forecast	Mid	Mid	Mid	High
Economic development	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

2023 IRP SENSITIVITIES

Gridworks Compiled Presentations

	Sensitivity	Load forecast	Economic Development	BTM PV forecast	EV adoption forecast	Building electrification	Gas price forecast	CO2 price forecast	Technology costs	IRA tax credits & incentives
Load	High load	**High**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Strong ED growth	Mid	**Stable**	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Very strong ED growth	Mid	**Stable**	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Extreme weather	**P90 hot/cold**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	Low load	**Low**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	TOU pricing	**TOU shaping**	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
BTM	High BTM PV	Mid	Limited ED	**High**	Mid	Mid	Mid	Mid	Mid	Extended
	Low BTM PV	Mid	Limited ED	**Low**	Mid	Mid	Mid	Mid	Mid	Extended
	No BTM PV	Mid	Limited ED	**Zero**	Mid	Mid	Mid	Mid	Mid	Extended
	High EV adoption	Mid	Limited ED	Mid	**High**	Mid	Mid	Mid	Mid	Extended
	Low EV adoption	Mid	Limited ED	Mid	**Low**	Mid	Mid	Mid	Mid	Extended
	High building electrification	Mid	Limited ED	Mid	Mid	**High**	Mid	Mid	Mid	Extended
	DERMS	Mid	Limited ED	**High**	**High**	Mid	Mid	Mid	Mid	Extended
Gas price	High gas price	Mid	Limited ED	Mid	Mid	Mid	**High**	Mid	Mid	Extended
	Low gas price	Mid	Limited ED	Mid	Mid	Mid	**Low**	Mid	Mid	Extended
Carbon price	IRP rule $40 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$40/ton**	Mid	Extended
	IRP rule $20 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$20/ton**	Mid	Extended
	IRP rule $8 CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**$8/ton**	Mid	Extended
	PNM high CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**High**	Mid	Extended
	PNM mid CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	Extended
	PNM low CO2 price	Mid	Limited ED	Mid	Mid	Mid	Mid	**Low**	Mid	Extended
Technology costs	Fast technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	**Low**	Extended
	Slow technology advancement	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	**High**	Extended
	IRA tax credits expire	Mid	Limited ED	Mid	Mid	Mid	Mid	Mid	Mid	**Expire 2032-2034**

TECHNOLOGY READINESS LEVEL DEFINITIONS

TRL 0 – Idea phase
- Unproven Concept with no testing having been done

TRL 1 – Basic Research
- Needs of the technology can be described, but have no evidence

TRL 2 – Technology Formulation
- Concept and application have been formulated

TRL 3 – Needs Validation
- You have an initial "offering", stakeholders are interested

TRL 4 – Small Scale Prototype
- Built in laboratory environment.

TRL 5 – Large Scale Prototype
- Tested in intended environment

TRL 6 – Prototype System
- Tested in intended environment with close to expected performance

TRL 7 – Demonstration System
- Operating in operational environment at pre-commercial scale

TRL 8 – First of Kind Commercial System
- All technical processes and systems to support commercial activity at ready state

TRL 9 – Full Commercial Application
- Technology on "general availability" for all consumers

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



Integrated Resource Plan:
Statement of Need Table of Contents
Working group suggestions for Public Service New Mexico - August 21, 2023

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction

The Statement of Need [Son] is a new PRC-required section in PNM's 2023 IRP filing. The SoN provides the inputs of a self-selected group of ~250 external persons [give us a name e.g. IRP External Advisor Group [EAG]]from the public, governmental agencies, and parties with interest in the long term planning by PNM, [a wholly owned, regulated power-generating subsidiary of the holding company PNMR that provides approximately 2,000 MW of electrical power to more than 525,000 residential and business customers in central and northern New Mexico.

The EAG has reviewed the results/recommendations of the 2023 modeling process. This SoN 2023 includes:

a) Examination of identified generation and storage resources to maintain PNM as the reliable [24/7/365] provider of low-carbon power at the least cost to its rate paying customers. See Comprehensive Table of Resources;

b) Response to PNM's preferred 2023 plan/portfolio;

c) Additional resources not included in the 2023 modeling;

d) Other considerations related to the transition from fossil fuels in PNM's power generation portfolio in the short term planning period until 2026 and the IRP twenty year planning horizon until 2043;

e) Items for Future Discussion, beyond this IRP, that the EAG identified for monitoring and possible inclusion in future PNM IRPs.

2. **Vision and Goals**
    a. The identification of a set of resources and a sequencing of those resource deployments that conforms to the regulations and policies of the State of New Mexico, reliably serves all customers at a reasonable cost with electrical energy that is that is resilient in the face of national security, technology, infrastructure, resource, cyber and environmental constraints.
    b. Goals
        i. Support Rapid Decarbonization & Electrification
        ii. Reliability and Resilience: Utility's Obligation to Serve
            1. Minimum Reserve Requirements
            2. Reliability Standards
            3. Swift recovery from climate or security threats
        iii. Public Interest and Equity
            1. Responsibilities to Ratepayers and Stakeholders
                a. Affordability
                b. Availability to Underserved Communities
                c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
                d. Impacts on Workforce (e.g., transition of workers from closing coal plants, exposure to weather, etc.)
            2. Costs associated with the development and deployment of all candidate resources
                a. Costs of Energy to Consumers
                b. Life Cycle Impacts
                    i. Pollution
                    ii. Greenhouse Gas emission
                    iii. Materials
                    iv. Utility disposal
            3. Improve Communication to the General Public
                a. PNM communications with public re: change in timing on demand, how that changes system needs, and smart meter data collection and security
                b. Not In My BackYard (NIMBY) attitude regarding siting polluting resources should be reversed and clean, job and tax base creating resources, should be sited in frontline communities as well.
3. **Identified Decision Points and Pathways**
    a. "Getting to Zero" Greenhouse Gas
        i. Motivations
            1. Regulations & Policy
                a. Energy Transition Act (2019)
                b. EPA's proposed greenhouse gas emissions standards for power plants
                c. N.M. methane control rules
            2. Public service in response to March 2023 IPCC report analysis summary for policymakers
            3. Recognition of Company's corporate commitment to zero carbon by 2040
    b. Making "no regrets" Decisions
        i. Evaluation of land use and community impact

ii. Broad Inclusion of Stakeholders
iii. Minimizing investment risk
    1. Avoiding and minimizing stranded assets
        a. Loss of public trust
iv. Maximizing Infrastructure Investment Opportunity
    1. First to market w/ long term solutions
    2. Public trust and sentiment
v. Value of money vs future human life opportunities

c. Evaluate & Pursue Regional Planning and Coordination
    i. Organized market opportunities
    ii. Future regional transmission operator (RTO) opportunities
d. Modernizing the Grid
    i. Policy needs to support reaching carbon targets, DSM (demand side management), DG (distributed generation) and other behind-the-meter resources)
    ii. Demonstrate transition from old to new grid structure
    iii. Assessment of impact of all areas of behind-the-meter resources.

4. Resources

a. Resource Description:
    i. A *brief* description of the resource; its technical characteristics.
b. Commercial Maturity:
    i. The Technology Readiness Level (TRL) or similar metric to describe the commercial maturity of the resource. How long has it been used in electric utility applications? This criteria needs to be done carefully. Some technologies have been the brunt of sabotage, business ineptness, and smear campaigns by the opponents.
c. Staged Cost:
    i. This is a breakdown of cost by scale (if applicable). For example, solar may have a cost for 1 MW to 5 MW; and a different cost for 10 MW to 100 MW. And for storage it should also include Return Trip Efficiency (TRE) and similar variables as are in the below table.
d. Grid Applications and Benefits:
    i. Why is this resource important to the grid? What are its applications and benefits?
e. Status of each resource in the modeling process (i.e., included, not included with reason why, not available for inclusion for lack of data, etc.)
f. Candidate Resources
    i. Base technologies
        1. Wind
        2. Solar
        3. 4-hr li-ion storage
        4. Energy efficiency
        5. Demand response
    ii. Other Resources
        1. Pumped hydro storage 70-hr (NW NM)
        2. Pumped hydro storage 8-hr (NW NM)
        3. Iron-air storage
        4. Compressed Air Energy Storage
        5. Liquified Air Energy Storage

6. Flow battery
7. Thermal storage (with steam turbine)
8. Combustion Turbines
9. Linear generators
10. Carbon capture retrofit (Afton)
11. NET power plant
12. Hydrogen

5. **Potential New Resources**
    a. Adoption of new technologies
    b. High Penetration of Distributed/Customer-owned Generation
    c. Energy efficiency and demand-response
    d. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
    e. Describe long duration storage options not considered (reference chart 1 in “Items for Discussion” below)
6. **[System Needs]**
7. **Preferred Portfolio - Refer to appendix of resource evaluation**
    a. [results of PNM modeling]
    b. Potential pilot projects
    c. [PNM conclusions]

Items for Future Discussion

"Parking Lot"

1. General
    a. Explanation of the Integrated Resource Plan (IRP)
        i. IRP as a tool for utility's capital outlay plan
        ii. Misconceptions about the 20-year IRP window
        iii. Importance of the 3-year Action Plan
2. Existing resources and technologies
    a. End-of-life considerations
        i. Definition and examples
        ii. Resource disposal post operational life
    b. Energy Resources to consider
        i. Geothermal energy
        ii. Small Modular Reactors (SMRs)
        iii. Issues and concerns with SMRs
    c. Issues with new gas as a resource
    d. Role of Energy Efficiency in IRP
        i. PNM's current portfolio
        ii. The role of IRP
        iii. Energy efficiency measures
    e. Role of Demand Response
    f. Role of Load Management
        i. Time of use rates and dynamic rate options
        ii. Importance of different load shifting scenarios
    g. Consideration for grid improvements for Demand-Side Management (DSM)
3. PNM's programs and their impact on DSM
    a. Whole House Electric Vehicle (WHEV) rate
    b. Implications for low-income customers with smart meters
    c. Electromagnetic wave generation concerns
4. Options for the transition from carbon-based energy
    a. Inclusion of all possible resources
    b. Prioritization based on feasibility, required infrastructure, reliability, and lifecycle costs - Comment by Robert Barber
5. Comments and Concerns from stakeholders
    a. NIMBY and consumer education
    b. Impact of electrification on load forecast
    c. Incorporating wind turbine capabilities into modeling
    d. Need for more information on distribution system planning
    e. Improved data collection on outages, especially in disadvantaged areas
6. Identified Decision Points and Pathways

a. Any impact from Methane?

OUTLINE EDITS

1. 2b3: Swift recovery from climate or security threats
2. Public service in response to March 2023 IPCC report analysis https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23
3. Modernizing the Grid
4. 3e: Assessment of impact of all areas of behind-the-meter resources

1 There are numerous technologies within Long Duration Storage

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDED

Less Desirable → More Desirable

△ Faces geologic constraints[1] | Not enough public datapoints to obtain a reliable value | 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[1], %	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 CO2[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[4]	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[4]	XX	>100	55–75	4-9

1 Demand potential / market size is limited by the requirement for specific geological formations
2 Codified based on primary technology type
3 Can function as inter-day, but organized based on longest duration potential
4 Some flow batteries under development will not work for multi-day, but it is categorized here as such given the technology's maximum duration

U.S. DEPARTMENT OF ENERGY 4

Source: Adapted from LDES Council Net Zero Power Report 2021, Wood Mackenzie Long Duration Energy Storage Report 2022, Company websites, Academic research

Welcome!

Stakeholder Engagement Meeting
(Meeting #9)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, Sept. 28

9:00 AM – 11:00 AM Mountain Daylight Time

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Materials available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose and Outcomes of Today's Meeting

Receive an update on modeling results, review Statement of Need (SoN), and discuss Action Plan suggestions.

KEY OUTCOMES

- Comparison of Statement of Need components
- Identification of areas of agreement and disagreement
- Discussion and mapping of candidate Action Plan items

Agenda

9:00 AM – Welcome, Purpose, Outcomes for the Meeting

9:10 AM – Modeling Update and SoN Implications (PNM team presents)

9:40 AM – SoN Discussion and Agreements

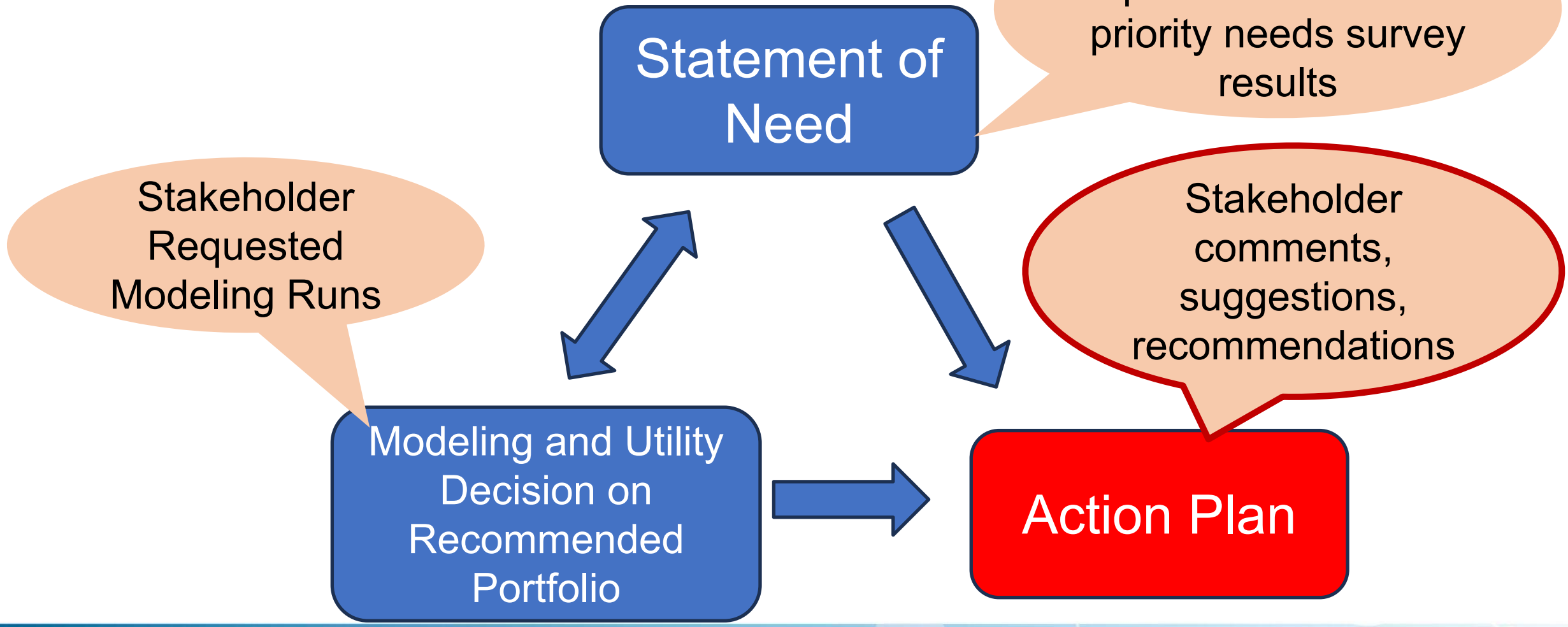
10:10 AM – Break

10:20 AM – Candidate Action Plan Ideas and Mapping

10:50 AM – Summary of Actions and Next Steps, Meeting Feedback

11:00 AM – Adjourn

Summary of Stakeholder Input Activities



Modeling Update and SoN Implications

PNM TEAM

GRIDWORKS

SoN Elements - PNM IRP Placement

PNM SoN and 2023 IRP Mapping, 9/14/23

Gridworks Compiled Presentations

https://gridworks.org/wp-content/uploads/2023/09/2023-09-06-PNM-SoN-and-2023-IRP-Mapping_SENT-20230914-3.xlsx

Stakeholder SoN Section	Stakeholder SoN Point	According to IRP rule 17.7.3.10, is this a required element of the Statement of Need or Elsewhere in the IRP?	If elsewhere, where will it be address in the PNM IRP?	Note
Section Number		Yes / No	Chapter Number	
2. Vision and Goal	The identification of a set of resources and a sequencing of those resource deployments […]	Elsewhere	1.2	
a. The identification of a set of resources and a sequencing of those resource deployments […]		Elsewhere	1.2	
b. Goals		Elsewhere	1.2	
i. Support Rapid Decarbonization & Electrification		Elsewhere	1.2	
ii. Reliability and Resilience: Utility's Obligation to Serve	1.Minimum Reserve Requirements 2.Reliability Standards 3.Swift recovery from climate or security threats	Statement of Need and Elsewhere	1.2	Reliability is the core component of the SoN. Resiliency is addressed in 1.2 and in the
iii. Public Interest and Equity	1. Responsibilities to Ratepayers and Stakeholders	Elsewhere	1.2 2.1 3.3	Affordability, Considerations for Low-income communities, and workforce impacts are address throughout the IRP. Climate justice for individuals and
iii. Public Interest and Equity	2. Costs associated with the development and deployment of all candidate resources	Elsewhere	1.2	Cost of energy is the primary planning objective of the IRP, while lifecycle costs and specific

POTENTIAL RANGE OF CUMULATIVE NEW CAPACITY BY 2028 (CTP CASE)



Most resource needs in the near term have been satisfied with solar and storage procured through recent all-source RFP solicitations; range of uncertainty is relatively narrow.

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

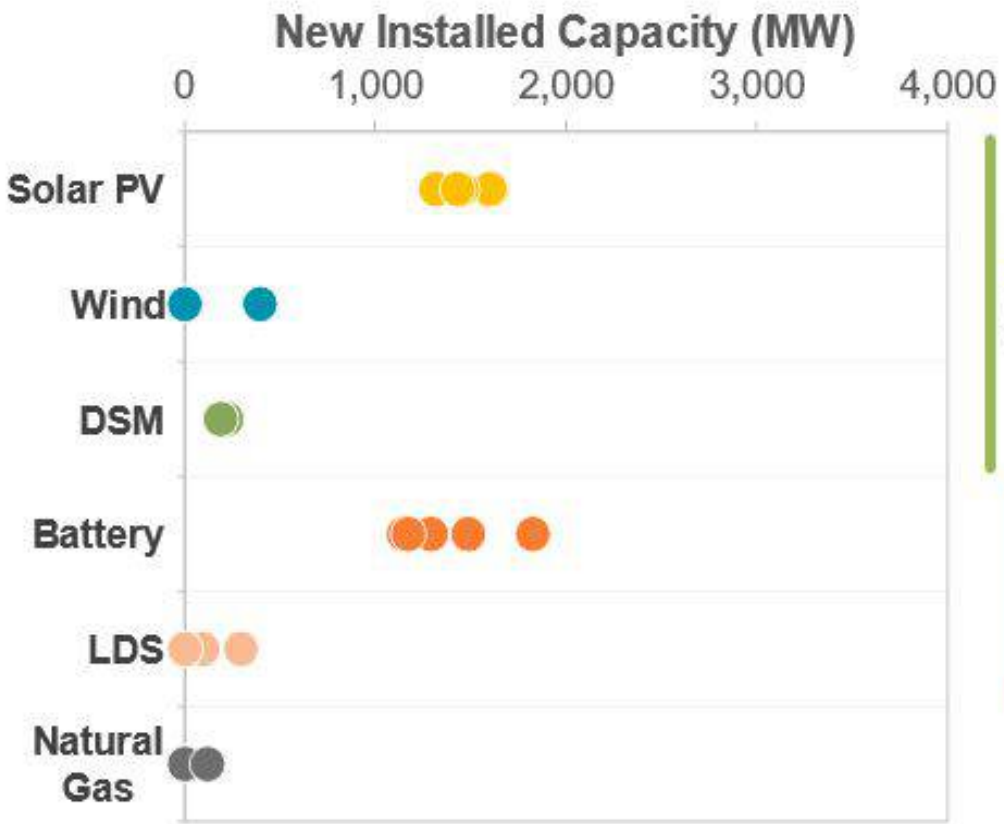
Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

POTENTIAL RANGE OF CUMULATIVE NEW CAPACITY BY 2032 (CTP CASE)



In the medium term, value of resource diversity becomes apparent, as resource selections include capacity from all technology segments

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

POTENTIAL RANGE OF CUMULATIVE NEW CAPACITY BY 2040 (CTP CASE)



In the long term, significant capacity additions are needed to meet carbon-free goals and ensure reliability; scenarios continue to show a wide range of outcomes

Low-cost carbon-free energy resources

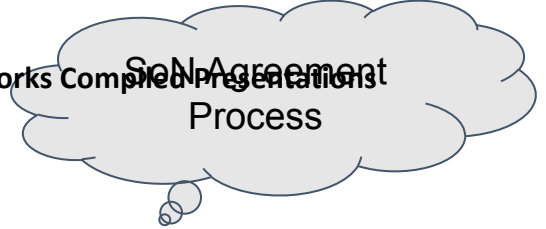
with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output



Do Stakeholders Agree with the PNM Resource Need Analysis?

Are the projected quantities and types of new capacity needs appropriate for the timeframes (thru 2028, 2028-2032, 2033-2040)

SEE PNM SLIDES WITH DETAILS

- Do you believe the projected capacity additions are reasonable?
- Do you believe the projected types of resources are reasonable?

- If you have concerns or do not agree with the capacities and types of resources needed, we must hear from you through one of three options:
  - today, verbally or by chat;
  - by 12 NOON on Oct. 5 via email to info@gridworks.org; or
  - in person at a WebEx meeting from 9:00 -10:00 AM on Oct. 6.

Next Steps in Consideration of Stakeholder Input to the SoN

Gridworks - Summary of key comments from stakeholders.

PNM - Please share your next steps in consideration of the stakeholder input to the SoN.

Definition of the Action Plan

Per the IRP Rule, 17.7.3.11 utility's action plan shall:

1) detail the specific actions the utility shall take to implement the IRP spanning a three-year period following the filing of the utility's IRP;
2) detail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission; and
3) include a status report of the specific actions contained in the previous action plan

The utility creates the action plan, stakeholder input is to be considered.

Process for Discussion of Action Plan Items

- PNM presentation regarding action plan suggestions
- Review of stakeholder input to action plan
- Discussion of items common to stakeholders and PNM
- Process and schedule for submitting stakeholder comments

ACTION PLAN

PNM TEAM

GRIDWORKS

Stakeholder Action Plan Suggestions Offered to Date

Actions need to be measurable and able to be checked for compliance. Language is welcome in this regard.

Ideas offered by stakeholders during the June 29 Meeting:

- Changing fossil fuel plants to long duration energy storage as environmental justice for impacted communities
- Collect distribution feeder level reliability metrics to understand reliability equity
- Initiate public information effort regarding electricity sector changes and IRP process

Items introduced during stakeholder modeling run request process:

- Explore availability of landfill gas as supplementary/replacement fuel
- Include extreme weather considerations during next IRP cycle
- Explore benefits from participation in organized regional market, and from participation under extreme weather scenarios
- Incorporate consideration of correlated gas outages in next IRP cycle

Stakeholder Action Plan Suggestions Offered to Date (continued)

Ideas submitted since Aug. 31:

- By 2026, PNM shall have a default time of day rate for all customer classes. PNM shall assess the success of the time of day pilot and develop a plan to enroll all customers on a time-varying rate.
- Achieve demand response impacts of 5% of peak demand by 2026. PNM currently achieves demand response reduction of approximately 3% of peak demand. To reach this goal, PNM should solicit new DR programs with flexible requirements. This new solicitation should go out by mid-2024.
- Develop a list of advanced geothermal developers and ensure they are contacted for future RFI's. Develop a relationship with the advanced geothermal development community in the state
- Work to solicit geothermal bids and bids for a variety of thermal storage technologies.

Stakeholder Action Plan Suggestions Offered to Date (continued)

- Pumped Storage Hydro, CAES and long duration batteries are not currently realistic options. The following technologies are those that seem to be realistically available to PNM: Wind, PV, Li-ion (up to 4 hours economical); CT's; 8 hour pumped hydro. Converge on desired resource characteristics through the IRP process (rather than an IRP that includes potentially non-viable and speculative technologies), and then put out another RFI for narrowing to alternatives that are viable for inclusion in a future RFP and/or bilateral procurement where warranted.
- Hold a 2026 RFP for resources that will come online 2029 and beyond.
- Actively engage with evaluation activity for the most promising, maturing carbon free technologies like thermal or iron-oxide storage
- Share transmission assumptions with stakeholders and allow developers to give feedback and least-cost site projects.
- Prioritize projects and resources that can locate in federally designated energy communities (supported by the Inflation Reduction Act) and deliver low-cost clean energy to while providing economic development in communities that are transitioning from a carbon-based economy.

Stakeholder Action Plan Suggestions Offered to Date (continued)

Ideas regarding the next IRP:

- Upgrade models and software so PNM can model 8760 hours during the capacity expansion phase. Due to software limitations, storage is not modeled holistically in PNM's IRP process
- Refine modeling parameters including forced outage rates and chemical degradation over time for BESS resources
- Include future PPA procurement in the modeling process in addition to the assumption that PNM will own new resources
- Improve financial modeling so it accurately represents the cost difference between a 60-year lifetime resource and a 20-year lifetime resource
- Incorporate consideration of correlated gas outages
- Include extreme weather considerations
- Use a better transmission model. The current "ball and spoke" model is insufficient to the need for planning in the state
- Establish a stakeholder modeling workshop (or series of workshops) that will kickoff no later than 9/15/2024 to inform modeling assumptions and protocols that will be utilized in the 2026 IRP.
- Transition Resource Adequacy modeling to incorporate WRAP forward showing planning requirements and resource attributes no later than PNM's 2026 IRP.

Proposed Framework for Action Plan Items



Final Steps in the Facilitated Stakeholder Process

If you have concerns or do not agree with the capacities and types of resources needed, or any of the proposed action plan items, we must hear from you through one of three options:

- today, by chat;
- by 12 NOON on Oct. 5 via email to info@gridworks.org; or
- in person at a WebEx meeting from 9:00 -10:00 AM on Oct. 6.

- **Oct. 6, 9 - 10:00 AM - optional meeting to submit concerns and comments on SoN and Action Plan**
- **Oct. 19, 9 – 10:30 AM – Update on SoN and Action Plan by PNM**
- Dec. 15 - IRP is filed by PNM
- Dec. 19, 9 - 10:30 AM - Final stakeholder meeting to collect input regarding how you experienced the process
- Gridworks' report to the NM PRC is due Jan. 31, 2024. It will include results of both NM IRP Facilitated Stakeholder Processes (PNM and SPS).

