Analytical Review of PNM's IRP

Michael Goggin, Grid Strategies LLC

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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]

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[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]

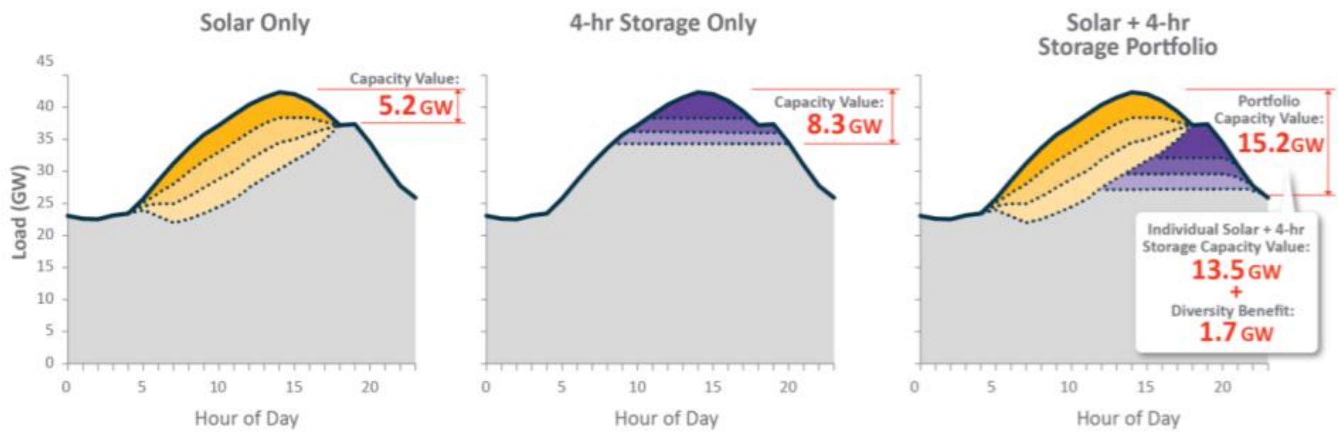


Figure 1: E3 chart showing complementary capacity value benefit between solar and storage

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)

	Hour of Day (MST)																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	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%

[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%	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 2: Historical hourly and monthly solar and wind capacity factors, from PNM's IRP

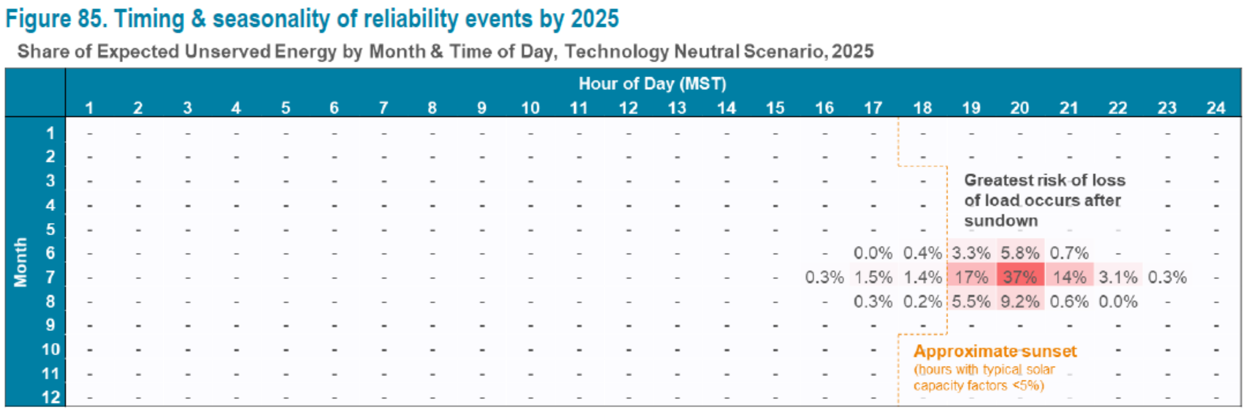
Combining the above wind and solar profiles results in a balanced portfolio that provides high levels of generation during peak load and net load hours. The following chart shows that, at a ratio of 75% wind capacity and 25% solar capacity, the wind and solar profiles complement each other to, on average, 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.