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

PNM 2023-2042 IRP: Modeling Results Update

FACILITATED STAKEHOLDER MEETING

SEPTEMBER 28, 2023



DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

DISCLAIMER - RESULTS ARE PRELIMINARY DRAFT

- PNM has incorporated numerous updates to its modeling in this IRP cycle
- While we have taken every effort to ensure the validity of these techniques, please understand that the results we will discuss are considered preliminary draft results and will likely change as we continue to refine the analysis
- In previous IRP cycles we would not present results before a full draft of the IRP was ready; we have made efforts to get stakeholders involved earlier in this IRP cycle, starting the public advisory process earlier than ever
- In order to maximize stakeholder involvement, presenting preliminary results and inviting feedback earlier is equally important
- At this stage, we will highlight some of the key trends we see so far, and some of the areas that require further study and refinement

STAKEHOLDER MODELING RUN REQUESTS: MODELING RESULTS

STAKEHOLDER MODELING REQUESTS (ENCOMPASS) – SUMMARY OF SCENARIOS (1 OF 2)

1 - Carbon Free 2030

- Accelerate PNM's goal of CO2 free by 2040 to begin by 2030 using National Carbon Policy Future (CTP)
- No new H2 fired resources, CO2 capture technology or new nuclear
- Allow new Base Technologies, Long-Duration Storage technologies and Early Wind expansion as candidate resources

2 - Carbon Free 2030

- Same as Carbon Free 2030 scenario, except system requirement of CO2 free beginning 2035

3 - FCPP Exit 2027 + Valencia Extension to 2039

- PNM to exit share of FCPP by end of 2027 (200 MW) using Current Trends and Policies Future (CTP)
- Valencia PPA extension though end of 2039 (at $0 fixed costs)

4 - FCPP Exit 2027 + Valencia & Reeves Extensions to 2039

- Same as FCPP 1 Scenario with Reeves 1, 2 & 3 (146 MW) extension of operations through end of 2039 (at $0 fixed costs)

STAKEHOLDER MODELING REQUESTS (ENCOMPASS) – SUMMARY OF SCENARIOS (2 OF 2)

5 - High EV + High Building Electrification

- Combine impacts of High Electric Vehicle and High Building Electrification load forecasts in addition to the Current Trends and Policies Future (CTP)
- Allow Base Technologies and Long-Duration Storage technologies as candidate resources

6 - Base Technologies + CT + New DR

- Assume incremental new Demand Response (DR) programs using the Current Trends and Policies Future (CTP)
- Incremental DR requested and modeled at $0 fixed cost
    - 50 MW by 2026, 100 MW by 2028 and 200 MW by 2030
    - New programs callable in all months/all hours, once/day and a maximum of 100 hours per year
- Assume existing programs are extended (Power Saver and Peak Saver) not expanded
- Allow Base Technologies and new CT's as candidate resources

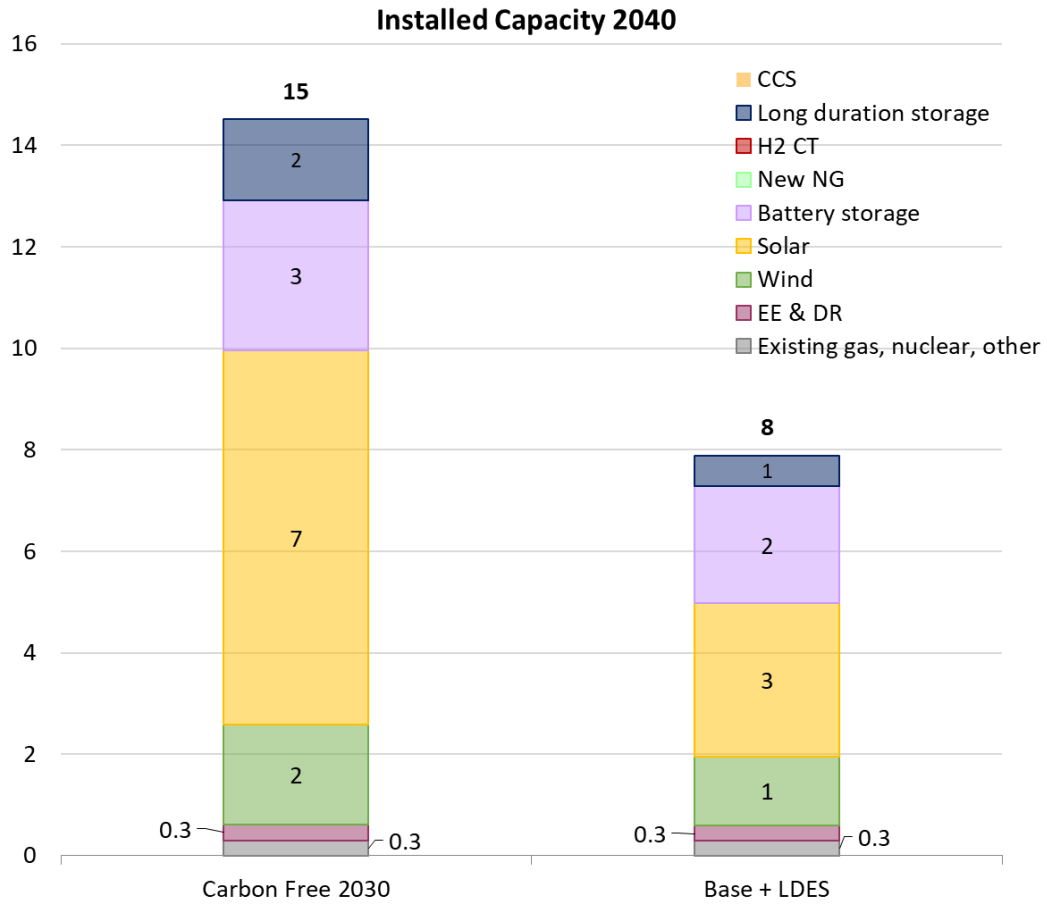
PNM Talk to us. PNM.com

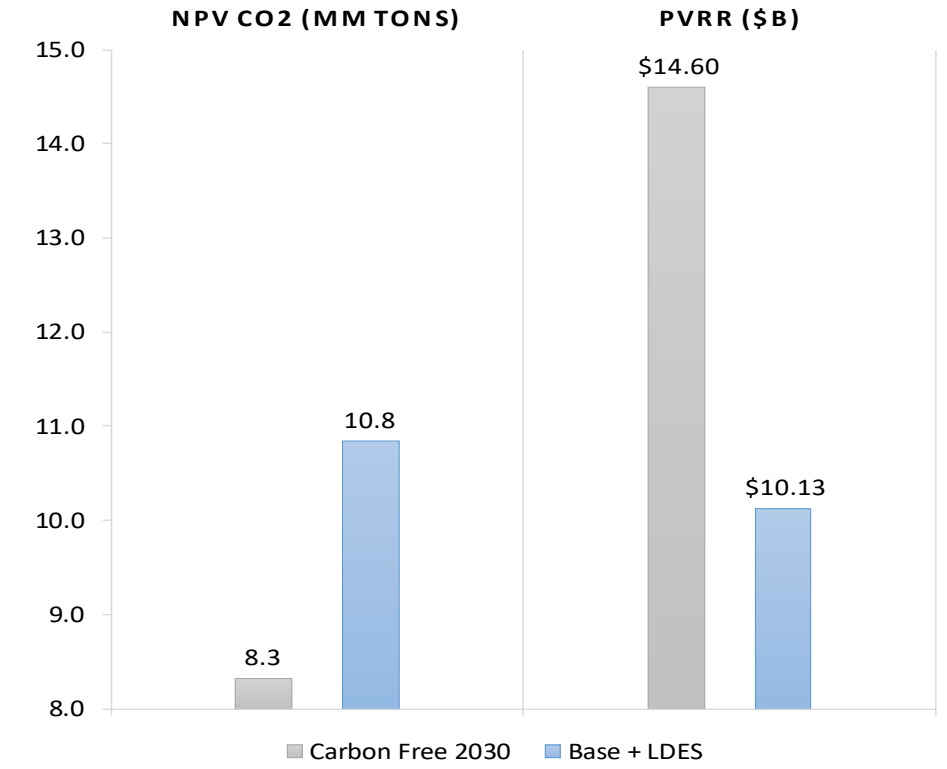
OLD SLIDE – NICK P PRESENTED UPDATED SLIDE

Gridworks Compiled Presentations

PRELIMINARY DRAFT

STAKEHOLDER-REQUESTED SCENARIOS: CARBON FREE 2030





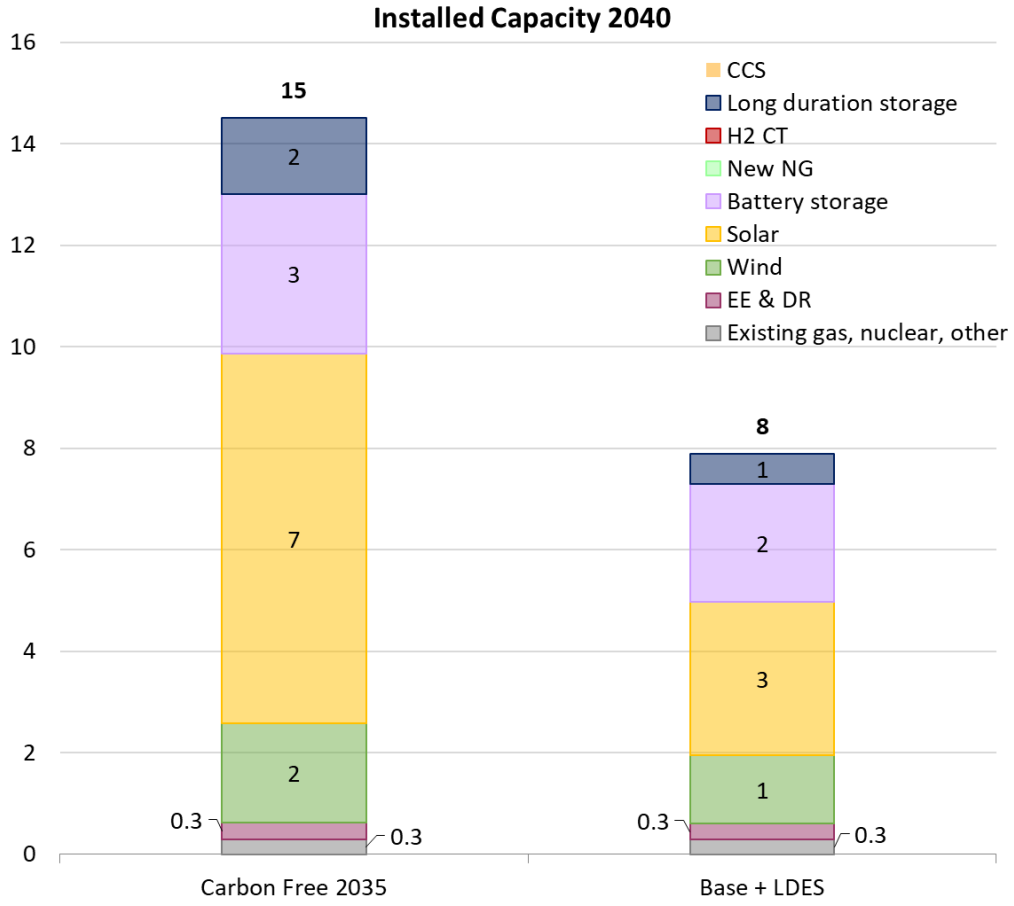
PNM will pay >$1,500/ton to be carbon free by 2030

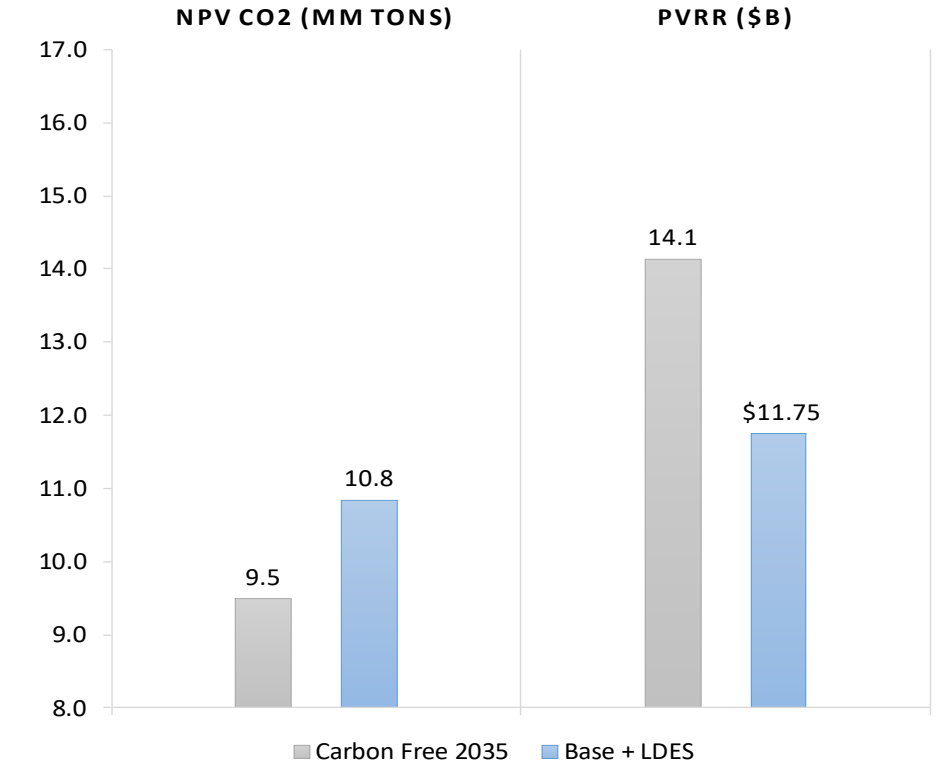
OLD SLIDE – NICK P PRESENTED UPDATED SLIDE

Gridworks Compiled Presentations

PRELIMINARY DRAFT

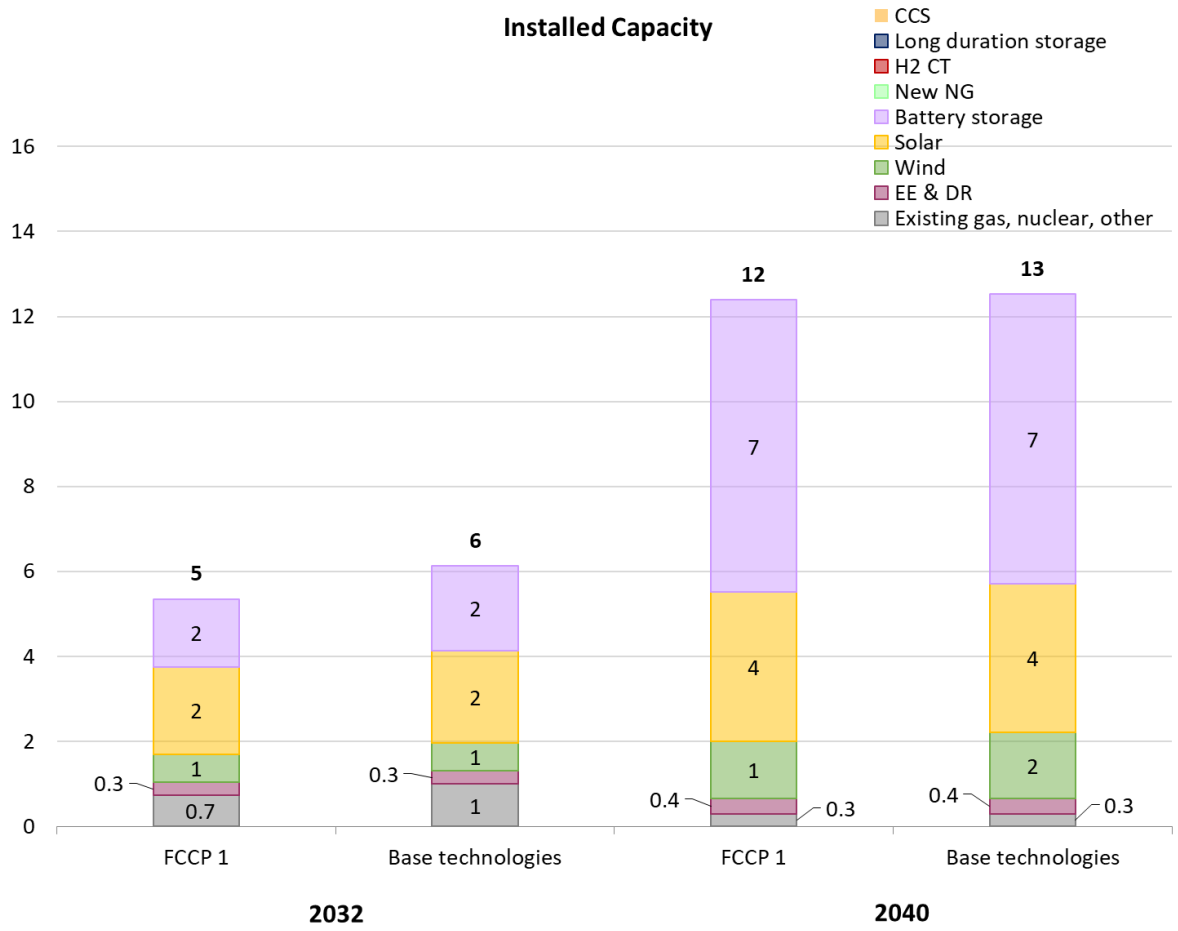
STAKEHOLDER-REQUESTED SCENARIOS: CARBON FREE 2035

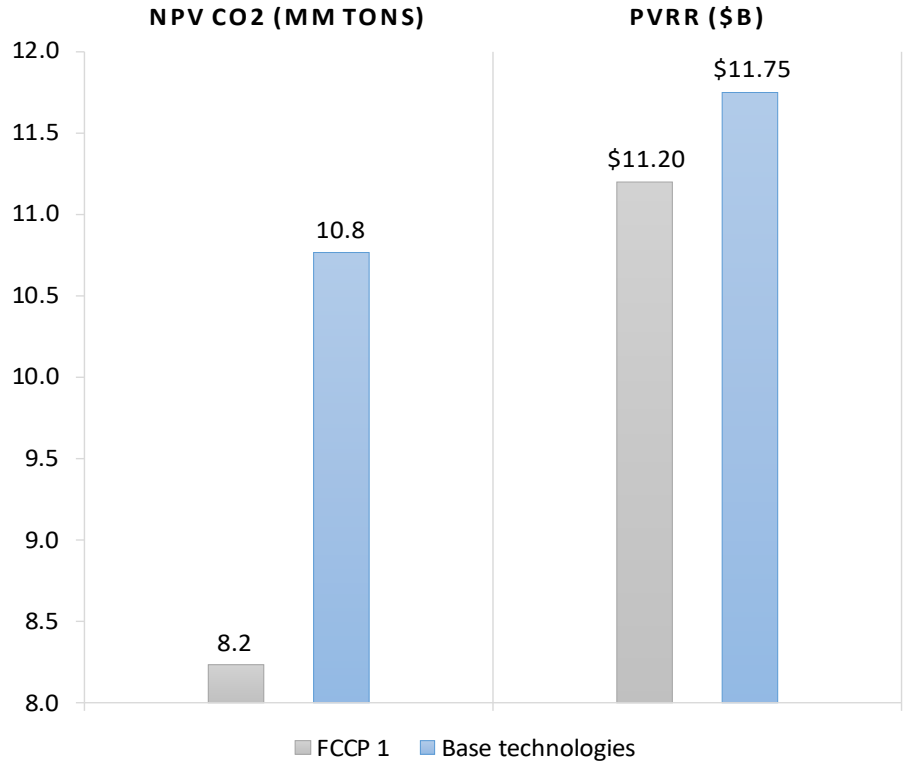




PNM will pay >$1,500/ton to be carbon free by 2035

STAKEHOLDER-REQUESTED SCENARIOS: FCPP EXIT 2027 + VALENCIA EXT TO 2039

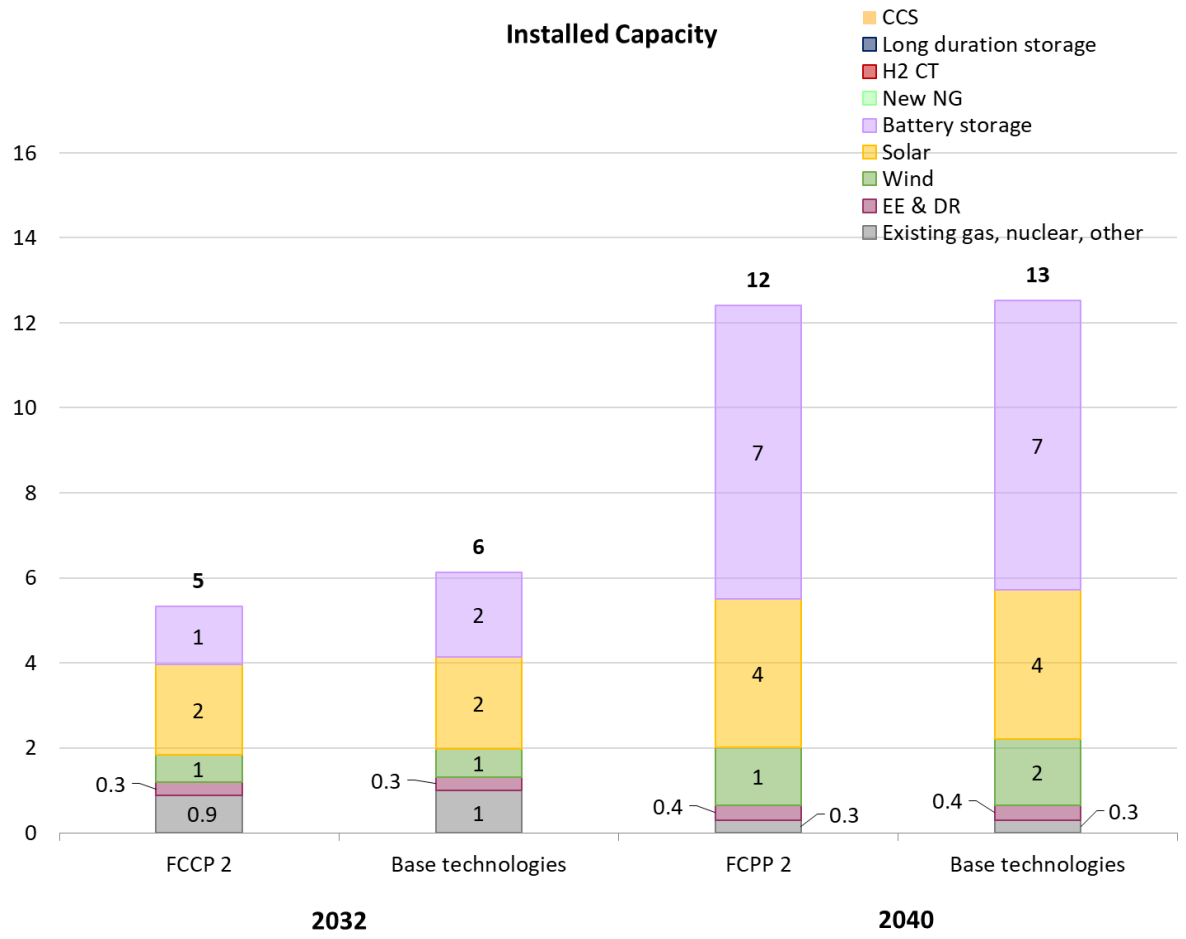


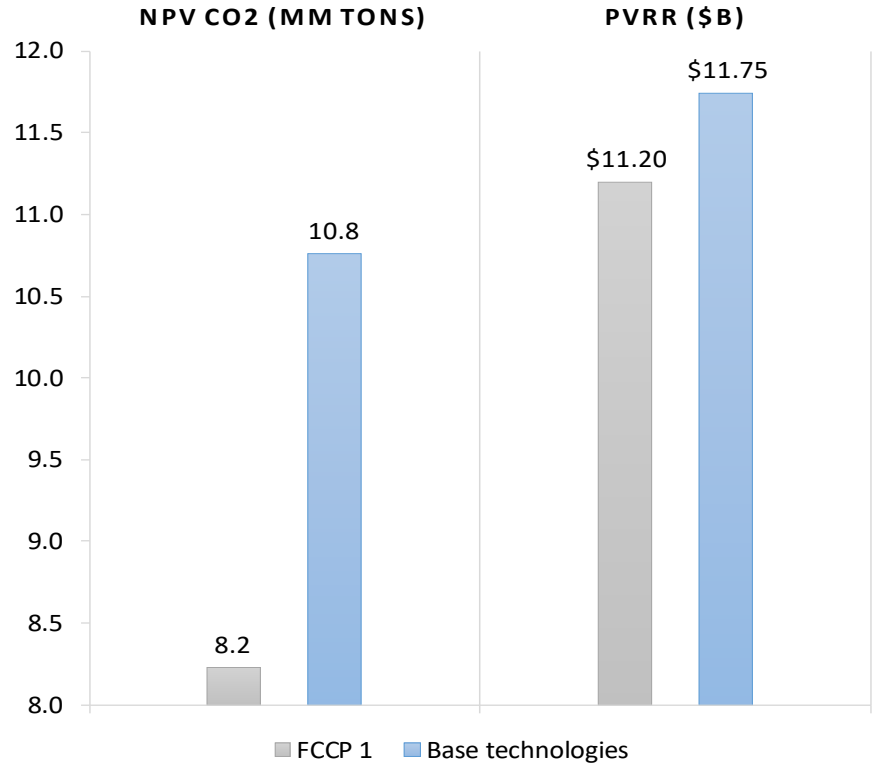


The delta in the PVRR cannot be relied upon given that the cost of Valencia and Reeves are reduced for the years post extension. Actual costs and trade-offs would be determined through a competitive solicitation.

PNM Talk to us. PNM.com

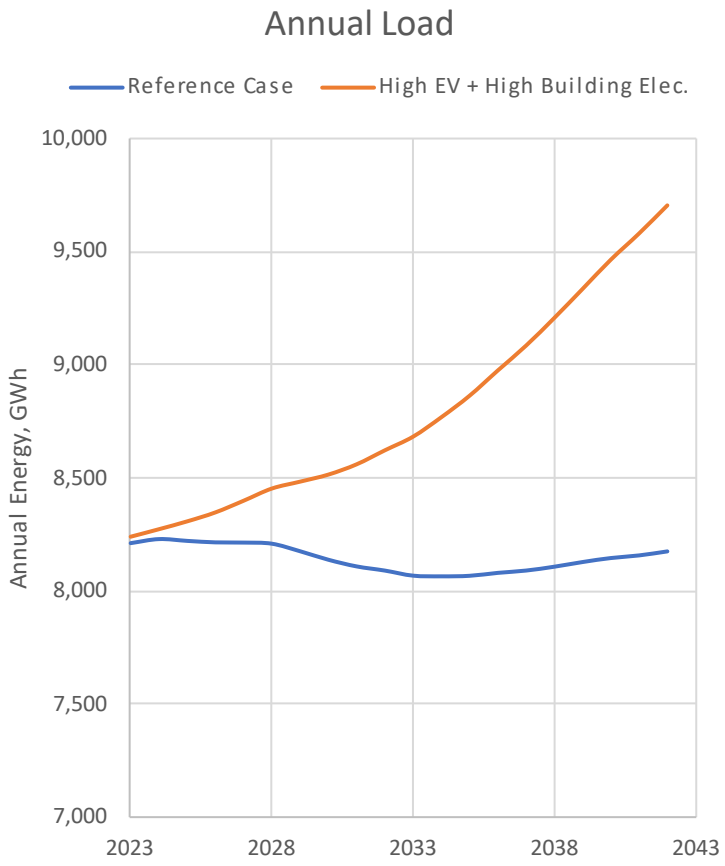
STAKEHOLDER-REQUESTED SCENARIOS: FCPP EXIT 2027 + VALENCIA & REEVES EXT TO 2039



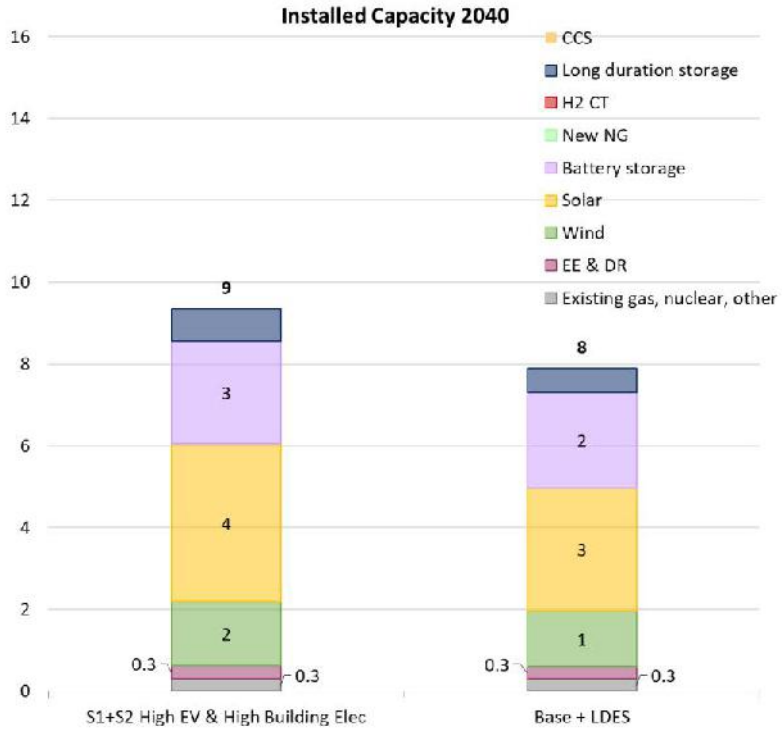


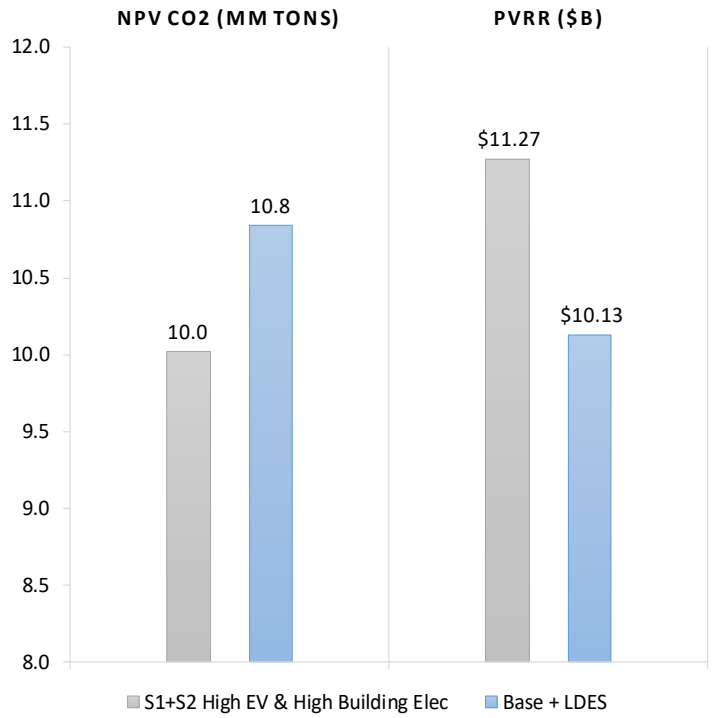
The delta in the PVRR cannot be relied upon given that the cost of Valencia and Reeves are reduced for the years post extension. Actual costs and trade-offs would be determined through a competitive solicitation.

STAKEHOLDER-REQUESTED SCENARIOS: S1+S2 HIGH EV & HIGH BUILDING ELECTRIFICATION



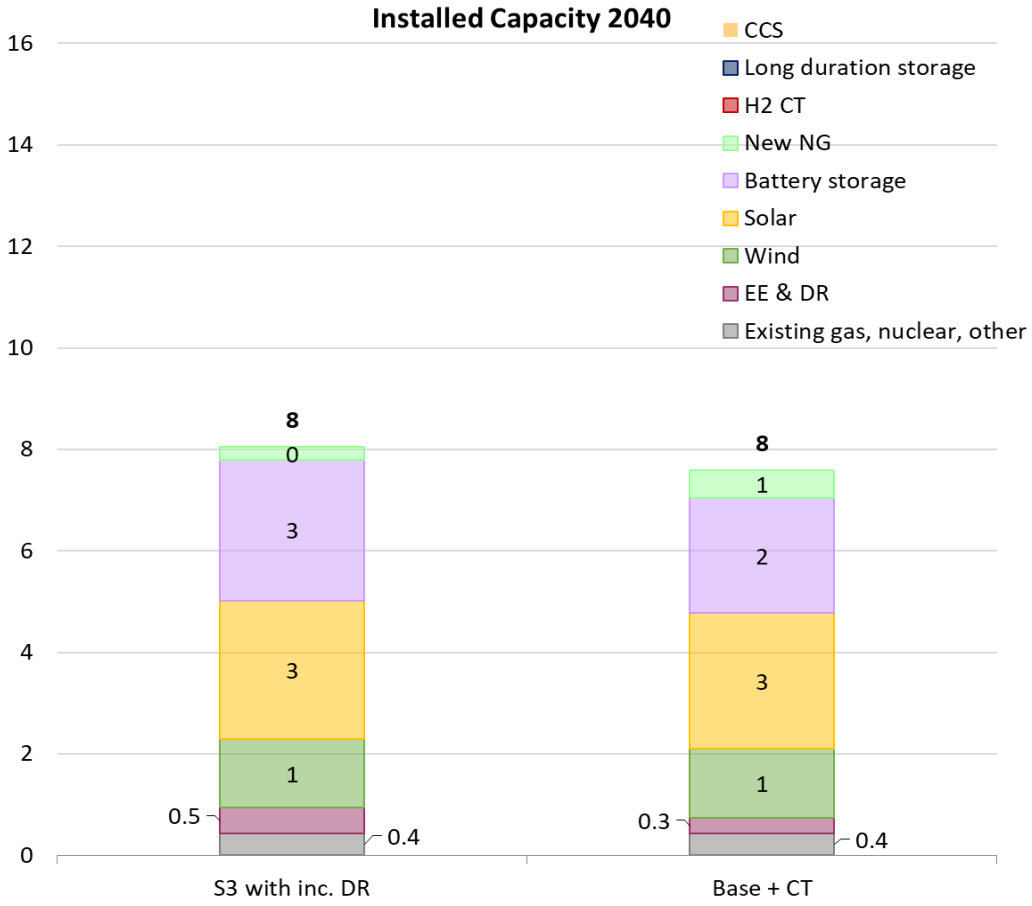
UPDATED GRAPHIC

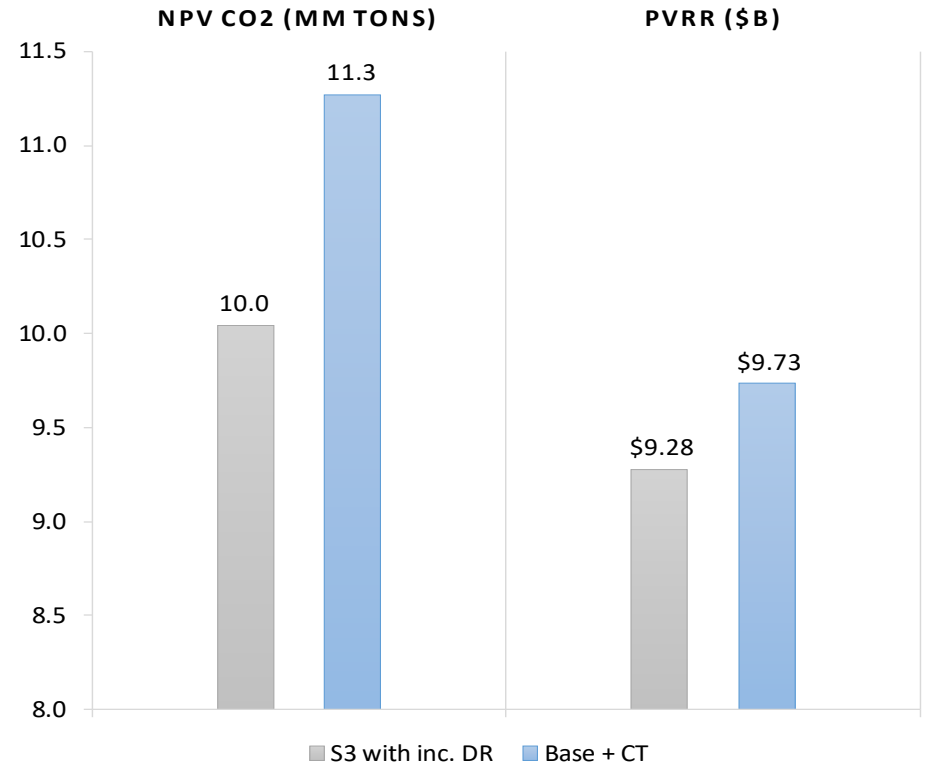




PNM Talk to us. PNM.com

STAKEHOLDER-REQUESTED SCENARIOS: S3 WITH NEW DR





The implied value of additional Demand response varies with time but ranges between ~ $140 /kw-yr - $180/kw-yr

Preliminary results

PNM'S INITIAL OBSERVATIONS & NEXT STEPS

PNM MODELING PHASE 3 – SENSITIVITY RESULTS

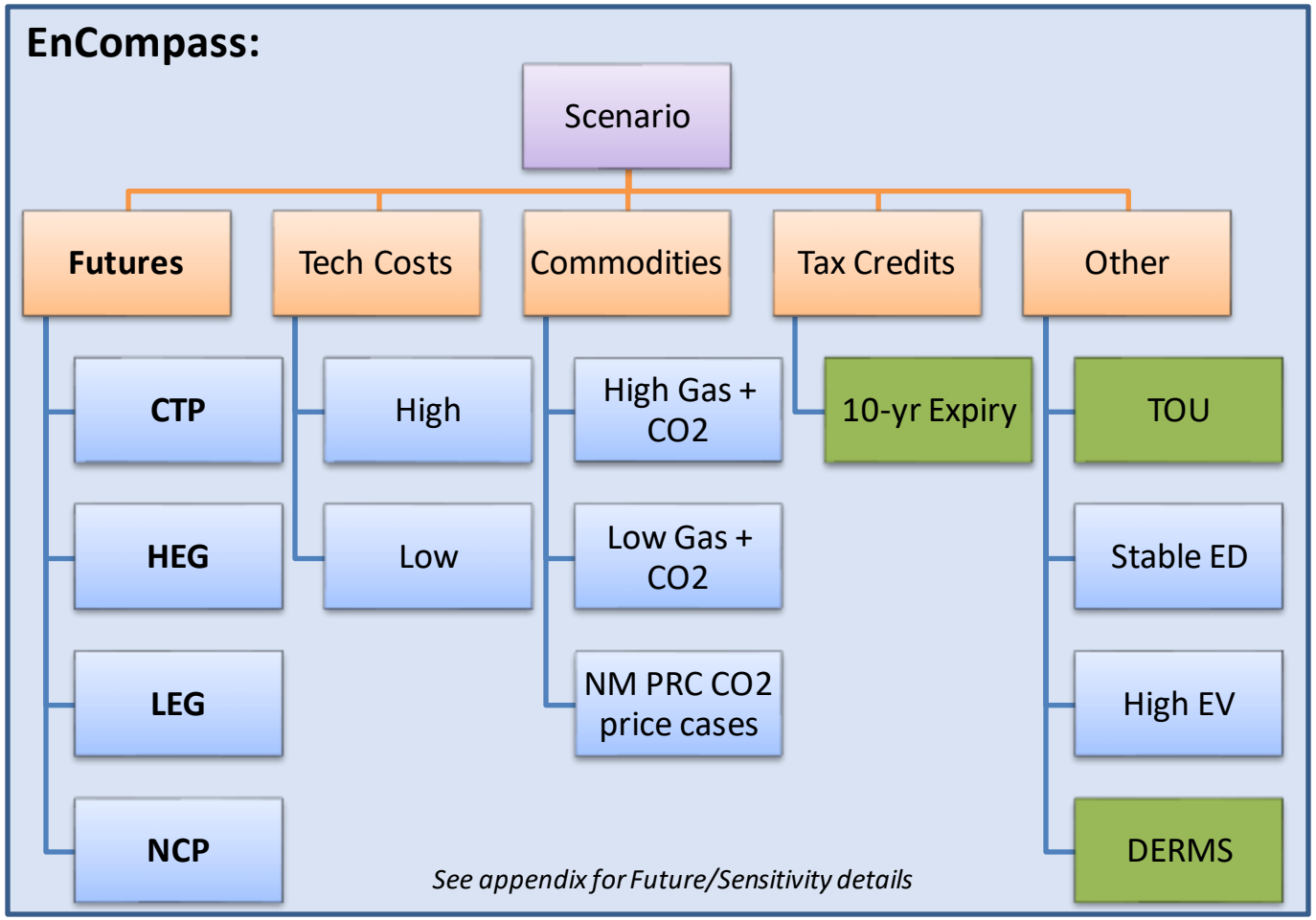
Talk to us.

FIVE SCENARIOS FOR PHASE 3 MODELING

Base technologies only	Base technologies + CTs	Base technologies + all LDES *(stakeholder scenario)*	Base technologies + all LDES + CTs	Base technologies + LDES + NG + CCS
Resource options	**Resource options**	**Resource options**	**Resource options**	**Resource options**
• Solar • Wind • 4-hr storage • EE/DR	• Solar • Wind • 4-hr storage • EE/DR • CT	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 70-hr • PHS 8-hr • IAS • LAES • Thermal storage	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 70-hr • PHS 8-hr • IAS • LAES • Thermal storage • CT	• Solar • Wind • 4-hr storage • EE/DR • CAES • Flow battery • PHS 8-hr • PHS 70-hr • IAS • CT • Linear generator • Wind exp. • Afton CCS

Near-final results

PHASE 3 MODELING – SENSITIVITY ANALYSIS (FOCUSED RESULTS)



10-yr Expiry of Tax Credits (ITC and PTC)

- Assume no ITC or PTC for applicable resources added after 2035

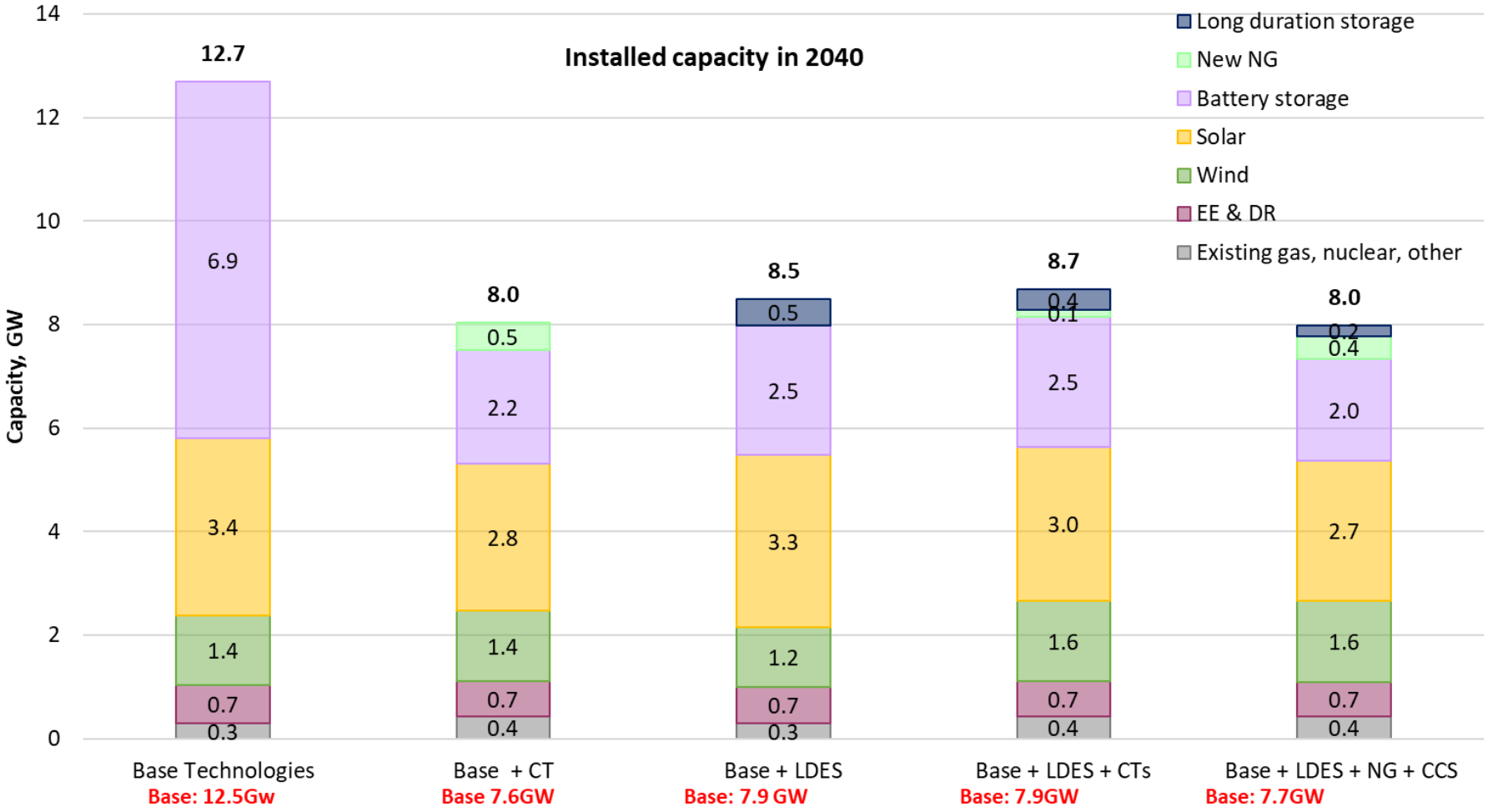
TOU (Time Of Use) Rates

- Introduce residential TOU pilot rates in 2025 and full programs beginning 2030
- On-peak 5-8am and 5-8pm
- Whole house EV Rate (10pm-5am)
- Assume 20% opt-out and 80% use TOU

DERMS (Distributed Energy Resources Management System)

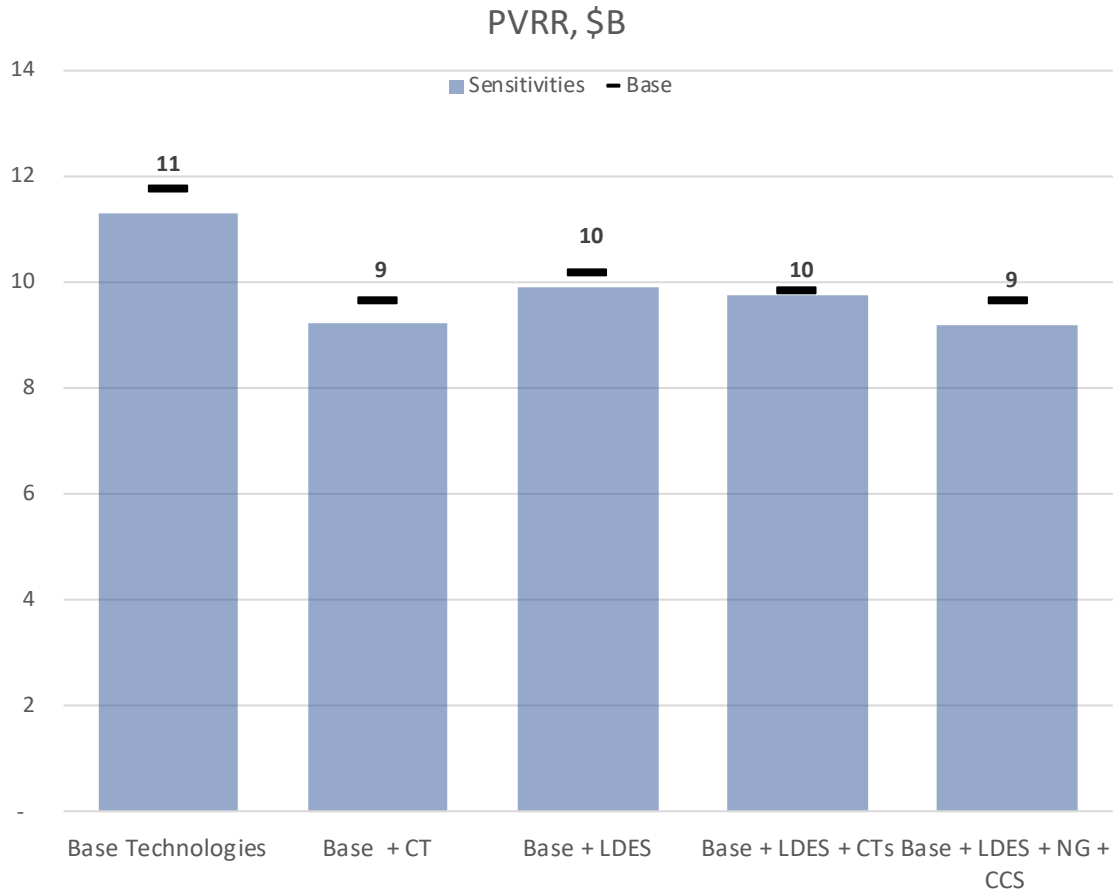
- Assumes TOU rate structure embedded in load forecast
- Assumed 25% of PV-DG customers installed customer sited BESS to be controlled by PNM for system benefits

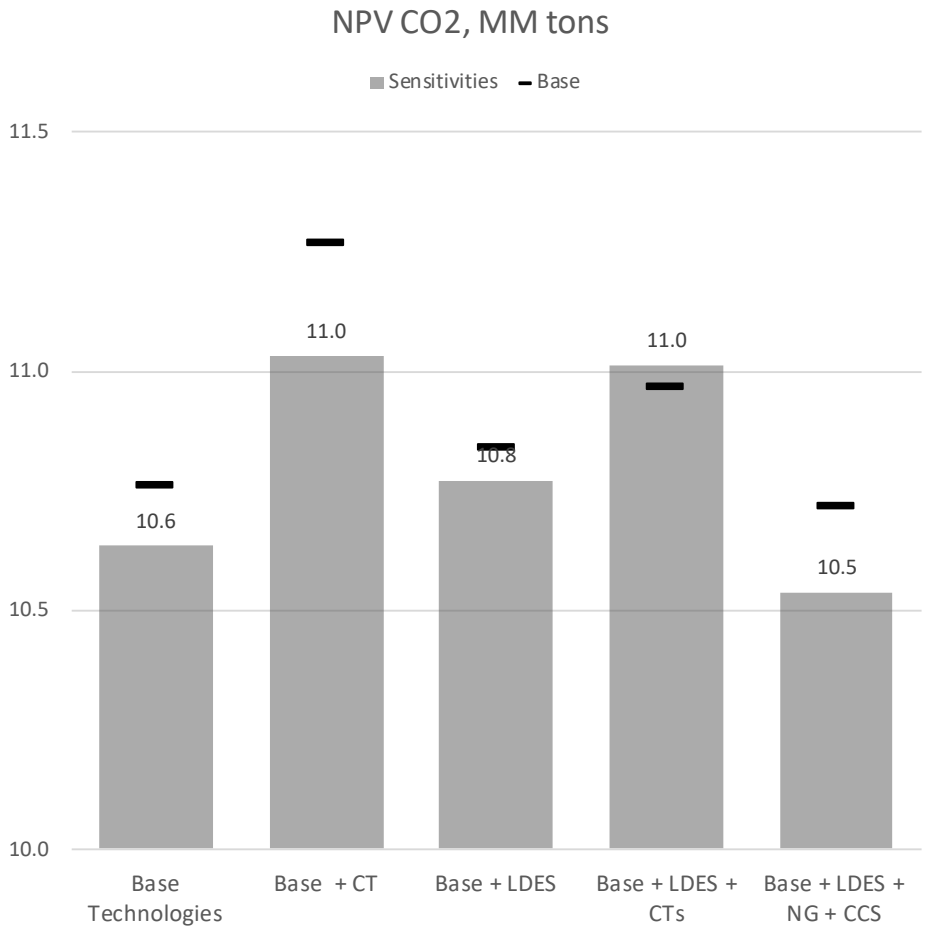
DERMS SENSITIVITY RESULTS



Summary: The addition of DERMS has a minimal impact on the total installed capacity

DERMS SENSITIVITY RESULTS

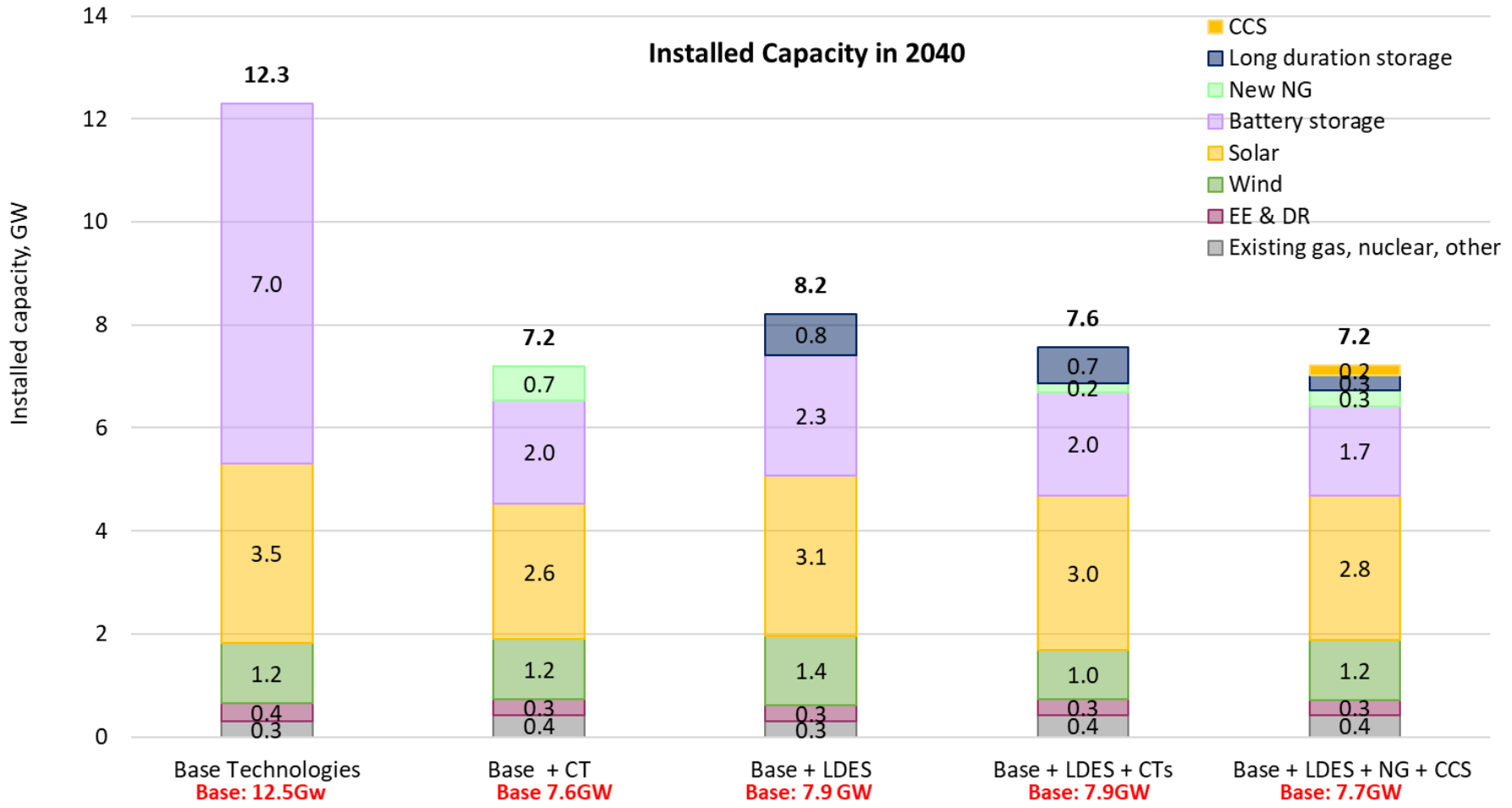




Conclusion: DERMS has a positive impact on carbon and would need to be implemented for less than the reduction in PVRR