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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-	-	-
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

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[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.

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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.

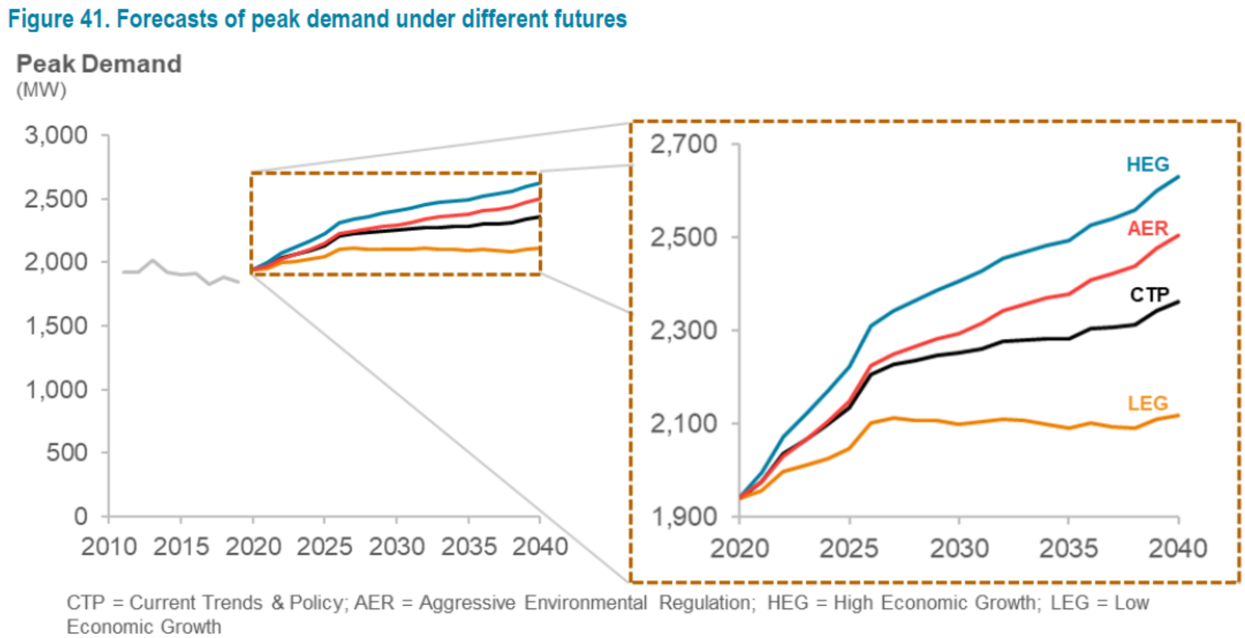

Figure 5: Historical and projected peak demand, from PNM's IRP

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]