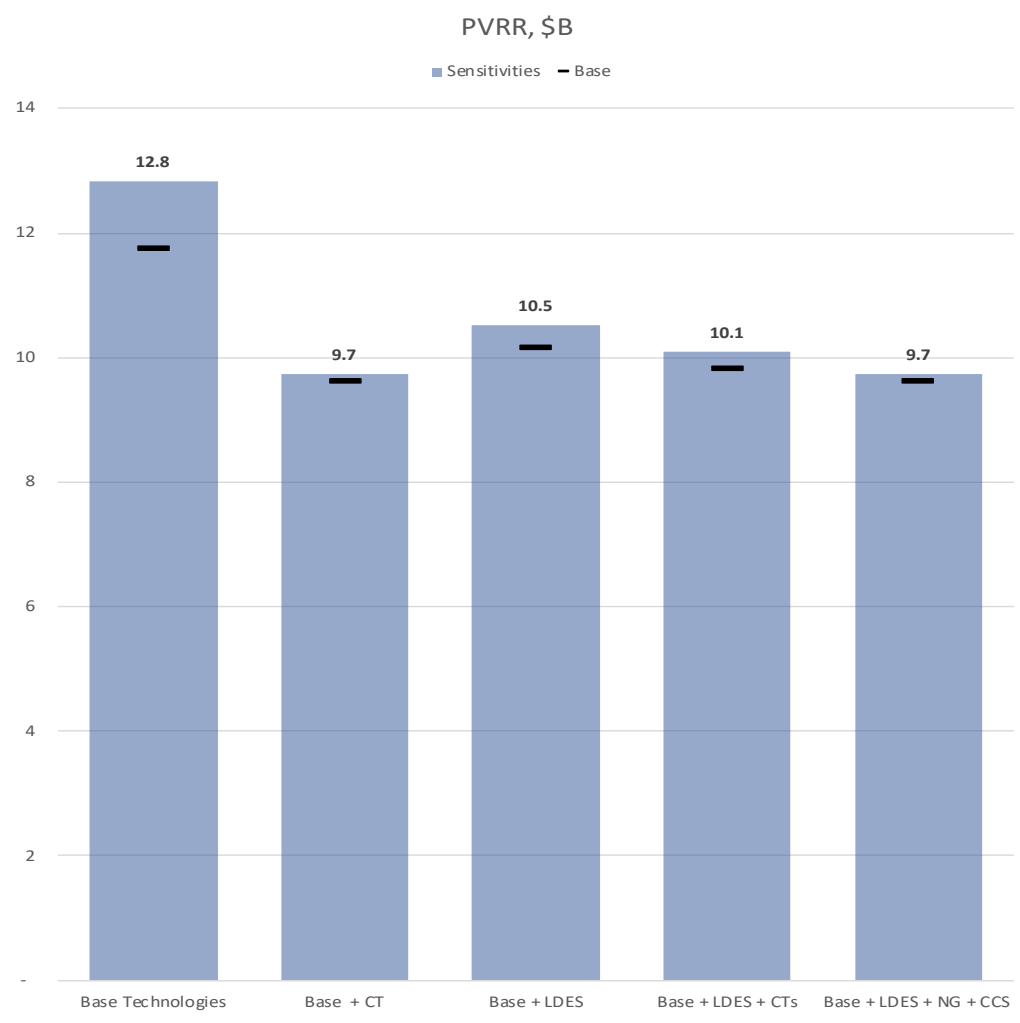
PNM Talk to us. PNM.com

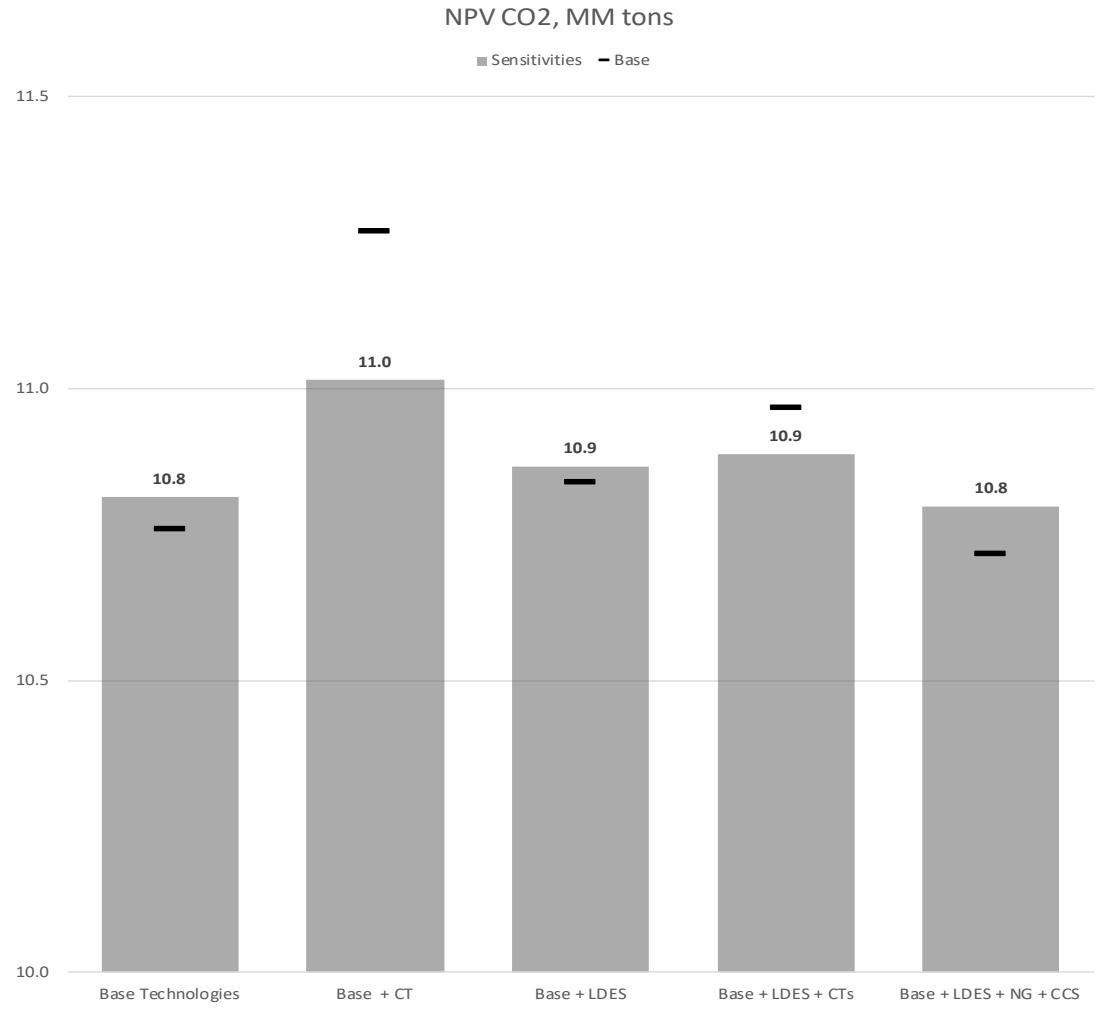
TAX CREDITS SENSITIVITY RESULTS



Summary: Expiration of Tax Credits generally results in less installed capacity in 2040

TAX CREDITS SENSITIVITY RESULTS

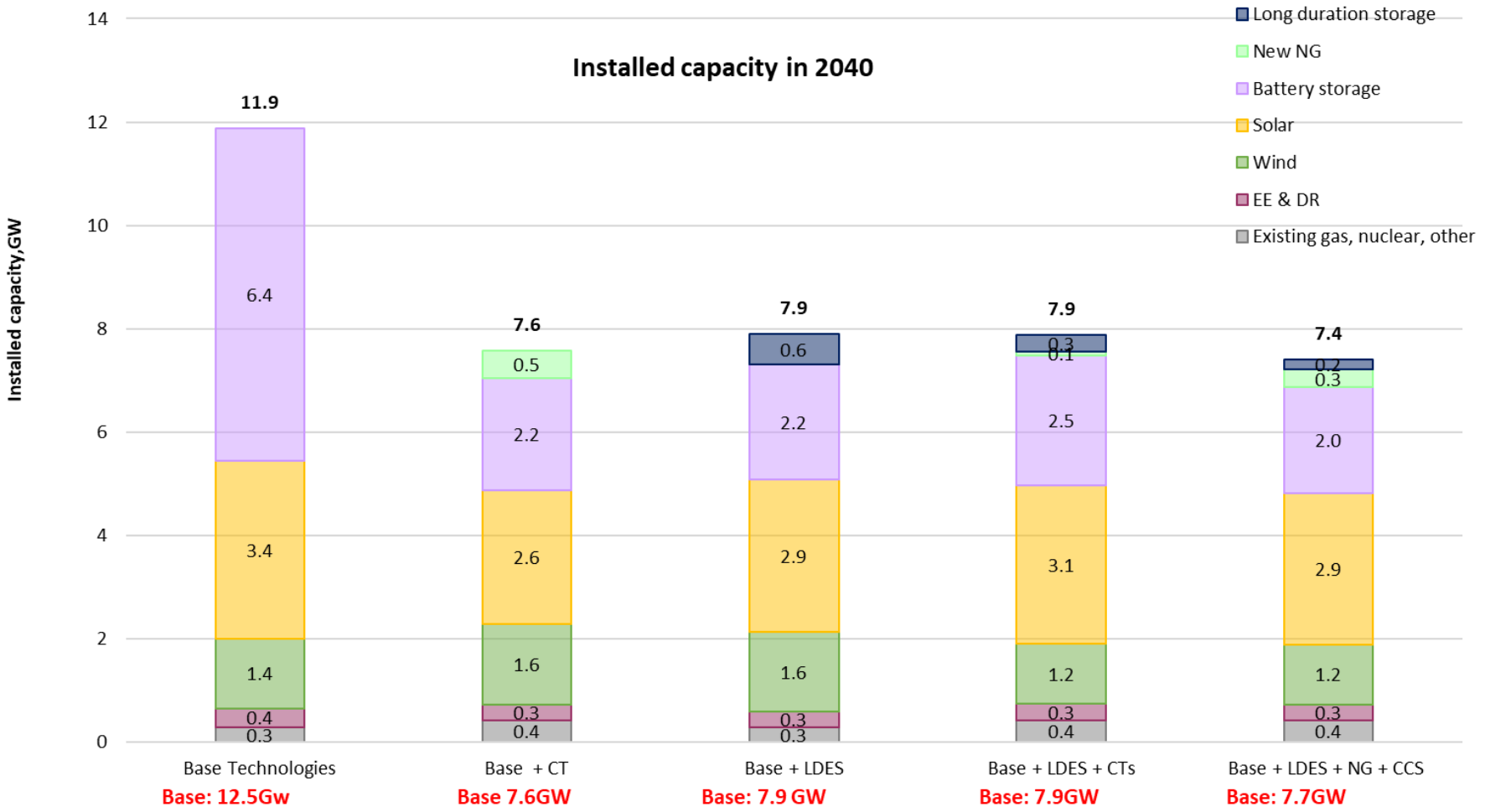




Conclusion: Expiration of tax credits have a negligible impact on revenue requirements and CO2

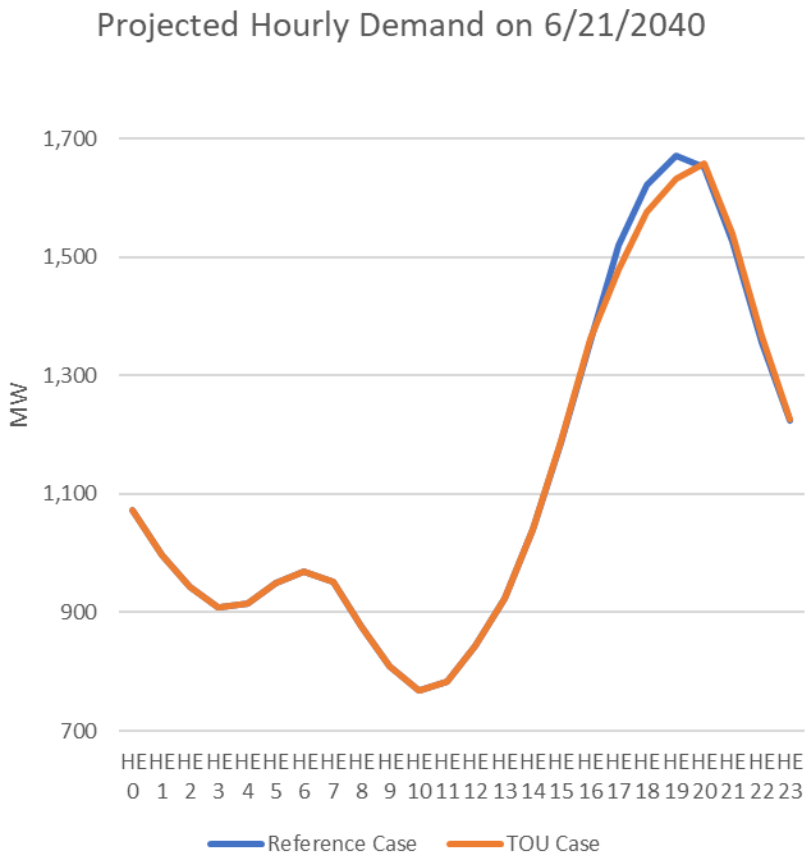
Talk to us.

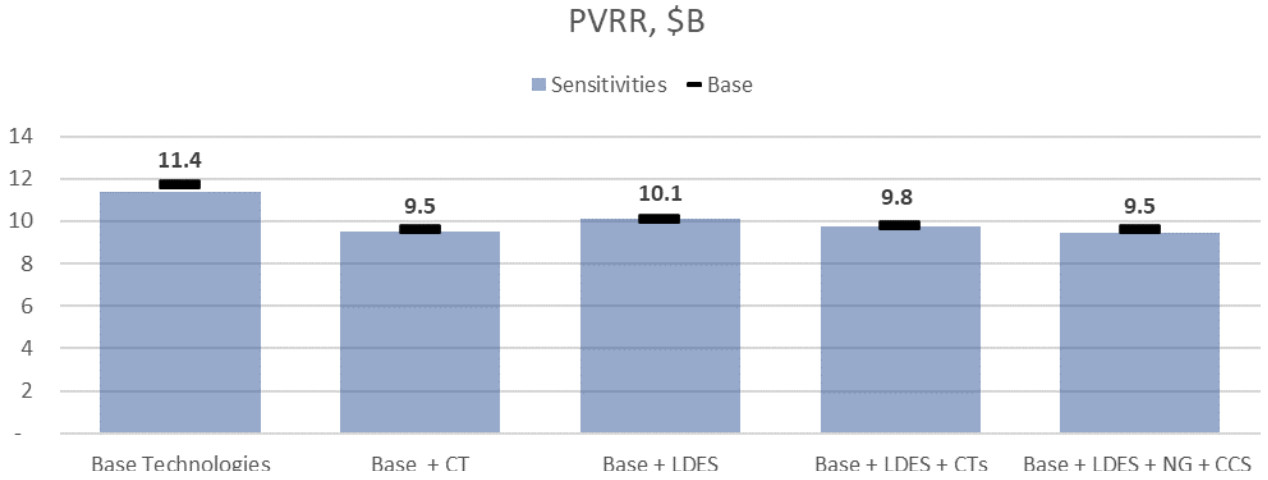
TIME OF USE SENSITIVITY RESULTS

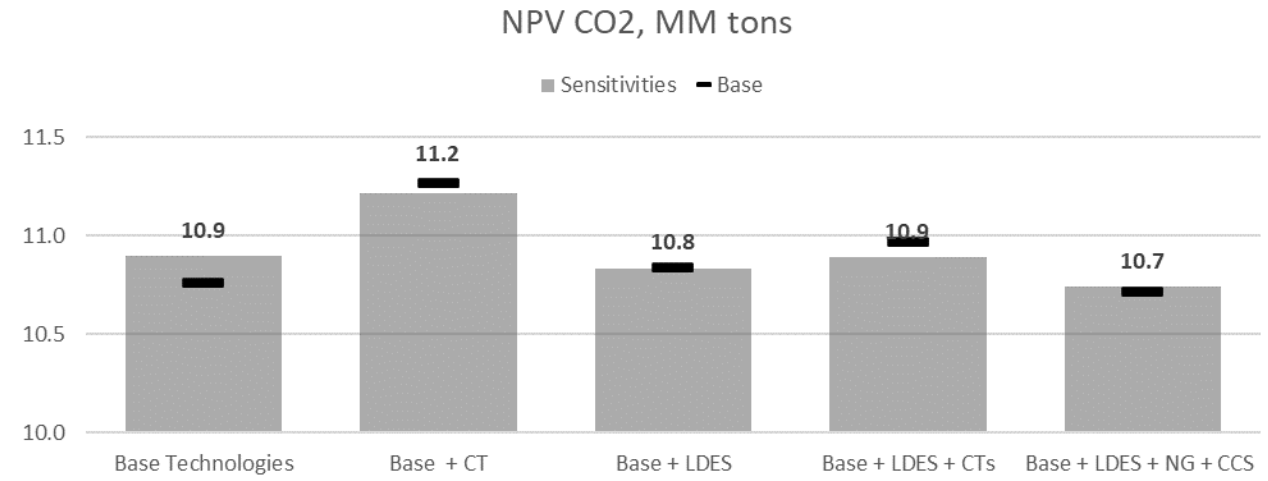


Summary: Time of Use rates generally results in a smaller capacity build due to reduced peak demand

TIME OF USE SENSITIVITY RESULTS







Conclusion: Time of Use rates results in a slight decline in Revenue requirements and negligible change in CO2

STATEMENT OF NEED AND ACTION PLAN

STATEMENT OF NEED

Stakeholder's Statement of Need Outline Sections	Is this an explicit requirement of the Statement of Need?	If not, where will it be address in the PNM IRP?
2. Vision and Goal	No	Chapter 1.2
3. Identified Decision Points and Pathways	No	Chapters 2.1, 2.3, 3.3, & 5.1
4. Resources	No	Chapter 6
5. Potential New Resources	No	Chapter 6
6. System Needs	Yes	Chapter 7
7. Preferred Portfolio - Refer to appendix of resource evaluation	No	Chapter 7

We agree with many of the stakeholder's points within their draft SoN. Here's where it should belong in the SoN and where the rest belong in the IRP

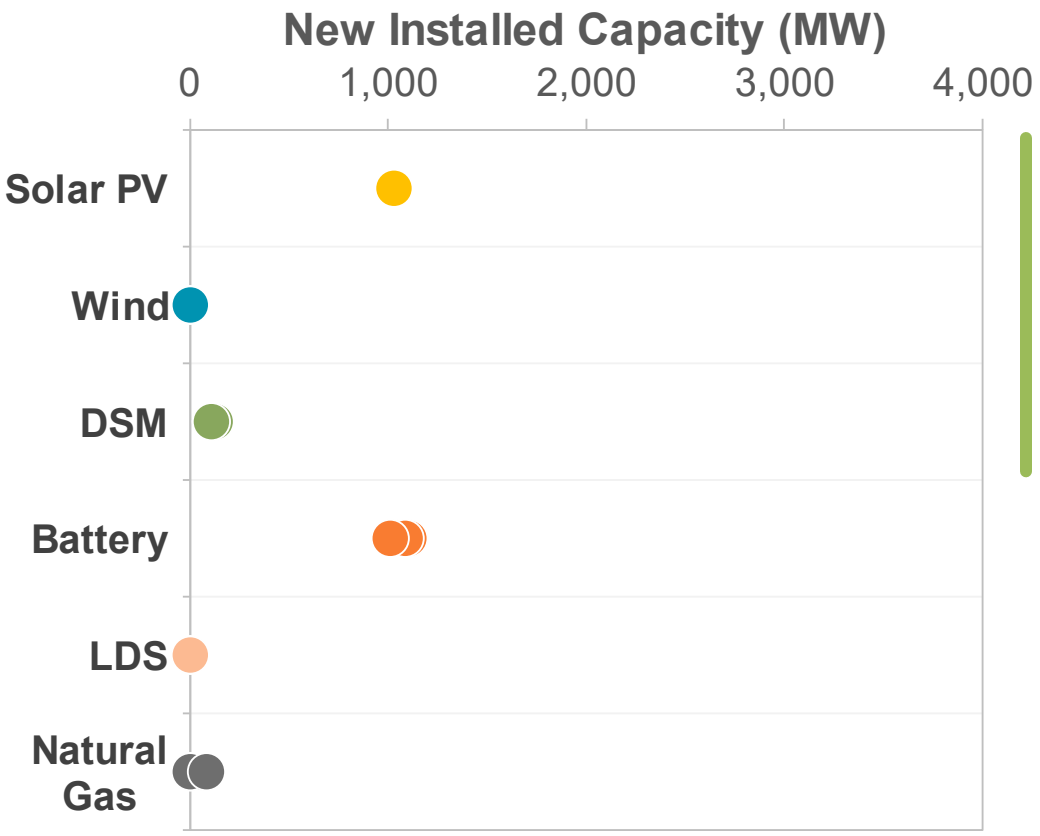
Many of the stakeholder's points in these sections are incorporated in these sections within the IRP

While this is important, this is an explicit requirement of the IRP rule under Section 17.7.3.8 B(5), independent from SoN and represented in the IRP

This is critical to the Statement of Need and explicitly described within the SoN IRP ruling.

An outcome for the IRP but not in the scope in the SoN

POTENTIAL RANGE OF CUMULATIVE NEW CAPACITY BY 2028 (CTP CASE)



Most resource needs in the near term have been satisfied with solar and storage procured through recent all-source RFP solicitations; range of uncertainty is relatively narrow.

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

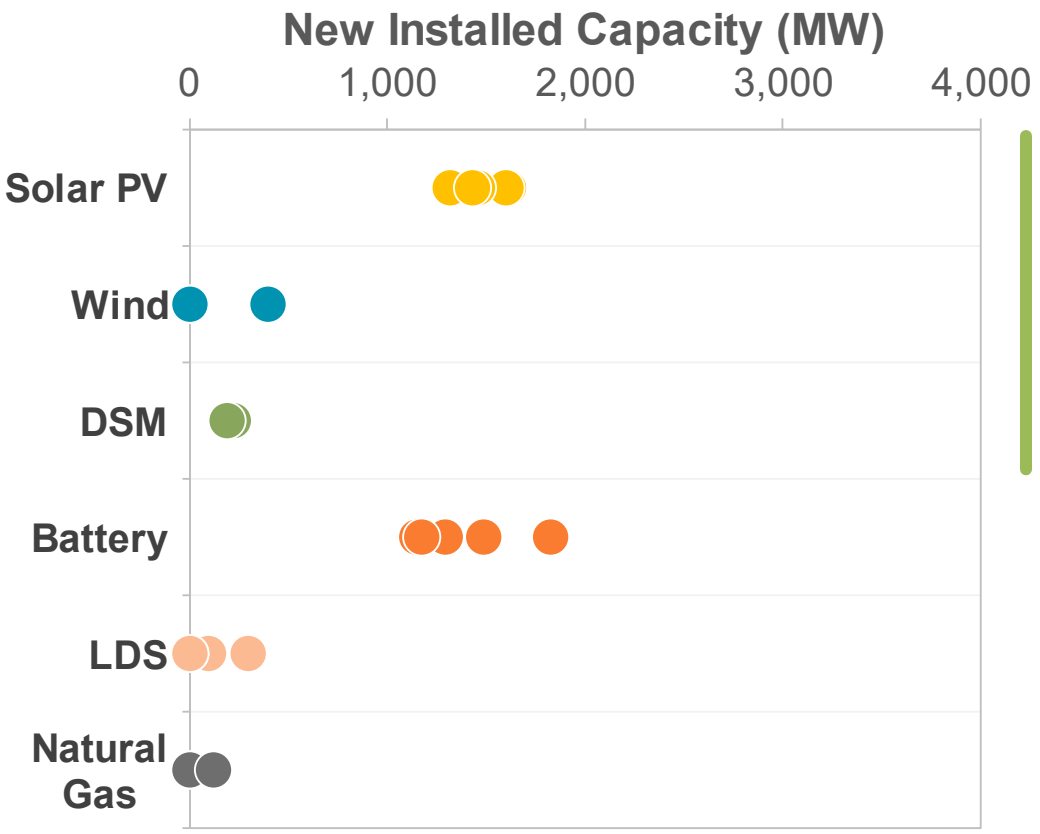
Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

POTENTIAL RANGE OF CUMULATIVE NEW CAPACITY BY 2032 (CTP CASE)



In the medium term, value of resource diversity becomes apparent, as resource selections include capacity from all technology segments

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

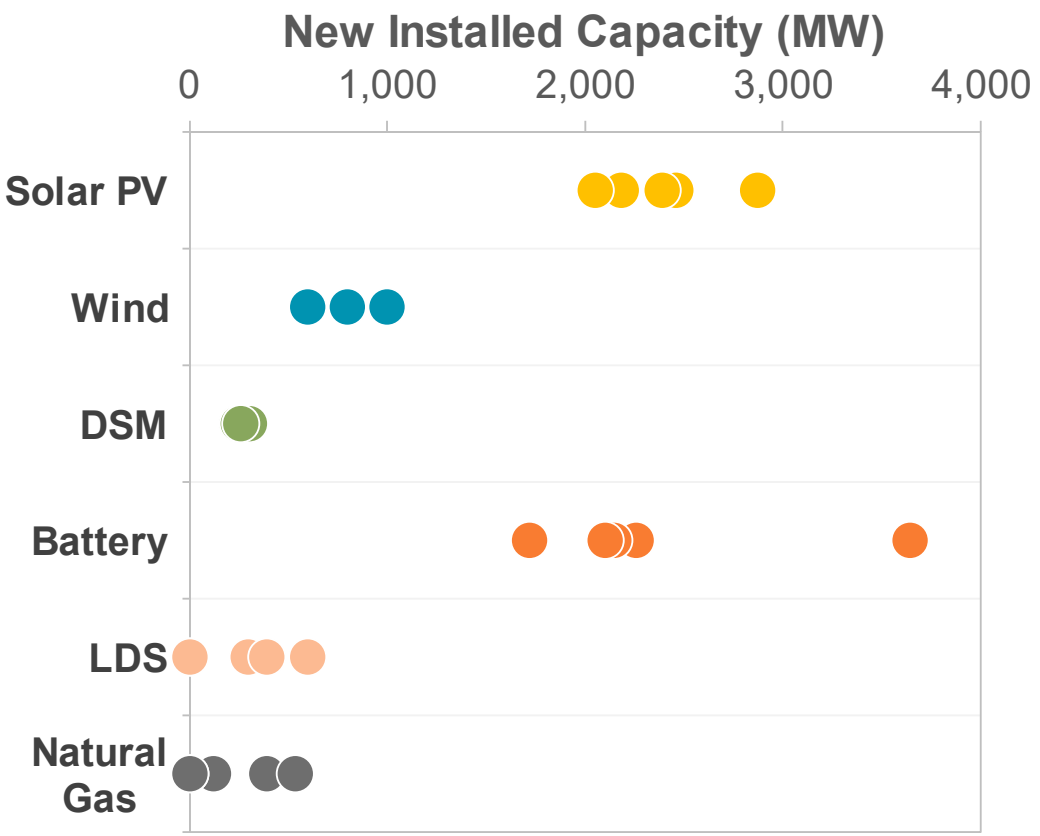
Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

POTENTIAL RANGE OF CUMULATIVE NEW CAPACITY BY 2040 (CTP CASE)



In the long term, significant capacity additions are needed to meet carbon-free goals and ensure reliability; scenarios continue to show a wide range of outcomes

POSSIBLE ACTION PLAN ITEMS

1. Issue an all-source RFP for resources coming online 2029–2031 time periods
    - Incorporate into the non-price scoring factors criteria related to environmental justice.
    - Incorporate bid evaluation criteria that will include reliability and resiliency assessments, fuel security, and resource diversity.
    - Utilize an independent evaluator as part of the RFP evaluation.
    - Update form contracts
    - File for resource approvals with the NMPC (PPA/CCN), balancing resource selections between utility owned and third party contracts.



2. Issue an RFI/RFP for long-lead time resources or newer technologies that could deliver between 2029-2035
    - Conduct system studies necessary for long-lead time resources, like pumped storage and wind including assessment of transmission expansion necessary to access the resources.

POSSIBLE ACTION PLAN ITEMS

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

4. Transition Resource Adequacy modeling to incorporate 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 forward showings earlier than summer of 2028, then should incorporate WRAP RA modeling into PPA and/or CN filings prior to filing its 2026 IRP.



5. Establish a stakeholder modeling workshop (or series of workshops) that will kick off no later than 9/15/2024 to inform modeling assumptions and protocols that will be utilized in the 2026 IRP. The purpose of this group will be to discuss concepts and have PNM test those concepts, if possible, to inform the group's recommendations.

POSSIBLE ACTION PLAN ITEMS

6. Evaluate the ability to create new demand response and other customer programs, including customer sited storage, interruptible rates, etc. and request regulatory approvals as necessary.

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

8. Continue to explore the ability to participate in regional markets

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

10. Conduct the 2026 IRP



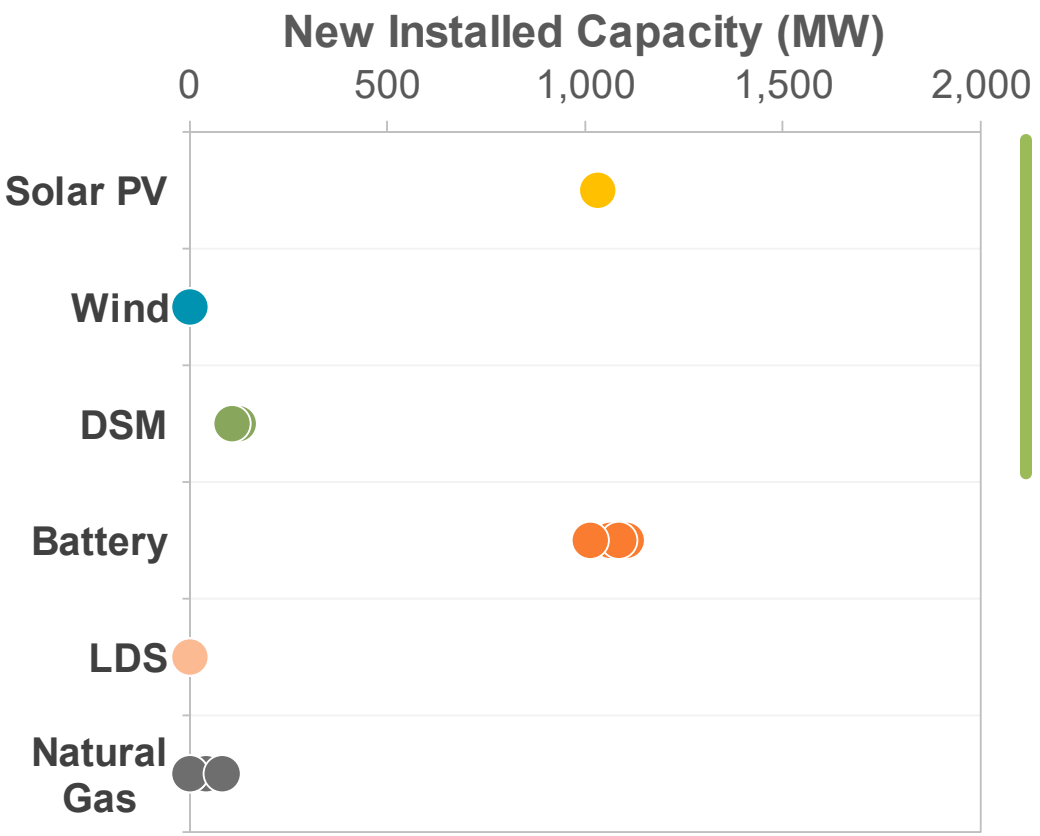
POSSIBLE ACTION PLAN ITEMS

11. Create pilot programs to explore new technologies in a limited way. PNM should explore avenues to obtain DOE funding if possible.
12. Investigate improvements to IRP process to incorporate integrated transmission and distribution system planning. (However, this does have other cons derations that must be weighed and balanced.)



APPENDIX

POTENTIAL RANGE OF NEW CAPACITY, 2023-2028 (CTP CASE)



Most resource needs in the near term have been satisfied with solar and storage procured through recent all-source RFP solicitations; range of uncertainty is relatively narrow.

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

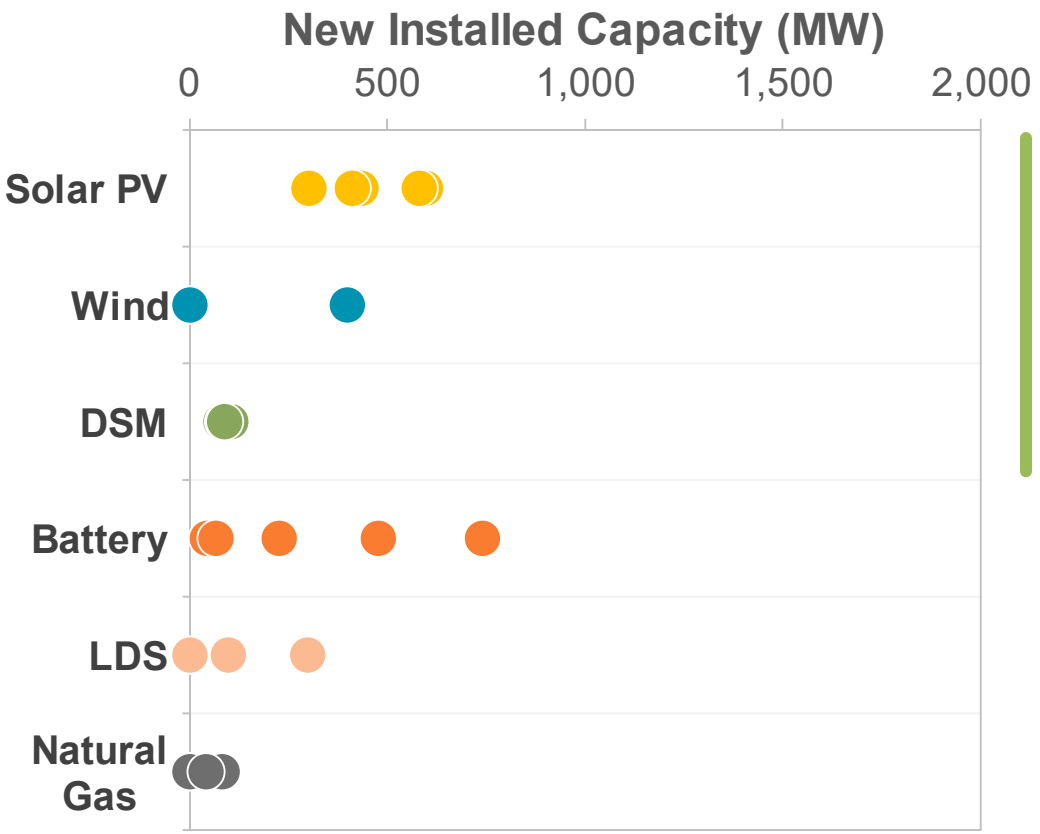
Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

POTENTIAL RANGE OF NEW CAPACITY, 2028-2032 (CTP CASE)



In the medium term, value of resource diversity becomes apparent, as resource selections include capacity from all technology segments

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

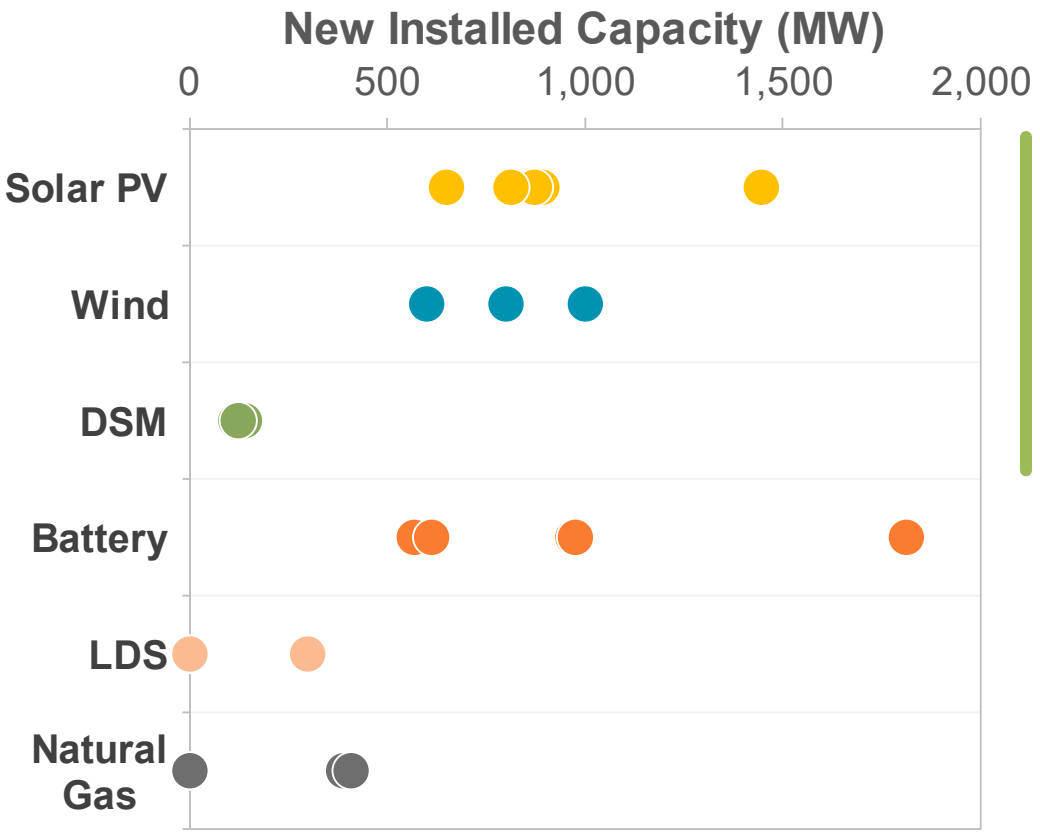
Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

POTENTIAL RANGE OF NEW CAPACITY, 2032-2040 (CTP CASE)



In the long term, significant capacity additions are needed to meet carbon-free goals and ensure reliability; scenarios continue to show a wide range of outcomes

Low-cost carbon-free energy resources

with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.

Dynamic balancing resources

that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and

Firm resources

with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

IRP@pnm.com for e-mails

Register your email on sign-in sheets to receive alerts of upcoming meetings and notices that we have posted to the website.

Thank you



Welcome!

Stakeholder Engagement Comment Session

Follow up from Sept. 28 Meeting

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Friday, Oct. 6

9:00 AM – 10:00 AM Mountain Daylight Time

Note: this meeting is being recorded and will be available as public information. The link to the recording will be posted on the Gridworks website under the Sept. 28 meeting.

Purpose and Structure of Today's Meeting

Hear comments from stakeholders on the Statement of Need and Action Plan as presented by PNM at the Sept. 28 meeting.

Stakeholders will be given the opportunity to comment verbally and submit comments via the meeting chat.

Stakeholders are strongly encouraged to voice any areas of disagreement.

Key Questions for Stakeholder Comment

For the Statement of Need:

Slide Deck – PNM 2023-2042 IRP: Modeling Results Update – 9/28/23

Are the projected quantities and types of new capacity needs appropriate for the timeframes (thru 2028, 2028-2032, 2033-2040)

- Do you believe the projected capacity additions are reasonable?
- Do you believe the projected types of resources are reasonable?

For the Action Plan:

DRAFT #2 – PNM Action Plan Mapping Worksheet

- Have the action items that are important to you been captured in the worksheet?
- Are there wording changes you would like considered?

Final Steps in the Facilitated Stakeholder Process

- **Oct. 19, 9 – 10:30 AM – Update on SoN & Action Plan by PNM**
- Dec. 15 - IRP is filed by PNM
- Dec. 19, 9 - 10:30 AM - Final stakeholder meeting to collect input regarding how you experienced the process
- Jan. 31, 2024 – Gridworks report due to the NM PRC. It will include results of both NM IRP Facilitated Stakeholder Processes (PNM and SPS).

Thank you for attending.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

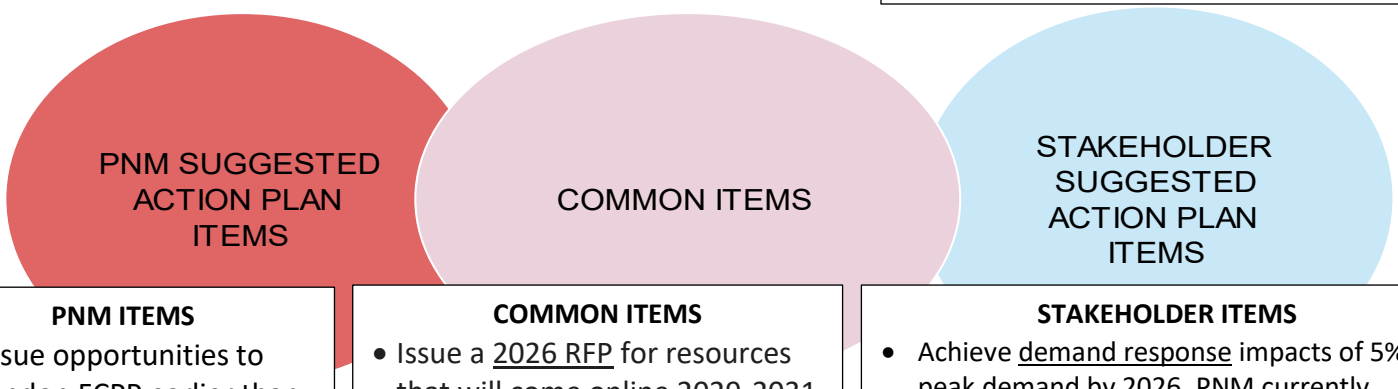
GRIDWORKS

Materials for this and future meetings available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

Proposed Framework for Action Plan Items

2023_09_28 DRAFT1

Yellow highlights are items that seem to fit in common item column but need to be discussed with PNM team.



PNM ITEMS

- Pursue opportunities to abandon FCPP earlier than 2031 as available and in the interest of customers.
- Assess the ability to add capacity at PNM's existing plant sites.
- Assess the need to utilize other reliability metrics in planning.
- Conduct the 2026 IRP
- Create pilot programs to explore new technologies in a limited way. PNM should explore avenues to obtain DOE funding if possible.

COMMON ITEMS

- Issue a 2026 RFP for resources that will come online 2029-2031
  - Incorporate into the non-price scoring factors criteria related to environmental justice. (see question 2 below)
  - Incorporate bid evaluation criteria that will include reliability and resiliency assessments, fuel security, and resource diversity.
  - Utilize an independent evaluator as part of the RFP evaluation.
  - Update form contracts
  - File for resource approvals with the NMPC (PPA/CCN), balancing resource selections between utility owned and third-party contracts.
  - QUESTION 1: WILL GEOTHERMAL , LANDFILL GAS AS A FUEL, AND THERMAL STORAGE BE INCLUDED AS OPTIONS?
  - QUESTION 2: WILL FEDERALLY DESIGNATED (IRA) ENERGY COMMUNITIES BE CONSIDERED AS PRIORITY?
- Issue an RFI/RFP for long-lead time resources or newer technologies that could deliver between 2029-2035
  - Conduct system studies necessary for long-lead time resources, like pumped storage and wind including assessment of transmission expansion necessary to access the resources.
  - QUESTION: WILL OTHER LDS OPTIONS BE INCLUDED?
- Continue to explore the benefits of and ability to participate in regional markets, including during extreme weather.
- Evaluate the ability to create new demand response and other customer programs, including customer sited storage, interruptible rates, etc. and request regulatory approvals as necessary. Solicit new DR programs with flexible requirements by mid-2024.

STAKEHOLDER ITEMS

- Achieve demand response impacts of 5% of peak demand by 2026. PNM currently achieves demand response reduction of approximately 3% of peak demand. To reach this goal, PNM should solicit new DR programs with flexible requirements. This new solicitation should go out by mid-2024.
- By 2026, PNM shall have a default time of day rate for all customer classes. PNM shall assess the success of the time-of-day pilot and develop a plan to enroll all customers on a time-varying rate.
- Develop a list of advanced geothermal developers and ensure they are contacted for future RFI's. Develop a relationship with the advanced geothermal development community in the state.
- Solicit geothermal bids and bids for a variety of thermal storage technologies.
- Long duration storage - converge on desired resource characteristics then put out another RFI for narrowing to alternatives that are viable for inclusion in a future RFP and/or bilateral procurement where warranted.
- Evaluate the most promising, maturing carbon free technologies like thermal or iron-oxide storage.
- Convert fossil fuel plants to long duration energy storage as environmental justice for impacted communities.
- Collect distribution feeder level reliability metrics to understand reliability equity.
- Initiate public information effort regarding electricity sector changes and IRP process.
- Explore availability of landfill gas as supplementary/replacement fuel
- Share transmission assumptions with stakeholders and allow developers to give feedback and least-cost site projects.
- Commit to an energy community focus in solicitations (IRA federally designated – make a priority)

Yellow highlights are items that seem to fit in common item column but need to be discussed with PNM team.

PNM ITEMS, NEXT IRP

-

COMMON ITEMS, NEXT IRP

- Establish a stakeholder modeling workshop (or series of workshops) that will kick off no later than 9/15/2024 to inform modeling assumptions and protocols that will be utilized in the 2026 IRP.
- Transition Resource Adequacy modeling to incorporate WRAP forward showing planning requirements and resource attributes no later than PNM's 2026 IRP.
- Investigate improvements to IRP process to incorporate integrated transmission and distribution system planning. ADD DETAILS, DATES, MECHANISMS, HOW TO MANAGE APPROPRIATE PUBLIC ENGAGEMENT GIVEN DATA SHARING RESTRICTIONS (FERC).

STAKEHOLDER ITEMS, NEXT IRP

- Upgrade models and software so PNM can model 8760 hours during the capacity expansion phase.
- Refine modeling parameters including forced outage rates and chemical degradation over time for BESS resources.
- Include future PPA procurement in the modeling process in addition to the assumption that PNM will own new resources.
- Improve financial modeling so it accurately represents the cost difference between a 60-year lifetime resource and a 20-year lifetime resource.
- Incorporate consideration of correlated gas outages
- Include extreme weather considerations.
- Use a better transmission model.

PNM IRP Statement of Need - Draft Themes & Outline

2023-05-26

The PNM Integrated Resource Plan 2023 [IRP-2023] [provides/brings] the [best/furthest] long range path for building out the strongest, most reliable electrical power delivery system for our customers over the next 20 years as we can envision [in 2023/now]. The IRP report begins with the current status of PNM's system, and shows how available resources and technologies can bring improvements. Simultaneously we recognize that changes are occurring in most every sector of the environment in which we operate. These will require ongoing re-evaluation and modifications to the 2023 IRP plan that will be incorporated in future triennial PNM IRPs.

Meeting our clean energy goals and preserving system reliability while providing for the growing needs of our customers in an affordable manner will require the addition of significant amounts of new generation capacity over the next twenty years. We anticipate that over the seventeen years between today and 2040, the likely amount of new installed generation capacity will total between 4,000 to 5,000 MW or more. This amount of *new* capacity is significantly greater than the amount that exists today, implying that the achievement of our goals will require continuous and significant evolution of our portfolio.

[Brief summary of planning requirements (reliability/RA/Resiliency, cost, environmental, others)]

The types of resources that we expect procure to meet those needs will represent a diverse mix of technologies and capabilities that will generally fall into three categories:

- **Low-cost carbon-free energy resources** with the capability to produce clean energy to meet a majority of our customers' needs throughout the year.
- **Dynamic balancing resources** that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand; and
- **Firm resources** with the capability to operate at or near full capacity for extended periods of time that will allow our 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 renewable output.

The specific technologies that we will procure to fill these needs will depend upon a number of factors.

[Discussion on factors/scoring criterion]

Based on what we currently know and expect for the for the future, our Most Cost Effective Plan reflects our best vision of what resources would fulfill these needs. The MCEP includes **[grouped in to low-cost**

carbon free resources, firm dispatchable resources, and balancing resources and breakdown MW ranges by time period: Action plan period (through 2027), 2028-2033, 2034-2042. Placeholder for Resiliency resources].

[Stats on MCEP portfolio with focus on additions and why these meet the planning requirements]

While our MCEP reflects our current view of the most cost-effective viable pathway to 2040, there are a multitude of uncertainties that may change the composition of the portfolio that best meets the combined goals of our planning processes. By studying a diverse range of scenarios in this IRP, we intend to equip our planners with information needed to understand the full range of options and the factors that might lead us to deviate from our current MCEP. Across all viable pathways to our 2040 goal and the numerous futures and sensitivities that we studied, the range of plausible resource needs is indeed broader:

[Figure showing ranges of technology needs through 2032, 2042]

This MCEP, coupled with the diverse outcomes in alternative plausible portfolios, informs an Action Plan that is intended to further our progress towards our goals while preserving optionality to adjust to changing market circumstances.

PNM will issue an All-Source RFP to identify the specific set of resources to best meet the needs defined above [low-cost carbon free resources, firm dispatchable resources, and balancing resources].

Integrated Resource Plan:
Statement of Need Table of Contents
Working group suggestions for Public Service New Mexico - August 28, 2023

Statement of Need 17.7.3.10

- 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.
- 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.

Table of Contents

1. Introduction

The Statement of Need [Son] is a new PRC-required section in PNM's 2023 IRP filing. The SoN provides the inputs of a self-selected group of ~250 external persons called the IRP External Advisor Group [EAG] who represent the public, governmental agencies, and parties with interest in the long term planning by PNM. PNM is a wholly owned, regulated power-generating subsidiary of the holding company PNMR that provides approximately 2,000 MW of electrical power to more than 525,000 residential and business customers in central and northern New Mexico.

The EAG has reviewed the results/recommendations of the 2023 modeling process. This SoN 2023 includes:

a) Examination of identified generation and storage resources to maintain PNM as the reliable [24/7/365] provider of low-carbon power at the least cost to its rate paying customers. See Comprehensive Table of Resources;

b) Response to PNM's preferred 2023 plan/portfolio;

c) Additional resources not included in the 2023 modeling;

d) Other considerations related to the transition from fossil fuels in PNM's power generation portfolio in the short term planning period until 2026 and the IRP twenty year planning horizon until 2043;

e) Items for Future Discussion, beyond this IRP, that the EAG identified for monitoring and possible inclusion in future PNM IRPs.

2. **Vision and Goals**
    a. The identification of a set of resources and a sequencing of those resource deployments that conforms to the regulations and policies of the State of New Mexico, reliably serves all customers at a reasonable cost with electrical energy that is that is resilient in the face of national security, technology, infrastructure, resource, cyber and environmental constraints.
    b. Goals
        i. Support Rapid Decarbonization & Electrification
        ii. Reliability and Resilience: Utility's Obligation to Serve
            1. Minimum Reserve Requirements
            2. Reliability Standards
            3. Swift recovery from climate or security threats
        iii. Public Interest and Equity
            1. Responsibilities to Ratepayers and Stakeholders
                a. Affordability
                b. Availability to Underserved Communities
                c. Climate Justice for individuals and communities impacted by plant retirements or local pollution
                d. Impacts on Workforce (e.g., transition of workers from closing coal plants, exposure to weather, etc.)
            2. Costs associated with the development and deployment of all candidate resources
                a. Costs of Energy to Consumers
                b. Life Cycle Impacts
                    i. Pollution
                    ii. Greenhouse Gas emission
                    iii. Materials
                    iv. Utility disposal
            3. Improve Communication to the General Public
                a. PNM communications with public re: change in timing on demand, how that changes system needs, and smart meter data collection and security
                b. Not In My BackYard (NIMBY) attitude regarding siting polluting resources should be reversed and clean, job and tax base creating resources, should be sited in frontline communities as well.
3. **Identified Decision Points and Pathways**
    a. "Getting to Zero" Greenhouse Gas
        i. Motivations
            1. Regulations & Policy
                a. Energy Transition Act (2019)
                b. EPA's proposed greenhouse gas emissions standards for power plants
                c. N.M. methane control rules
            2. Public service in response to March 2023 IPCC report analysis summary for policymakers
            3. Recognition of Company's corporate commitment to zero carbon by 2040
    b. Making "no regrets" Decisions
        i. Evaluation of land use and community impact

ii. Broad Inclusion of Stakeholders
iii. Minimizing investment risk
    1. Avoiding and minimizing stranded assets
        a. Loss of public trust
iv. Maximizing Infrastructure Investment Opportunity
    1. First to market w/ long term solutions
    2. Public trust and sentiment
v. Value of money vs future human life opportunities

c. Evaluate & Pursue Regional Planning and Coordination
    i. Organized market opportunities
    ii. Future regional transmission operator (RTO) opportunities
d. Modernizing the Grid
    i. Policy needs to support reaching carbon targets, DSM (demand side management), DG (distributed generation) and other behind-the-meter resources)
    ii. Demonstrate transition from old to new grid structure
    iii. Assessment of impact of all areas of behind-the-meter resources.

4. Resources

a. Resource Description:
    i. A *brief* description of the resource; its technical characteristics.
b. Commercial Maturity:
    i. The Technology Readiness Level (TRL) or similar metric to describe the commercial maturity of the resource. How long has it been used in electric utility applications? This criteria needs to be done carefully. Some technologies have been the brunt of sabotage, business ineptness, and smear campaigns by the opponents.
c. Staged Cost:
    i. This is a breakdown of cost by scale (if applicable). For example, solar may have a cost for 1 MW to 5 MW; and a different cost for 10 MW to 100 MW. And for storage it should also include Return Trip Efficiency (TRE) and similar variables as are in the below table.
d. Grid Applications and Benefits:
    i. Why is this resource important to the grid? What are its applications and benefits?
e. Status of each resource in the modeling process (i.e., included, not included with reason why, not available for inclusion for lack of data, etc.)
f. Candidate Resources
    i. Base technologies
        1. Wind
        2. Solar
        3. 4-hr li-ion storage
        4. Energy efficiency
        5. Demand response
    ii. Other Resources
        1. Pumped hydro storage 70-hr (NW NM)
        2. Pumped hydro storage 8-hr (NW NM)
        3. Iron-air storage
        4. Compressed Air Energy Storage
        5. Liquified Air Energy Storage

6. Flow battery
7. Thermal storage (with steam turbine)
8. Combustion Turbines
9. Linear generators
10. Carbon capture retrofit (Afton)
11. NET power plant
12. Hydrogen

5. **Potential New Resources**
    a. Adoption of new technologies
    b. High Penetration of Distributed/Customer-owned Generation
    c. Energy efficiency and demand-response
    d. Cost-effective repowering or upgrading of existing fossil resources to minimize risk of stranded investment or delayed decarbonization
    e. Describe long duration storage options not considered (reference chart 1 in “Items for Discussion” below)
6. **[System Needs]**
7. **Preferred Portfolio - Refer to appendix of resource evaluation**
    a. [results of PNM modeling]
    b. Potential pilot projects
    c. [PNM conclusions]

Items for Future Discussion

"Parking Lot"

1. General
    a. Explanation of the Integrated Resource Plan (IRP)
        i. IRP as a tool for utility's capital outlay plan
        ii. Misconceptions about the 20-year IRP window
        iii. Importance of the 3-year Action Plan
2. Existing resources and technologies
    a. End-of-life considerations
        i. Definition and examples
        ii. Resource disposal post operational life
    b. Energy Resources to consider
        i. Geothermal energy
        ii. Small Modular Reactors (SMRs)
        iii. Issues and concerns with SMRs
    c. Issues with new gas as a resource
    d. Role of Energy Efficiency in IRP
        i. PNM's current portfolio
        ii. The role of IRP
        iii. Energy efficiency measures
    e. Role of Demand Response
    f. Role of Load Management
        i. Time of use rates and dynamic rate options
        ii. Importance of different load shifting scenarios
    g. Consideration for grid improvements for Demand-Side Management (DSM)
3. PNM's programs and their impact on DSM
    a. Whole House Electric Vehicle (WHEV) rate
    b. Implications for low-income customers with smart meters
    c. Electromagnetic wave generation concerns
4. Options for the transition from carbon-based energy
    a. Inclusion of all possible resources
    b. Prioritization based on feasibility, required infrastructure, reliability, and lifecycle costs - Comment by Robert Barber
5. Comments and Concerns from stakeholders
    a. NIMBY and consumer education
    b. Impact of electrification on load forecast
    c. Incorporating wind turbine capabilities into modeling
    d. Need for more information on distribution system planning
    e. Improved data collection on outages, especially in disadvantaged areas
6. Identified Decision Points and Pathways

a. Any impact from Methane?

OUTLINE EDITS

1. 2b3: Swift recovery from climate or security threats
2. Public service in response to March 2023 IPCC report analysis https://www.ipcc.ch/report/ar6/syr/ summary for policymakers - pg 23
3. Modernizing the Grid
4. 3e: Assessment of impact of all areas of behind-the-meter resources

1 There are numerous technologies within Long Duration Storage

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDED

Less Desirable → More Desirable

△ Faces geologic constraints[1] | Not enough public datapoints to obtain a reliable value | 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[1], %	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 CO2[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[4]	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[4]	XX	>100	55–75	4-9

1 Demand potential / market size is limited by the requirement for specific geological formations
2 Codified based on primary technology type
3 Can function as inter-day, but organized based on longest duration potential
4 Some flow batteries under development will not work for multi-day, but it is categorized here as such given the technology's maximum duration

U.S. DEPARTMENT OF ENERGY 4

Source: Adapted from LDES Council Net Zero Power Report 2021, Wood Mackenzie Long Duration Energy Storage Report 2022, Company websites, Academic research

Welcome!

Stakeholder Engagement Meeting
(Meeting #10)

2023-2043 Integrated Resource Plan, Public Service Company of New Mexico

Thursday, Oct. 19

9:00 AM – 11:00 AM Mountain Daylight Time

Note: this meeting is being recorded and will be available as public information. The link to the recording will be included in the meeting summary.

Materials available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

GRIDWORKS

Purpose and Outcomes of Today's Meeting

PURPOSE

Review Statement of Need (SoN) and Action Plan

KEY OUTCOMES

- Identification of areas of agreement and disagreement

Agenda

9:00 AM – Welcome, Purpose, Outcomes for the Meeting

9:05 AM – Review SoN (PNM team presents)

- Influences of Stakeholder Runs and Resiliency Study Results
- SoN Content Review

9:30 AM – SoN Discussion and Agreements

9:50 AM – Break

10:00 AM – Review Action Plan (PNM team presents)

10:20 AM – Action Plan Discussion and Agreements

10:50 AM – Summary of Actions and Meeting Feedback

11:00 AM – Adjourn

Influences of Additional Analyses

SoN Review

PNM TEAM

GRIDWORKS



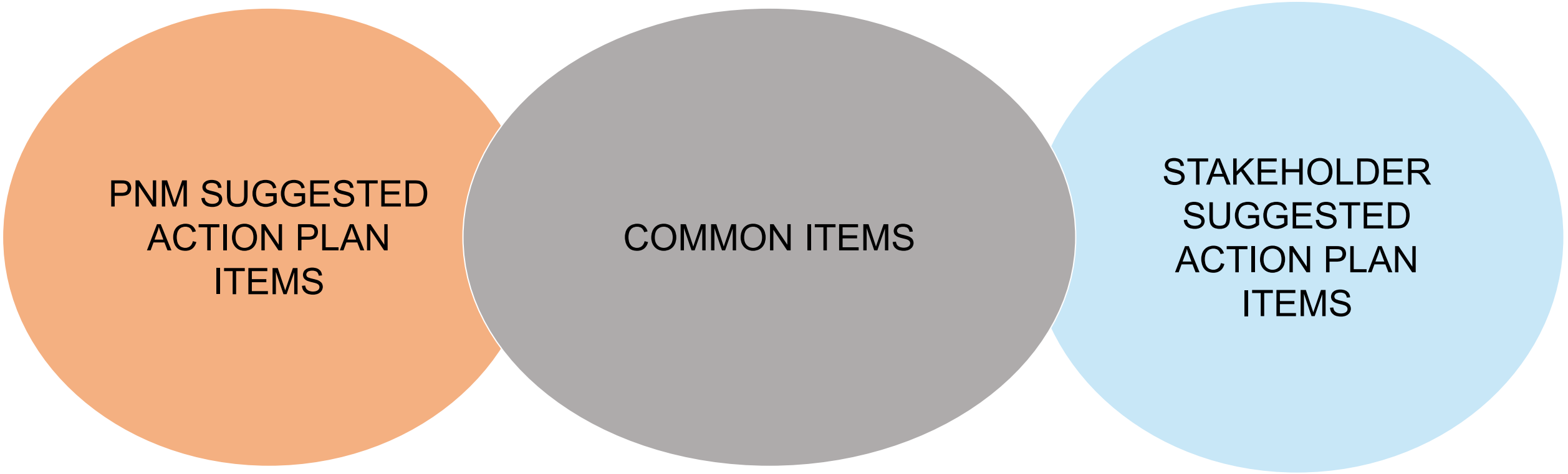
Do Stakeholders Agree with the PNM SoN?

Your views regarding capacity needs and resource types are critical.

If you have concerns or do not agree with the SoN, please speak up through one of two options:

- today, verbally or by chat, or
- by 12 NOON on Oct. 20 via email to info@gridworks.org

Framework for Action Plan Items



Action Plan Review

PNM TEAM

GRIDWORKS



Do Stakeholders Agree with the PNM Action Plan?

If you have concerns or do not agree with specific items in the action plan, please speak up through one of two options:

- today, verbally or by chat, or
- by 12 NOON on Oct. 20 via email to info@gridworks.org

Next Steps in the Process

Stakeholder Process

- Oct. 20: NOON, stakeholder comments on SoN and Action Plan emailed to INFO@Gridworks.org
- Comments welcome after Oct. 20 to IRP@pnm.com, copy to INFO@Gridworks.org
- TBD: Draft IRP available to stakeholders for information
- Dec. 19: 9 – 10:30 AM Meeting #11. Focus is feedback on stakeholder process.
- Jan. 31: Gridworks report delivered to the NM PRC.

IRP Process

- Dec. 15: PNM files the 2023 IRP
- 30 days after filing – written public comments filed (Jan. 15)
- 60 days after filing – PNM written response to public comments (Feb. 15)
- 90 days after filing – PRC Utility Division files statement regarding compliance of SoN and Action Plan with the IRP rule (Mar. 15)
- 120 days after filing – if the commission has not acted, the SoN and Action Plan are deemed compliant (Apr. 15)
- See the IRP rule for more details on RFP process.

GRIDWORKS

THERE WILL BE OTHER OPPORTUNITIES FOR STAKEHOLDERS TO ENGAGE IN FOLLOW-ON ACTIVITIES (ACTION PLAN ITEMS, RFP PROCESSES, ETC.)

Please Access and Complete the Survey Now

Feedback allows us to:

1. Measure effectiveness of this new process for the NM PRC
2. Improve Gridworks' facilitation effectiveness
3. Hear your concerns and suggestions

By either…

Scanning the QR Code to the right

OR

Visiting this link:
bit.ly/PNM-IRP-Feedback

Thank you for your engagement in this process.

Questions? Please contact Margie Tatro at:
mtatro@gridworks.org
505-205-0838

GRIDWORKS

Materials available at: New Mexico Energy Planning – Gridworks
or
https://gridworks.org/initiatives/new-mexico-energy-planning/

PNM 2023-2042 IRP: Modeling Results Update, Statement of Need, and Action Plan

FACILITATED STAKEHOLDER MEETING

OCTOBER 19, 2023



AGENDA

OCTOBER 19, 2023

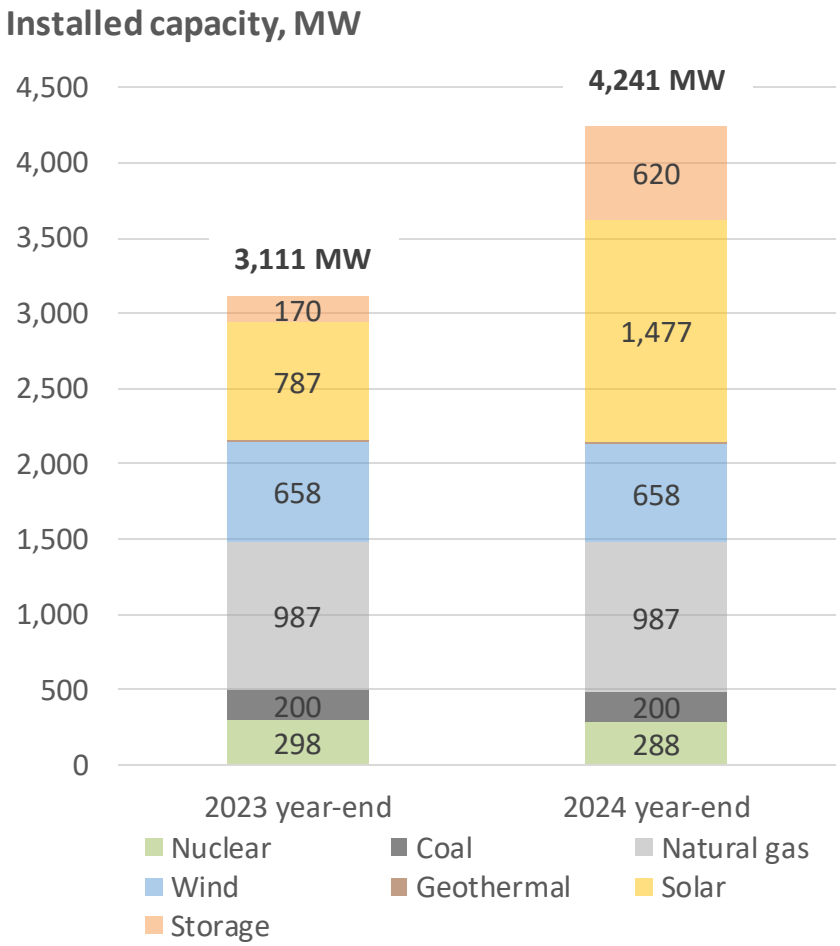
1. Stakeholder Capacity Expansion Results
2. Stakeholder Reliability Results
3. Phase 3 Resiliency Results
4. MCEP, Action Plan, and Statement of Need

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

PNM'S EXISTING RESOURCE PORTFOLIO AND NEAR-TERM RESOURCE ADEQUACY

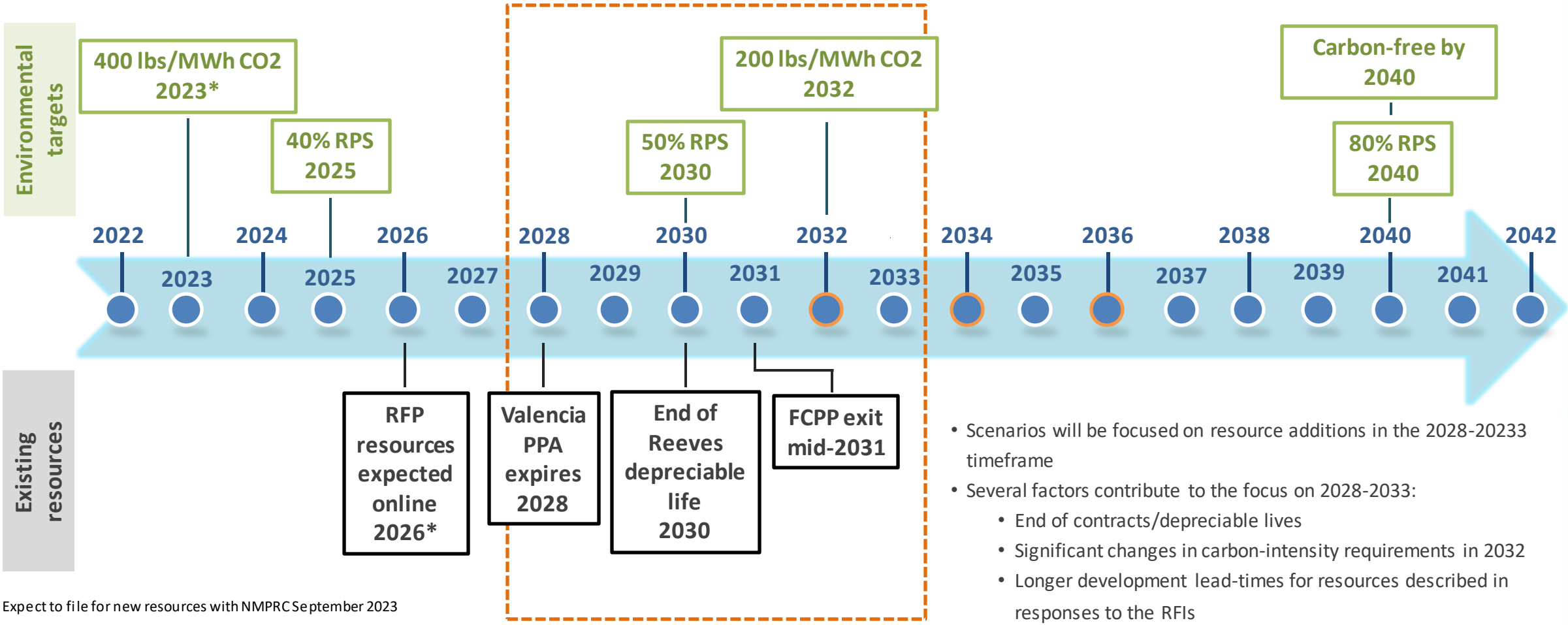


2024 capacity

- **Storage: 620**
- **Solar: 1,477**
- **Wind: 658**
- **Natural Gas: 987**
- **Coal:** 200 MW
- **Nuclear:** 288 MW share of Palo Verde

- Near term additions include 400 MW of solar and 170 MW of storage by the end of 2023
- By year-end 2024, PNM will have added an additional 690 MW of solar and 450 MW of storage
- RFPs for 2026-2028 are currently ongoing

KEY ELEMENTS WITHIN TIMELINE FOR 2023 IRP ANALYSIS POINT TO 2028-2033 AS A CRITICAL PERIOD



- Scenarios will be focused on resource additions in the 2028-20233 timeframe
- Several factors contribute to the focus on 2028-2033:
  - End of contracts/depreciable lives
  - Significant changes in carbon-intensity requirements in 2032
  - Longer development lead-times for resources described in responses to the RFIs

* Expect to file for new resources with NMPRC September 2023

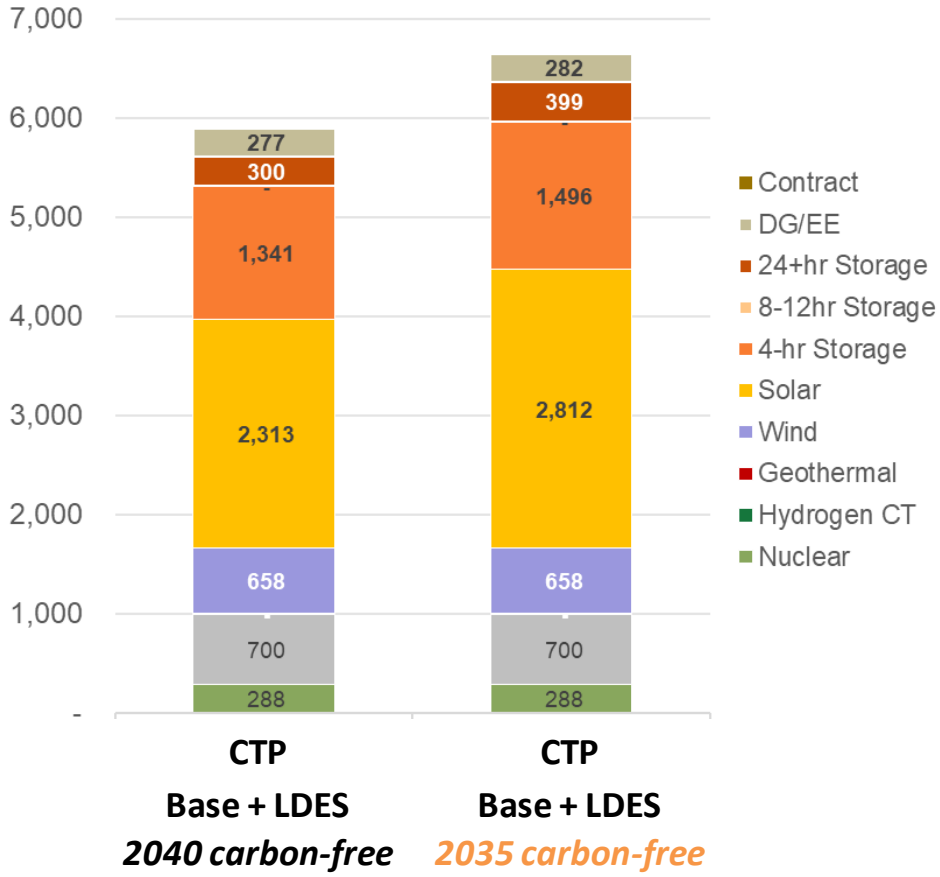
STAKEHOLDER SCENARIO RESULTS

*Carbon-free by 2035**

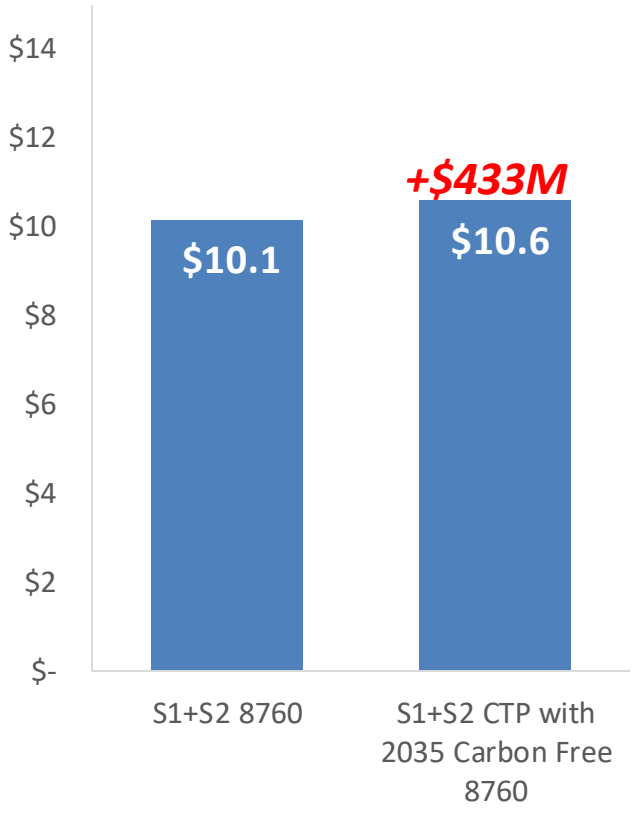
PNM Talk to us. PNM.com

2040 VS 2035 CARBON-FREE PORTFOLIO RESULTS UNDER CTP

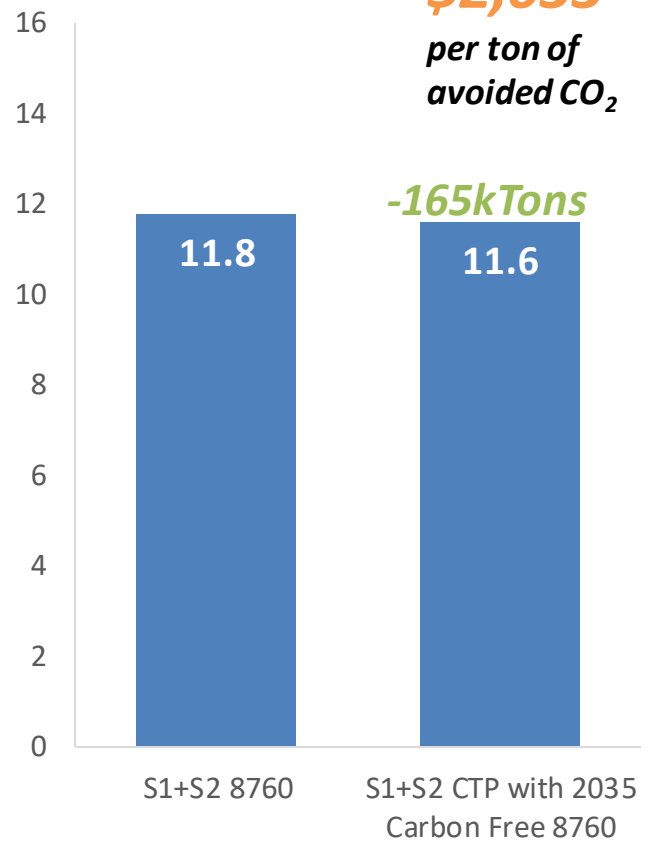
2032 Total Installed Capacity,
MW



Present Value Revenue Requirement,
$B



NPV Carbon Emissions,
MMT CO2



$2,633
per ton of avoided CO_2

-165kTons

PNM Talk to us. PNM.com

KEY TAKEAWAYS

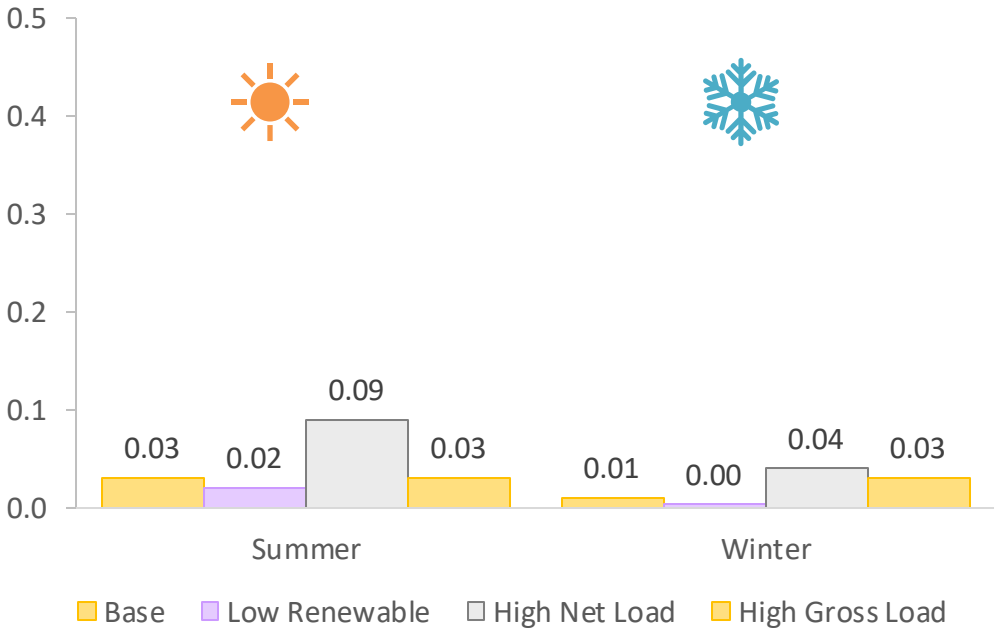
- To evaluate the benefits of achieving 2035 carbon-free vs 2040, we studied the effects under the **Current Trends & Policy (CTP)** case
- ***Achieving carbon-free by 2035 instead of 2040*** would increase costs by $433MM and decreases carbon emissions by 165kTons of CO_2
- ***This means avoiding CO2 at $2,633/ton,*** more than any estimate of the social cost of carbon.

STAKEHOLDER RELIABILTY STUDY RESULTS

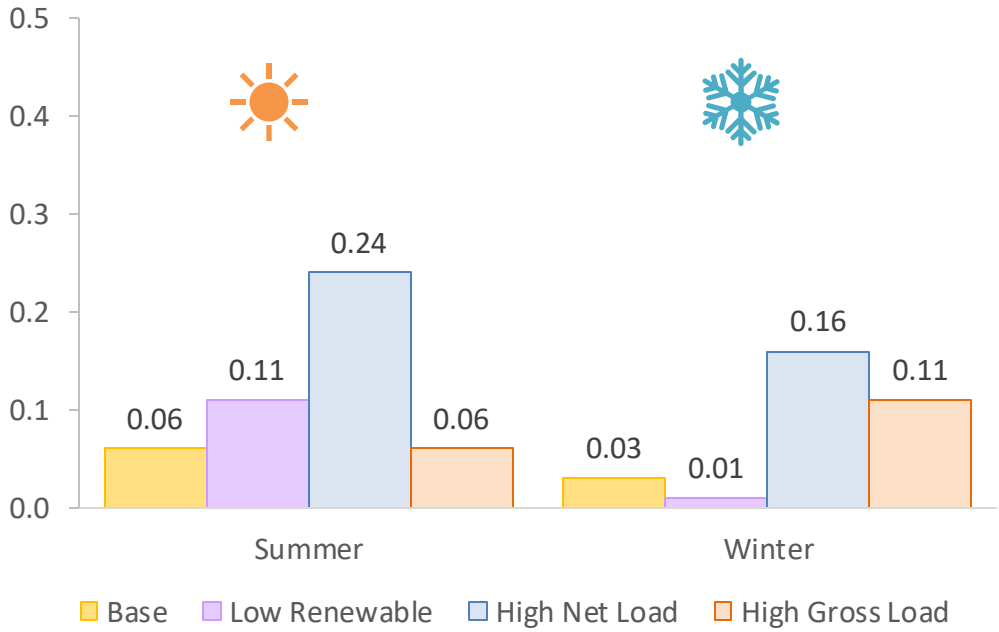
STAKEHOLDERS RELIABILITY SENSITIVITIES: EXTREME WEATHER IN RA (S1 CTP)

This sensitivity aims to quantify the risk associated with PNM's system under different weather scenarios

2032 loss of load expectation,
days per year



2040 loss of load expectation,
days per year



Base
Equal Weighting across all years

Low Renewables
weight 5 years with lowest seasonal renewable energy

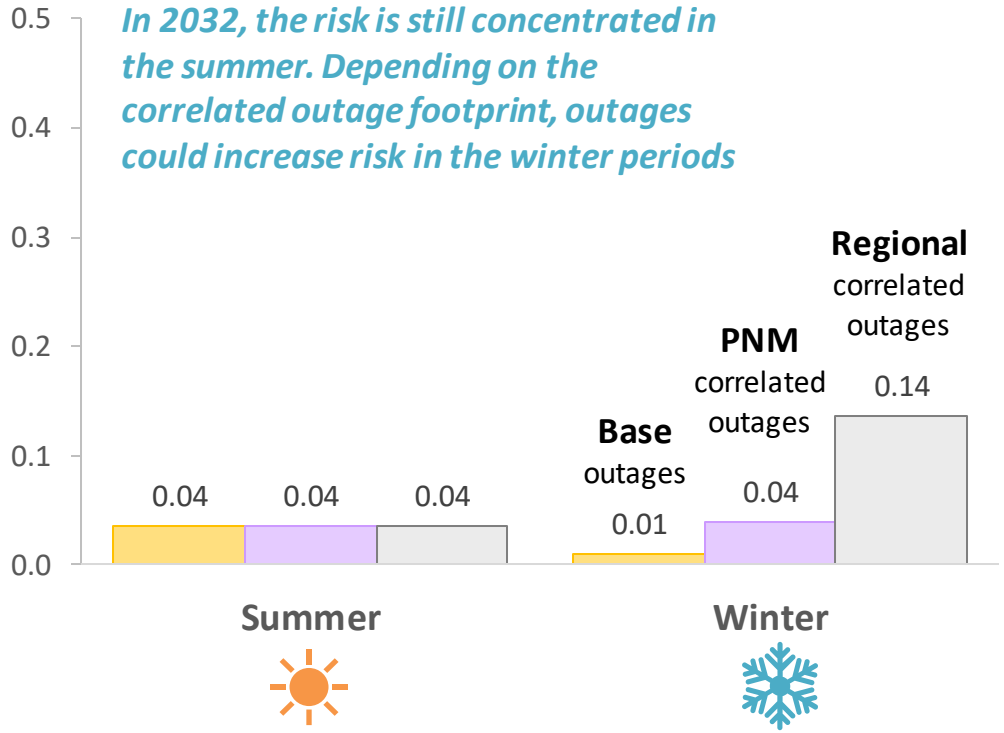
High Net Load
weight 5 years with highest seasonal net load

High Gross Load
weight 5 years with highest gross net load

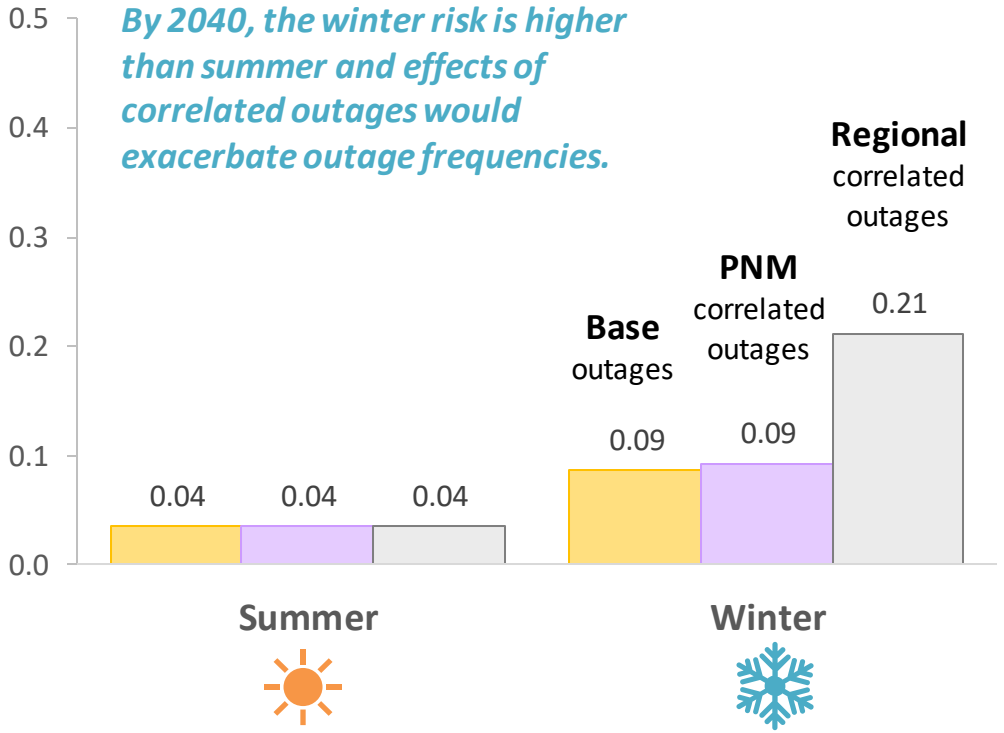
STAKEHOLDERS RELIABILITY SENSITIVITIES: CORRELATED OUTAGES (S3 CTP)

This sensitivity aims to quantify the risk associated with PNM's system under different correlated gas supply outage scenarios

2032 Summer vs Winter Loss of Load Expectation, *days per year*



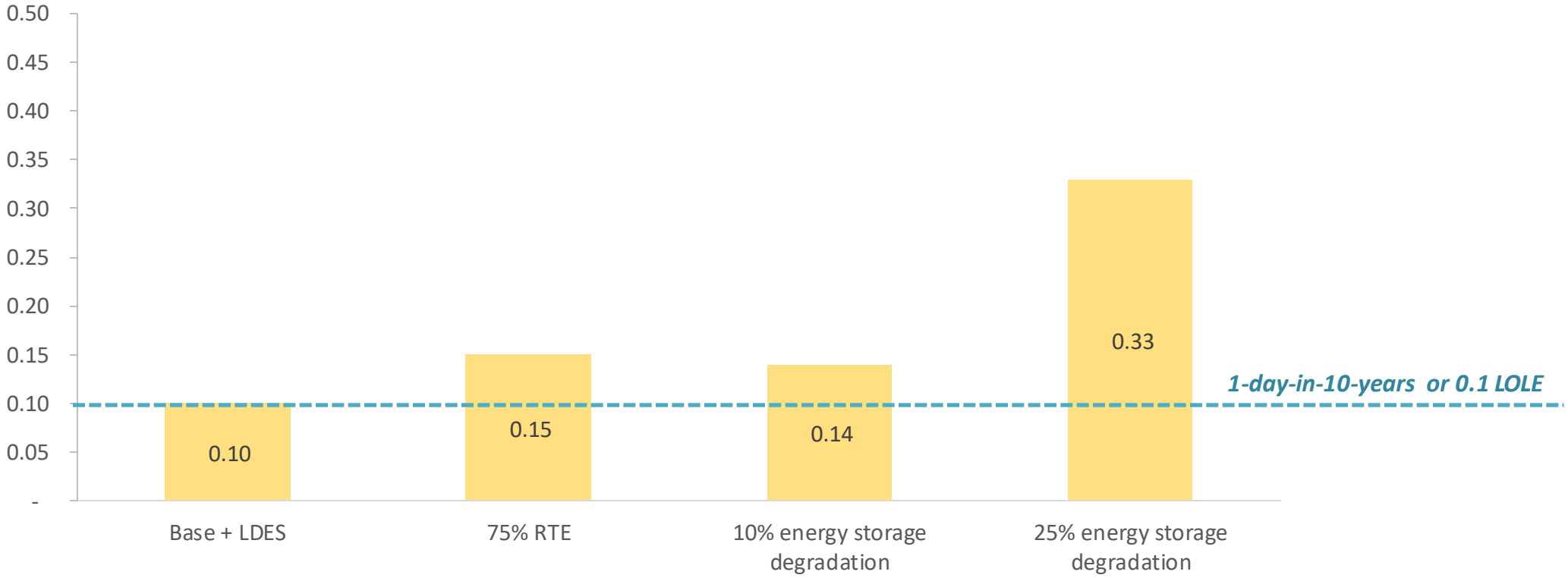
2040 Summer vs Winter Loss of Load Expectation, *days per year*



STAKEHOLDERS RELIABILITY SENSITIVITIES: BATTERY DEGRADATION SENSITIVITIES (S1)

By 2040, storage will make up a significant portion of our portfolio. This sensitivity aims to quantify the risks associated with battery degradation if PNM were not to augment storage capacity.

2040 loss of load expectation,
days per year



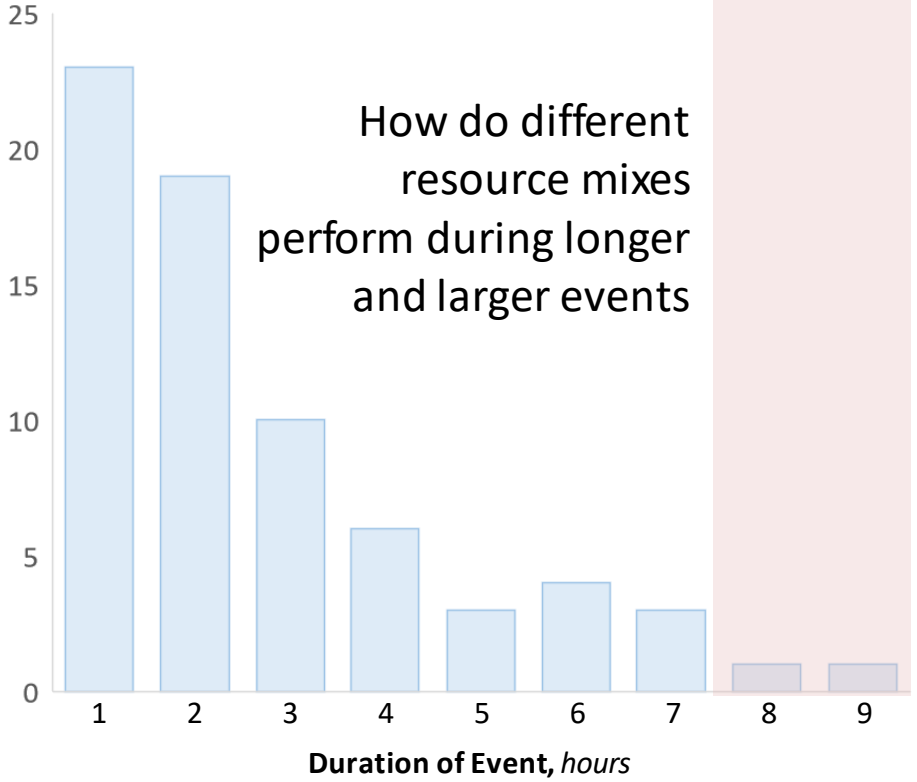
Talk to us.

PHASE 3 RESILIENCY STUDY RESULTS

RESILIENCE STUDY BACKGROUND

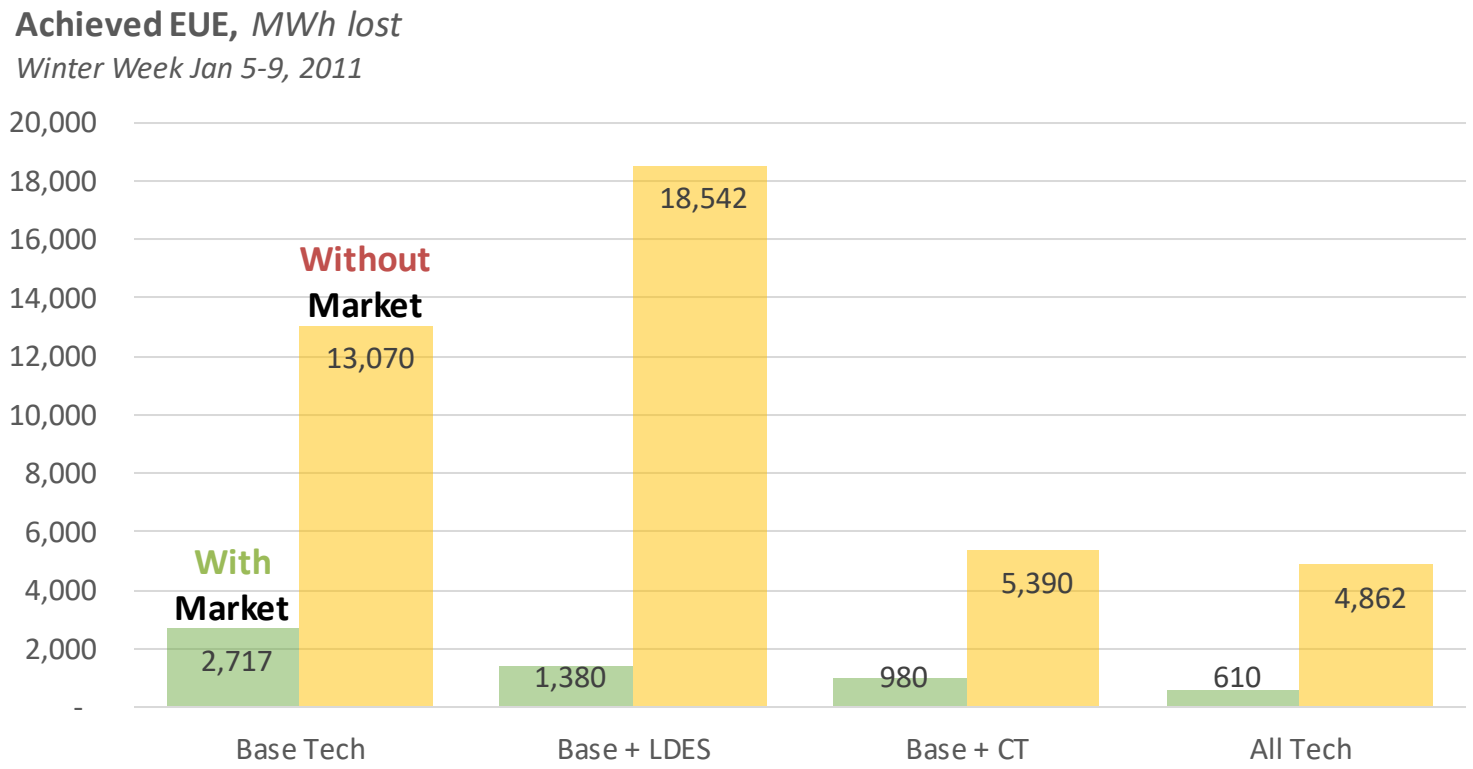
- Like our reliability study, this study examines each portfolio's reliability performance
- The difference here is the **focus on the portfolio performance during the extreme weather events**
- **General Steps to Analysis:**
  - Start with 0.1 LOLE
  - Tested summer and winter stress week
  - Calculated EUE across week
  - For scenarios that performed the worst, test incremental resources to meet the best performer
  - Calculate the incremental resource need and cost

Frequency of Loss of Load Events at Different Durations
2032 Base Technologies Scenario
(Count of number of events)



WINTER RESILIENCE STUDY RESULTS AND KEY TAKEAWAYS

- **Winter events are longer and larger than summer events**
  - Typically coincides during extended periods of high load and low renewable
- **Portfolio with firm generation are more resilient**
- **Future IRPs should further investigate LDES's resilience value**
- **Having access to the regional markets mitigates loss load events dramatically**
- **To normalize EUE between S1 & S3, S1 would need ~1,150 NMW of 4-Hr BESS additions**



PNM Talk to us. PNM.com

Statement of Need + Action Plan

STATEMENT OF NEED

- Established by rule of the New Mexico Public Regulation Commission (NMPRC), and in accordance with New Mexico Administrative Code (NMAC) 17.7.3.10
- *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.*
- *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,*
- *[The Statement of Need] 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.*



STATEMENT OF NEED

We'll now review the full Statement of Need document

ACTION PLAN

Governed by rule of the NMPRC, and in accordance with NMAC 17.7.3.11

The utility's action plan shall:

- *detail the specific actions the utility shall take to implement the IRP spanning a **three-year period** following the filing of the utility's IRP;*
- *detail the **specific actions** the utility shall take to develop any resource solicitations or contracting activities to **fulfill the statement of need** as accepted by the commission; and*
- *include a **status report** of the specific actions contained in the previous action plan.*



The utility shall update the commission by filing two reports describing the utility's implementation of the action plan. These reports shall be filed in the existing IRP docket one year after the filing of the IRP, and two years after the filing of the IRP, respectively.

An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.

The utility shall promptly notify the commission and participants of material events that would have the effect of changing the results of the utility's action plan had those events been recognized when the action plan was developed.

In accepting the action plan, the commission shall take into consideration contractual obligations as between the utility and any regional transmission organizations or balancing authorities of which the utility is a member.

ACTION PLAN

We'll now review the complete Action Plan

Appendix

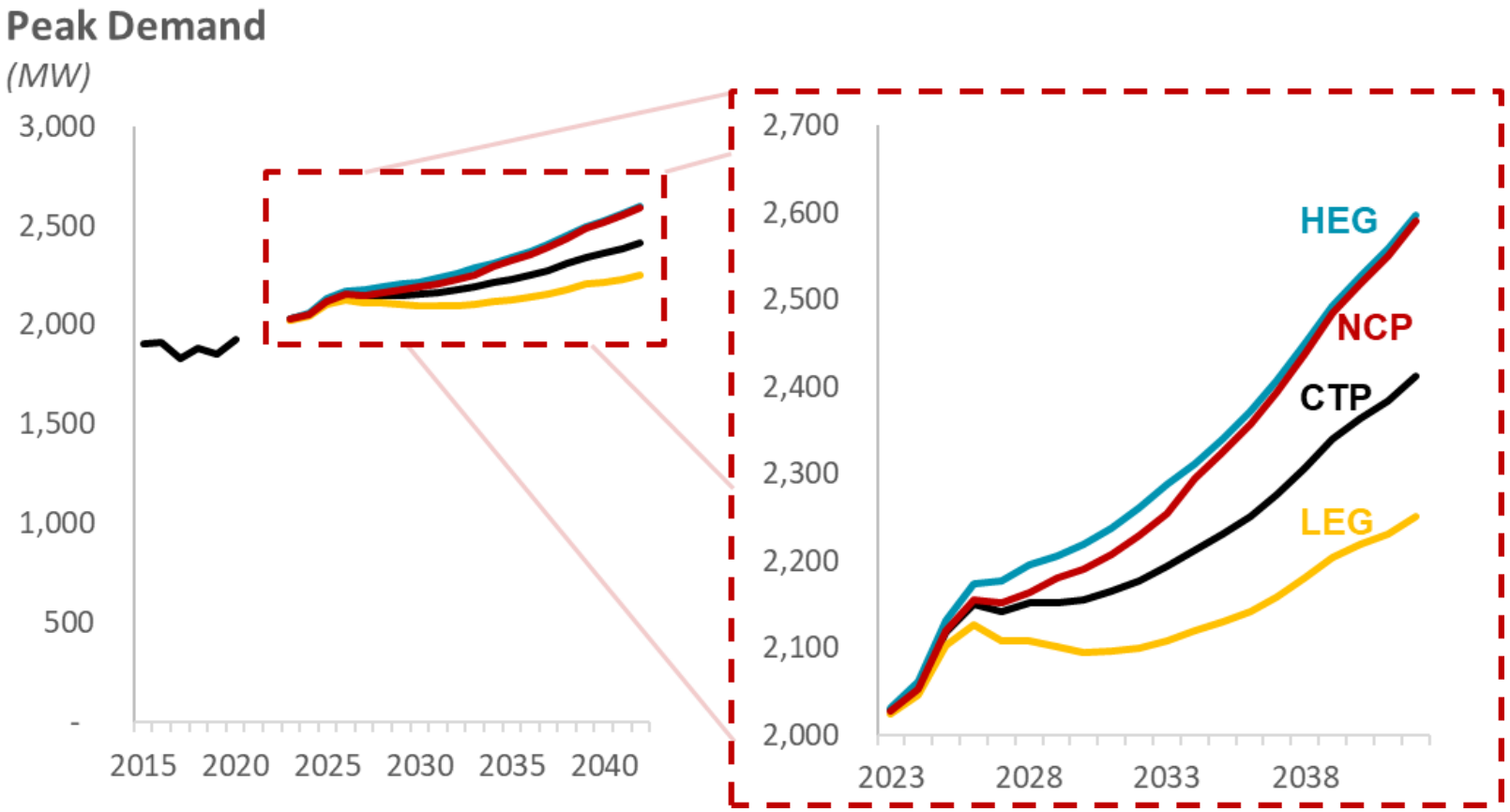
This table shows the inputs assumption differences between comparable Phase 3 scenarios to the carbon-free scenarios

ASSUMPTIONS SCENARIO COMPARISON: CARBON-FREE BY 2030 AND 2035

	Phase 3 Scenarios		Stakeholder Scenarios	
	S1+S2: Current Trends and Policy (CTP)	S1+S2: National Carbon Policy (NCP)	Carbon Free By 2035	Carbon Free By 2030
Scenario Comparison	Base Tech + LDES	Base Tech + LDES	Base Tech + LDES + Early Wind	Base Tech + LDES + Early Wind
Early Wind	No	No	Yes	Yes
By when does PNM achieve carbon-free?	2040	2035	2035	2030
Load Assumption	Mid + Limited Econ Growth	High + Stable Econ Forecast	High + Stable Econ Forecast	High + Stable Econ Forecast
Electrification	Mid	High BTM PV + EV + Building Elec	High BTM PV + EV + Building Elec	High BTM PV + EV + Building Elec
Carbon and Gas Price Forecast	Mid	High / High	High / High	High / High
Tech Cost Forecast	Mid	Low	Low	Low

COMMENT:
These 2 CO2 free stakeholder scenarios add up to 800 MW of wind prior to 2033 (which is the first year the CTP and S1+S2 NCP cases can begin adding)

LOAD GROWTH: CURRENT TRENDS & POLICY VS NATIONAL CARBON POLICY



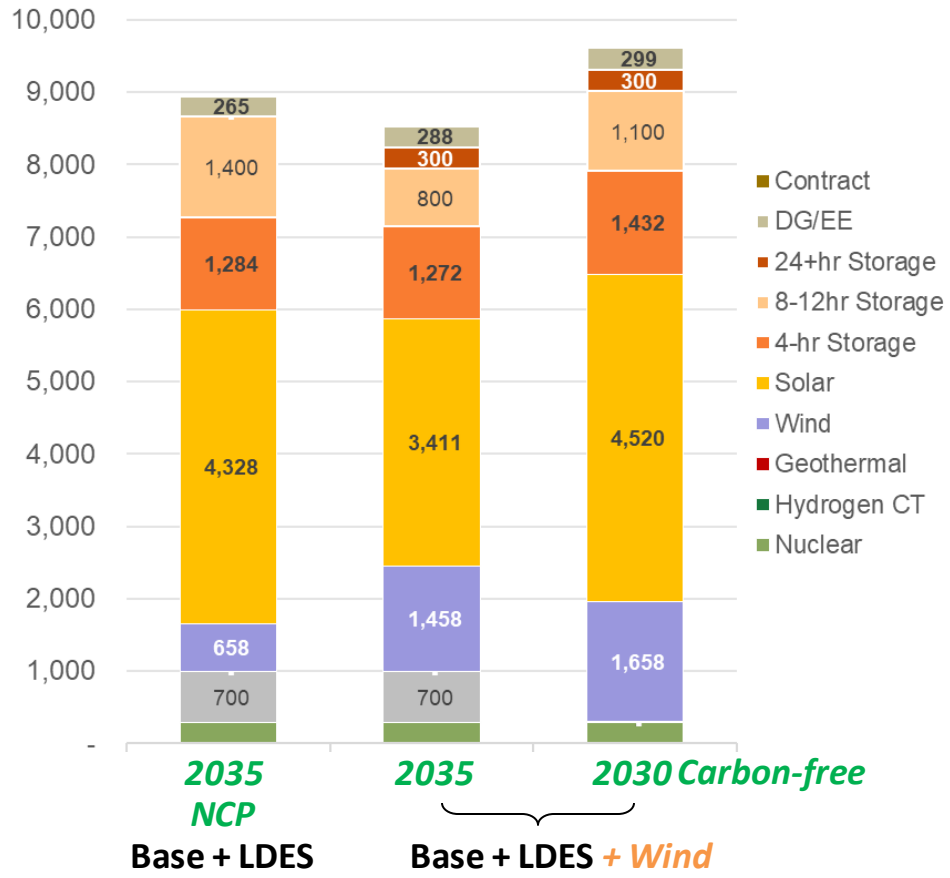
Between today and tomorrow, our peak demand is **expected** to grow from **~2,000MW to 2,400 MWs, or 20% growth**

If our system experiences **aggressive electrification and stable economic growth**, that peak demand could grow to **2,600MW, or 30% growth over 20 years**

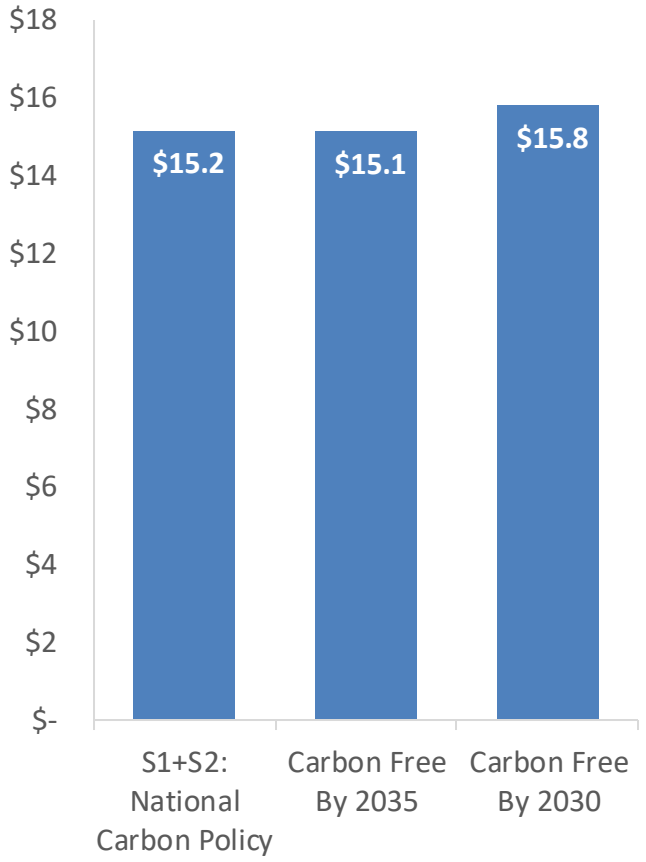
To meet this demand, we'll need to procure a mixture of low-cost carbon-free resources, dynamic balancing resources, and firm resources.

2040 VS 2035 VS 2030: CARBON-FREE PORTFOLIO RESULTS

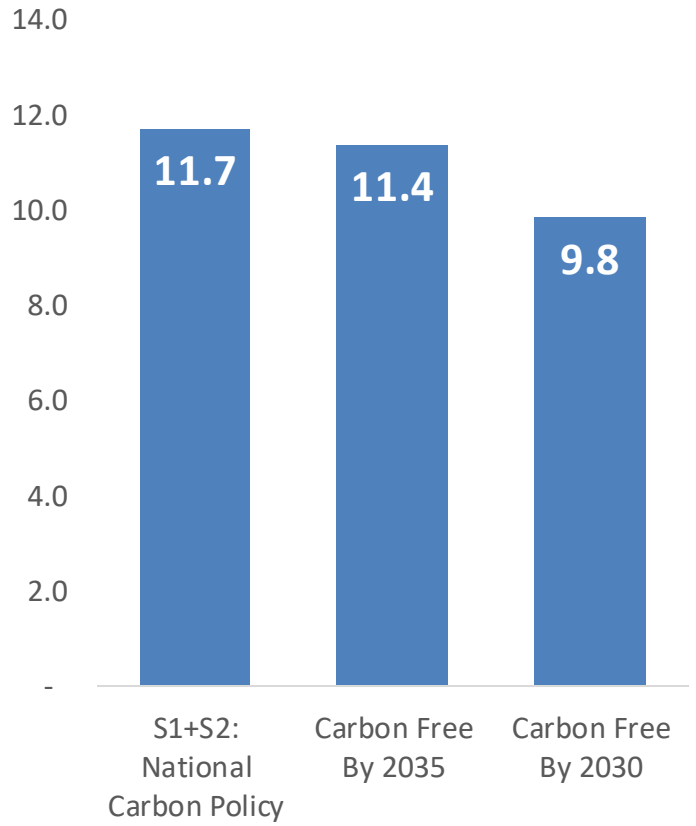
2032 Total Installed Capacity,
MW



Present Value of Rev Requirement,
$B

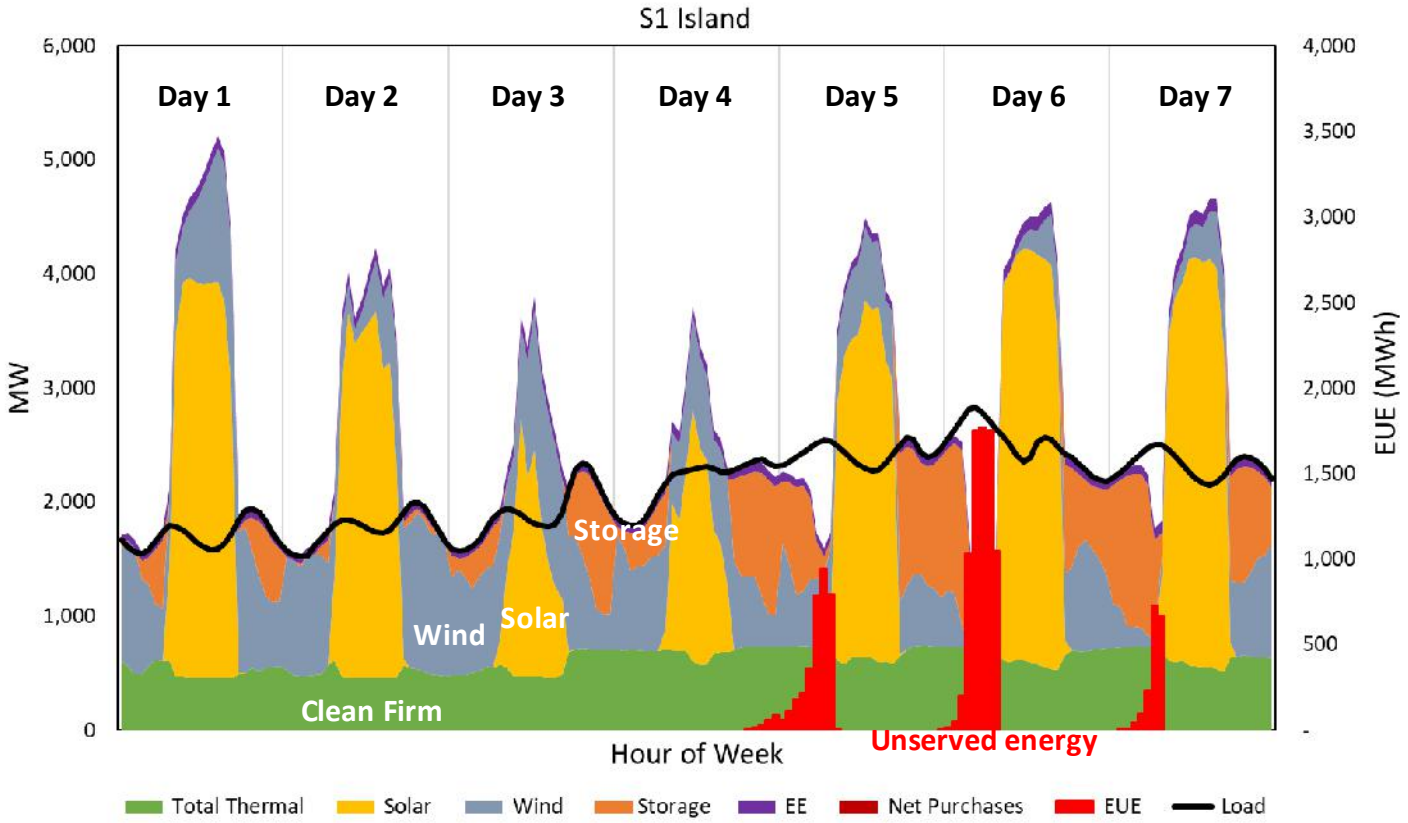


Present Value of Total CO2 Emissions
MMTCO2



PNM Talk to us. PNM.com

SCENARIO 1: BASE TECH ONLY - WHAT'S DRIVING THESE EVENTS?



Day 1 & 2: renewables and storage are more than capable of meeting all load

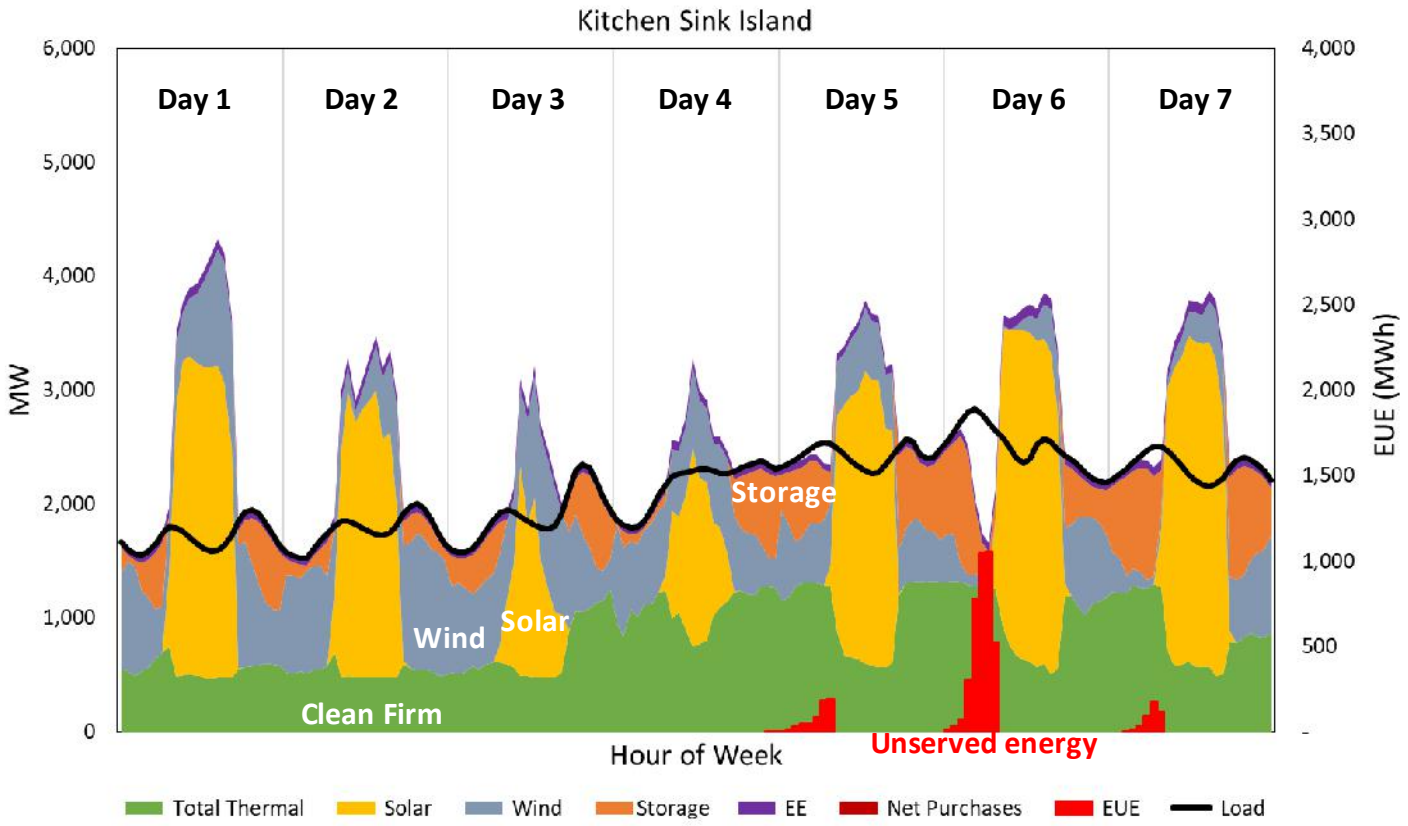
Day 3 & 4: consecutive low renewable generation day leads to reduction of storage charge, but no loss of load.

Day 5-7: sustained high demand and lack of renewable energy and storage leads to consecutive loss of load events

This Winter event experiences ***13,070 MWh***
Lack of energy leads to large short fall events renewables

PNM Talk to us. PNM.com

SCENARIO 3: ALL TECH - WHAT'S DRIVING THESE EVENTS?



Day 1-3: renewables and storage are more than capable of meeting all load

Day 4: Unlike Scenario 1, firm generation increases to meet morning and evening loads

Day 5-7: sustained high demand and lack of renewable energy and storage leads to consecutive loss of load events

This Winter event experiences ***4,860 MWh***

Lack of energy leads to large short fall events renewables

DRAFT

PNM IRP Statement of Need

2023-10-11

The PNM Integrated Resource Plan 2023 [IRP-2023] [provides/brings] the [best/furthest] long range path for building out a reliable generation portfolio for our customers over the next 20 years based on current planning assumptions and technologies. The IRP report begins with the current status of PNM's system and shows how available resources and technologies can provide for reliability and meet future needs. Simultaneously, we recognize that changes are occurring in every sector of the environment in which we operate. These will require ongoing re-evaluation and modifications to the 2023 IRP plan that will be incorporated in future triennial PNM IRPs.

Our planning framework balances three overarching objectives: maintaining reliability, minimizing cost, and mitigating our impact on the environment around us. We seek to create a long-term plan that achieves favorable results for our customers in all three areas:

- Reliability: our customers expect steady, reliable electric service. To meet this expectation, we plan our system to maintain a loss of load expectation of "one day in ten years," aligned with common industry standards; doing so requires us to plan our generation portfolio to meet customer demands all hours of the year, including under increasingly severe extreme weather conditions. As we plan to retire significant portions of our existing fossil generation portfolio over the planning horizon, we will need to add new resources that, together, can reliably supply our customers across all weather conditions.
- Affordability:
- Environmental Impact: PNM has established an ambitious goal to achieve a 100% carbon-free generation portfolio by 2040. As of 2022, our generation portfolio met 53% of our customers' total annual energy needs (10,000 GWh) with carbon-free electricity. Our plan must therefore include sufficient new carbon-free resources to displace the remaining fossil generation in our current portfolio and meet our future load growth – a total incremental need of 10,000 GWh of carbon-free energy by 2042.

Meeting the state and PNM's clean energy goals and preserving reliability while providing for the growing needs of our customers in an affordable manner will require significant amounts of new generation capacity over the next twenty years. We anticipate that over the seventeen years between today and 2042, the amount of new generation capacity installed is likely to exceed 6,000 MW. This amount of *new* capacity is almost twice as much as exists in our system today, implying that the achievement of our goals will require a sustained, concerted effort to transform our portfolio.

The types of resources that we expect procure to meet those needs 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 our customers' energy needs throughout the year. Examples available today include solar PV, wind, and energy efficiency.

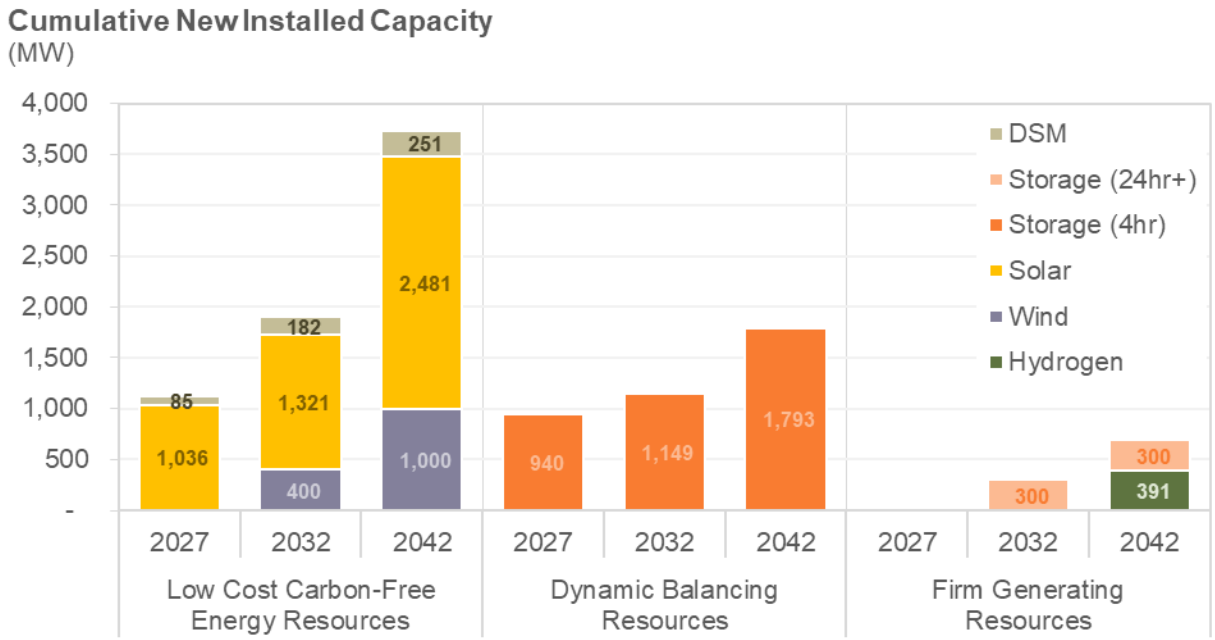
- **Dynamic balancing resources** that enable our operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of our carbon-free resources will not coincide naturally with electricity demand. Examples include shorter-duration 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 our 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 our nuclear and fossil resources; in the future various emerging technologies including hydrogen and long-duration storage may help to satisfy these needs.

Based on what we know today and our expectations for the future, our Most Cost-Effective Portfolio reflects our current vision of the resources that would best fulfill these needs. Figure 1 summarizes the new resource needs in the MCEP at three key milestones: 2027, at the end of our Action Plan; 2032, after our exit from Four Corners and the retirement of Reeves; and 2042, at the end of our planning horizon.

- In the near term, we plan to meet most of our needs with a combination of solar and battery storage resources, most of which are already under development or will be procured through active solicitations.
- In the medium term, our resource needs grow due to load growth and plant retirements, and our MCEP includes a total of nearly 1,900 MW of low-cost, carbon-free energy resources, 1,200 MW of dynamic balancing resources, and 300 MW of firm generation resources.
- In the long term, our MCEP includes over 3,500 MW of low-cost carbon-free resources, 1,800 MW of balancing resources, and 700 MW of new firm generating resources.

DRAFT

Figure 1. Summary of future resource needs in our Most Cost-Effective Portfolio



While our MCEP reflects our current view of the most cost-effective viable pathway to our carbon-free goal in 2040, there are a multitude of uncertainties that may change the composition of the portfolio that best meets the combined goals of our planning processes. By studying a diverse range of scenarios in this IRP, we intend to equip our planners and stakeholders with information needed to understand the full range of options and the factors that might lead us to change course from our current MCEP. Across all viable pathways to our 2040 goal and the numerous futures and sensitivities that we studied, the range of plausible resource needs is indeed broader:

Table 1. Ranges of new capacity additions across the planning period (OPTION 1: include Base Tech)

	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	1,600 - 1,900	3,600 - 4,200
Dynamic balancing resources	1,100 - 1,200	1,200 - 1,900	1,800 - 4,300
Firm generating resources	0 - 100	0 - 300	0 - 700
All resources	**2,300**	**3,300 - 3,600**	**6,300 - 8,600**

DRAFT

Table 1. Ranges of new capacity additions across the planning period (OPTION 2: exclude Base Tech)

	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	1,600 - 1,900	3,600 - 4,000
Dynamic balancing resources	1,100 - 1,200	1,200 - 1,500	1,800 - 2,300
Firm generating resources	0 - 100	100 - 300	500 - 700
All resources	**2,300**	**3,300 - 3,400**	**6,300 - 6,900**

Ultimately, the specific portfolio of resources that best meets the needs of our customers and achieves our goals will be determined by a combination of market forces, technological advances, and industry trends that cannot be perfectly predicted today. This taxonomy and the ranges associated with each category nonetheless provide a useful indication of the scale and nature of our future resource needs.

As a first step towards this end point, our Action Plan comprises the following steps over the next three years:

1. **Issue an all-source RFP for resources coming online 2029–2031 time periods**
   - Include environmental justice factors in the bid evaluation process;
   - Include system reliability and resiliency assessments, fuel security, and resource diversity in the bid evaluation process;
   - Utilize an independent evaluator as part of the RFP process;
   - File for resource approvals with the NMPRC (PPA/CCN), balancing resource selections between utility owned and third-party contracts; and
   - Maximize IRA funding, as available, to the extent practical in alignment with system resource timing needs.

2. **Issue an RFI/RFP for long-lead time resources or newer technologies that could deliver between 2029-2035**
   - Include environmental justice factors in the bid evaluation process;
   - 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; and
   - Leverage programs available under the IRA to access affordable, carbon-free resources.

3. **Evaluate abandon of 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;
   - 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
   - Leverage IRA programs, like the “energy community” bonus, to maximize benefits, mitigate financial costs, and promote environmental justice.

4. **Transition Resource Adequacy modeling to incorporate 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, associated resource adequacy modeling should be incorporated into PPA and/or CNN filings prior to filing the 2026 IRP.

5. **Establish a stakeholder modeling workshop (or series of workshops) that will kick off no later than 9/15/2024 to inform modeling assumptions and protocols that will be utilized in the 2026 IRP.**
   - Discuss concepts and have PNM test those concepts, if possible, to inform the group’s recommendations;

- Demonstrate loss of load expectations under situations, like correlated gas outages and battery storage degradation, to inform resource modeling; and
- Promulgate significant findings to help public stay informed about relevant insights

6. **Evaluate the ability to create new demand response and other customer programs, including customer sited storage, interruptible rates, etc. and request regulatory approvals as necessary.**
   - Continue to develop and implement cost effective energy efficiency and demand side management programs and file plans with the Commission as applicable;
   - Explore cost-effective options to maintain system supply and reliability;
   - Continue to explore, develop, market, promote, and seek approval of dynamic pricing structures (e.g., TOD) to empower ratepayers and encourage energy usage that minimizes usage during peak system risk periods;.
   - Continue advancing grid modernization efforts, including AMI conversion, to support new customer programs in the future; and
   - Consider new DR programs, including flexible requirements, with the goal of improving program performance during peak risk periods.

7. **Assess the ability add capacity at PNM's existing plant sites**
   - Inventory existing sites, identifying:
     - greatest expansion potential, considering utilization of supporting resources (land, water, staff, etc.);
     - most desirable with respect to available transmission capacity; and,
     - nearest to existing or developing load centers.
   - Consider supplementary resources (e.g., modular generators or storage) that could be used to add capacity to existing sites;
   - Determine which sites, if any, may be conducive for retrofitting existing infrastructure to increase capacity; and
   - Identify constraining assets (e.g., substation transformers, cooling systems, operating permits, etc.) that may reduce headroom or restrict capacity additions

8. **Continue to explore the ability to participate in regional markets**
   - To the extent that it is under PNM's control, encourage dialogue with regional partners to advance regional coordination and cooperation
   - Communicate with neighboring utilities and participate in planning activities to help determine options, risks, benefits, and ultimately, the best path forward for PNM;
   - Monitor regional attributes like resource liquidity, especially during times of severe local weather; understand market value and trends; and
   - Assess benefits of regional market participation, as it relates to extreme weather;
9. **Assess the need to utilize other reliability metrics in planning**

- Evaluate whether the industry standard of 0.1 loss of load expectation (LOLE) per year remains best practice for resource adequacy planning;
- Assess whether additional metrics should be utilized in resource adequacy planning and/or how resiliency metrics should be established and considered in planning; and
- Continue grid modernization activities, including AMI deployment, to improve visibility into system outages at the distribution level.

10. **Conduct the 2026 IRP**
    - Address the implications of the expiration of supply contracts and any retiring resources (e.g., Valencia, Reeves and Red Mesa);
    - Work with stakeholders in an ongoing collaborative public advisory process, including communication of electricity sector changes and the IRP process

11. **Create pilot programs to explore new technologies**
    - Explore opportunities for federal and state funding, as available

12. **Investigate improvements to IRP process to potentially incorporate integrated transmission and eventually distribution system planning**
    - Understand internal constraints and other considerations against which improvements must be weighed and balanced;
    - Review initiatives undertaken by peer utilities to migrate from a standard Integrated Resource Planning (IRP) framework to a more holistic Integrated Systems Planning (ISP) process; cultivate lessons learned, general roadmap, and real or anticipated benefits;
    - Discuss the potential benefits and trade-offs with stakeholders through the 2026 IRP process and gain feedback from Stakeholders during the modeling workshops outlined in Action Plan item 5.

13. **Continue to assess and pursue system needs for economic development in New Mexico, including issuing RFPs for timely resource additions as necessary**.

14. **Achieve Renewable Energy Standard goals as well as the ETA carbon intensity standards including necessary resource changes or additions, including issuing RFPs as necessary for timely compliance.**

Action Plan Mapping

Stakeholder Input	Corresponding Section	Comments
Changing fossil fuel plants to long duration energy storage as environmental justice for impacted communities	1, 2, & 3	We concur with the intent of comment and while ability to change or add technologies at existing fossil fueled power production sites is dependent upon NMPRC approvals, PNM does believe that EJ factors should be considered in the RFP bid evaluation process and PNM will work with stakeholders to propose resources consistent with that process.
Collect distribution feeder level reliability metrics to understand reliability equity	9	Reliability at the feeder level is not a question of resource adequacy, but rather a function of investment in the distribution system, effectiveness of maintenance and repairs, as well as environmental conditions like wildlife interference or exposure to harsh weather conditions. These considerations are fundamentally important to PNM, but are not related to the IRP; therefore, they will be addressed in another forum.
Initiate public information effort regarding electricity sector changes and IRP process	5, 10	Communicating with customers and other stakeholders is an important function of PNM's commitment to transparency and engagement. Public participation in this IRP process has been robust and productive; we intend to continue promulgating information and soliciting feedback as part of the 2026 IRP. PNM is willing to make outreach and education commitments as a part of the action plan provided PNM and stakeholders can reach agreement on how this would occur, PNM's role, etc.

Explore availability of landfill gas as supplementary/replacement fuel	1, 2, 5, & 11	PNM is committed to a competitive process that examines all viable options for the benefit of its customers. With this in mind, resource opportunities sourcing landfill gas as a primary or supplementary fuel source would be eligible and welcome to respond to the all-source solicitation and PNM will continue to explore these opportunities in future planning processes.
Include extreme weather considerations during next IRP cycle	5	Extreme weather is inherently built into our strategy for diversified resource portfolios and the associated load forecasts and resource modeling that is performed for the IRP process. We recognize that extreme weather is having a greater impact on our reliability planning, including scenarios that stress both electrical supply and demand. PNM is committed to receiving input from stakeholders on areas of focus in the next planning cycle.
Explore benefits from participation in organized regional market, and from participation under extreme weather scenarios	8	PNM concurs with this comment. The IRP addresses benefits of participation in regional markets to manage resources, risks, and costs.
Incorporate consideration of correlated gas outages in next IRP cycle	5	As demonstrated in other parts of the country over the past several years, correlated outages can happen. Early analysis of loss of load expectation (LOLE) indicates that correlated outages represent a manageable risk that is aligned with reliability expectations prescribed by the IRP. PNM is committed to receiving input from stakeholders on areas of focus in the next planning cycle.
By 2026, PNM shall have a default time of day rate for all customer classes. PNM shall assess the success of the time of day pilot and develop a plan to enroll all customers on a time-varying rate.	N/A	While PNM fully intends to pursue time-of-day (TOD) pricing as a mechanism of empowering customers to control their electric bills and mitigate peak demand, this is not under the control of the IRP and cannot be included in the associated IRP Action Plan. Implementing a new rate or rate class requires approval of the NMPRC. PNM invites feedback related to pricing through its Pricing Advisory Committee (PRAC).
Achieve demand response impacts of 5% of peak demand by 2026. PNM currently achieves demand response reduction of approximately 3% of peak demand. To reach this goal, PNM should solicit new DR programs with flexible requirements. This new solicitation should go out by mid-2024.	1,6	PNM believes that DR and all DSM is an important aspect of decarbonization strategy overall and aligns with Action Plan item 6; however, rather than prescribe specific amounts of resource additions, demand response should compete againt other resources in a competitive process. The All-Source RFP contemplated in Action Plan item 1 will invite both demand side and supply side technologies to meet future resource needs. .

Develop a list of advanced geothermal developers and ensure they are contacted for future RFI's. Develop a relationship with the advanced geothermal development community in the state	1 & 2	PNM is committed to a competitive process that examines all viable options for the benefit of its customers. However, it would be inappropriate for PNM to single out a specific technology and provide an advantage not given to other technologies.
Work to solicit geothermal bids and bids for a variety of thermal storage technologies.	1 & 2	PNM is committed to a competitive process that examines all viable options for the benefit of its customers. However, it would be inappropriate for PNM to single out a specific technology and provide an advantage not given to other technologies.
Pumped Storage Hydro, CAES and long duration batteries are not currently realistic options. The following technologies are those that seem to be realistically available to PNM: Wind, PV, Li-ion (up to 4 hours economical); CT's; 8 hour pumped hydro. Converge on desired resource characteristics through the IRP process (rather than an IRP that includes potentially non-viable and speculative technologies), and then put out another RFI for narrowing to alternatives that are viable for inclusion in a future RFP and/or bilateral procurement where warranted.	2	This comment is more appropriately considered in the comment and feedback period for RFP instructions to bidders contemplated in NMAC 17.7.3.12
Hold a 2026 RFP for resources that will come online 2029 and beyond.	1	PNM concurs with this comment and believes it is fully addressed in the 2023 IRP Action Plan item 1.
Actively engage with evaluation activity for the most promising, maturing carbon free technologies like thermal or iron-oxide storage	2,11	PNM is committed to a competitive process that examines all viable options for the benefit of its customers. However, it would be inappropriate for PNM to single out a specific technology and provide an advantage not given to other technologies.
Share transmission assumptions with stakeholders and allow developers to give feedback and least-cost site projects.	12	PNM values insight and feedback from stakeholders to identify least-cost projects. Further, we recognize the importance of integrating transmission planning with our resource planning to ensure that the best, least-cost resources are accessible and that we account for associated transmission needs. However, PNM will not make transmission models, including assumptions, available to third parties. Due to the sensitive nature of critical energy

		infrastructure information (CEII), and PNM's interest in upholding a fair and competitive procurement process, information of this nature is best acquired through a formal CEII request with FERC and WECC. PNM will continue to explore the best way to further integrate transmission modeling into the IRP for planning its retail system.
Prioritize projects and resources that can locate in federally designated energy communities (supported by the Inflation Reduction Act) and deliver low-cost clean energy to while providing economic development in communities that are transitioning from a carbon-based economy.	1	PNM is enthusiastic about the opportunities available through the Inflation Reduction Act (IRA). We believe the financial benefits will help PNM to accelerate its transition to carbon-free portfolio while maintaining affordable costs for its customers. Due to the timing of the IRA, and competing priorities within the IRP, we are not inclined to make an explicit commitment in the IRP Action Plan; however, we intend to take full advantage of IRA programs, particularly in our energy communities, where these programs can be leveraged to even greater benefit. We intend to issue an all-source RFP that will attract multiple responses to produce a highly competitive process; subsequently, we may favor specific, desirable resource attributes through scoring factors.
Upgrade models and software so PNM can model 8760 hours during the capacity expansion phase. Due to software limitations, storage is not modeled holistically in PNM's IRP process	5	Changing our modeling software has repercussions that have not been fully assessed; therefore, we are not inclined to make this commitment in our IRP Action Plan. However, the comment has merit and may be considered separately. We further believe this is the type of discussion that could have merit in the modeling workshop(s) contemplated in Action Plan item5.
Refine modeling parameters including forced outage rates and chemical degradation over time for BESS resources	5	PNM is committed to receiving input from stakeholders on areas of focus in the next planning cycle. Unfortunately, formally incorporating every possible parameter into resource modeling would make the process untenable.
Include future PPA procurement in the modeling process in addition to the assumption that PNM will own new resources	1&2	The resource procurement method is not specified in the IRP (that is the IRP does not differentiate between ownership structures, this is determined in RFP processes which will continue to allow third party and utility owned bids).
Improve financial modeling so it accurately represents the cost difference between a 60-year lifetime resource and a 20-year lifetime resource	5	PNM is committed to receiving input from stakeholders on areas of focus in the next planning cycle.

Use a better transmission model. The current "ball and spoke" model is insufficient to the need for planning in the state	5&12	Changing our modeling software has repercussions that have not been fully assessed; therefore, we are not inclined to make this commitment in our IRP Action Plan. However, the comment has merit and may be considered separately. We further believe this is the type of discussion that could have merit in the modeling workshop(s) contemplated in Action Plan item5..
Establish a stakeholder modeling workshop (or series of workshops) that will kickoff no later than 9/15/2024 to inform modeling assumptions and protocols that will be utilized in the 2026 IRP.	5	PNM concurs with this comment and has incorporated it into the Action Plan.
Transition Resource Adequacy modeling to incorporate WRAP forward showing planning requirements and resource attributes no later than PNM's 2026 IRP.	4	PNM concurs with this comment and has incorporated it into the Action Plan.
Any assessment to add capacity to a PNM plant site should also commit to include surrounding sites that could potentially interconnect to the point of interconnection (surplus interconnection service) with a technology that does not fit within the current site footprint	N/A	PNM is not able to integrate this into its Action Plan. FERC provides resources for standard large generator interconnection agreements (LGIA), which define a formal path for interconnection. This policy has already been contemplated in early iterations of the current IRP rule and ultimately dismissed. The Open area transmission tariff (OATT) allows interested parties to submit applications and enter the queue through standard channels.
PNM should commit to attempt maximizing federal dollars coming into the state for the benefit of energy communities while balancing cost and reliability	N/A	We are generally in agreement with this comment though this is more related to procurement as opposed to IRP and as such this comment is better addressed through the RFP commentary period contemplated in 17.7.3.12. PNM is enthusiastic about the opportunities available through the Inflation Reduction Act (IRA). We believe the financial benefits will help PNM to accelerate its transition to carbon-free portfolio while maintaining affordable costs for its customers. We intend to take full advantage of IRA programs to the greatest extent possible while complying with overall procurement rules, particularly in our energy communities, where these programs can be leveraged to even greater benefit. (not a readily capable action for compliance)
Long lead time resources should be defined as those with construction and permitting timelines greater than six years, rather than reference a specific resource type. This includes pumped storage and transmission, as well as	1	We appreciate this comment; however, the appropriate mechanism to address specific types, terms, or other definitions related to resources is in the instructions to bidder section of a request for proposals (RFP) Section 17.7.3.12 of the IRP rule states that instructions to bidders will be offered to comment in the IRP docket prior to issuing the RFP,

technologies that are being built on a large scale and do not fit within the normal RFP or action plan timeline		
PNM should commit to having a transparent transmission modeling process that allows the public and interest groups to engage with modeling assumptions. Some aspects of this transparency might require the signing of confidentiality agreements to comply with federal regulations and laws, but those will not be unreasonably withheld from the public.	5	PNM values insight and feedback from stakeholders to identify least-cost projects. Further, we recognize the importance of integrating transmission planning with our resource planning to ensure that the best, least-cost resources are accessible and that we account for associated transmission needs. However, PNM will not make transmission models, including assumptions, available to third parties. Due to the sensitive nature of critical energy infrastructure information (CEII), and PNM's interest in upholding a fair and competitive procurement process, information of this nature is best acquired through a formal CEII request with FERC and WECC. PNM will continue to explore the best way to further integrate transmission modeling into the IRP for planning its retail system.
Commit to utilizing a new transmission model in the next IRP that is either internally developed or contract an improved model and/or software that can utilize the underlying transmission model to select "best path" transmission assets in resource planning.	5	Changing our modeling software has repercussions that have not been fully assessed; therefore, we are not inclined to make this commitment in our IRP Action Plan. However, the comment has merit and may be considered separately. We further believe this is the type of discussion that could have merit in the modeling workshop(s) contemplated in Action Plan item5..