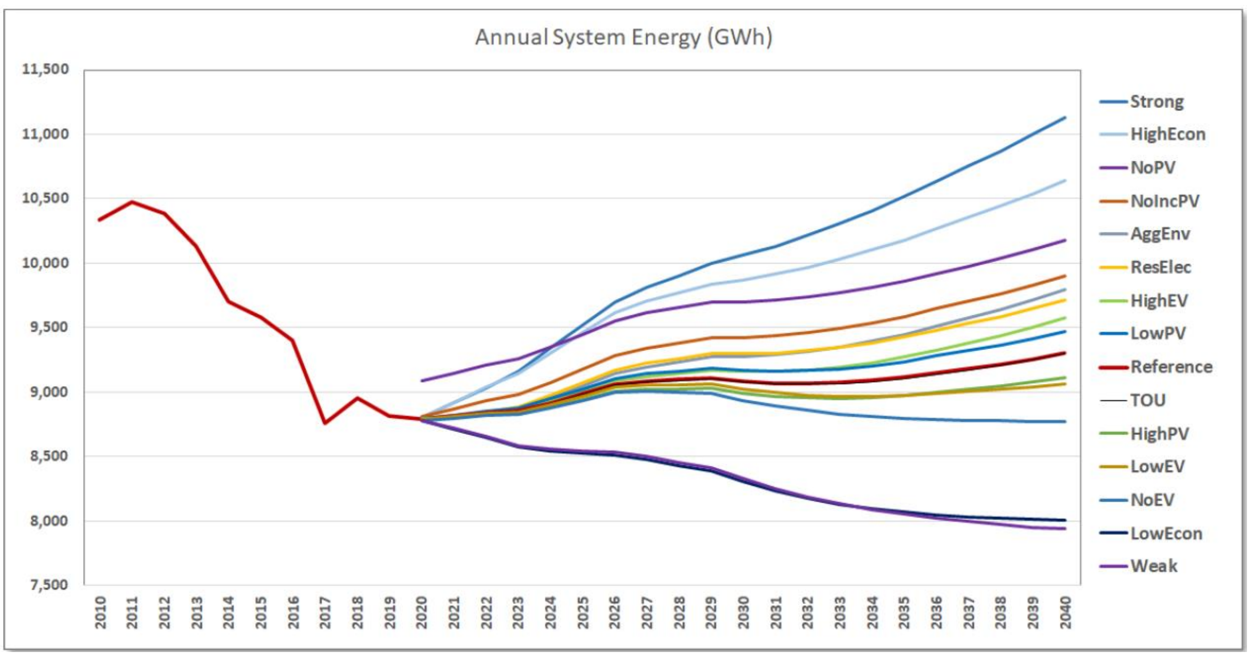

Figure 6: Historical and projected energy demand, from PNM's IRP

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.

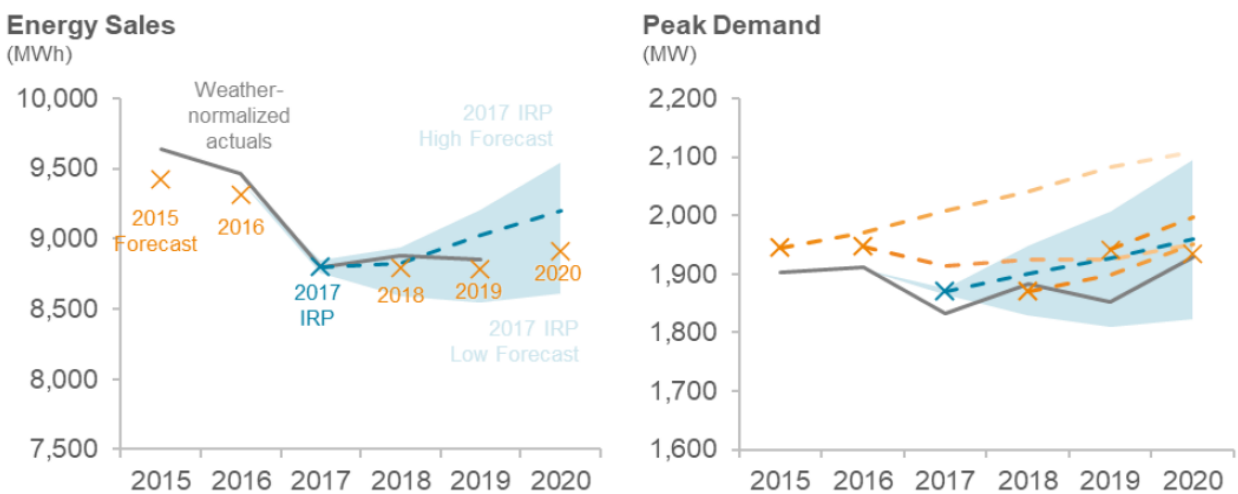

Figure 7: Historical and historically projected energy sales and peak demand, from PNM's IRP[32]

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

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[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

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[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]

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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.

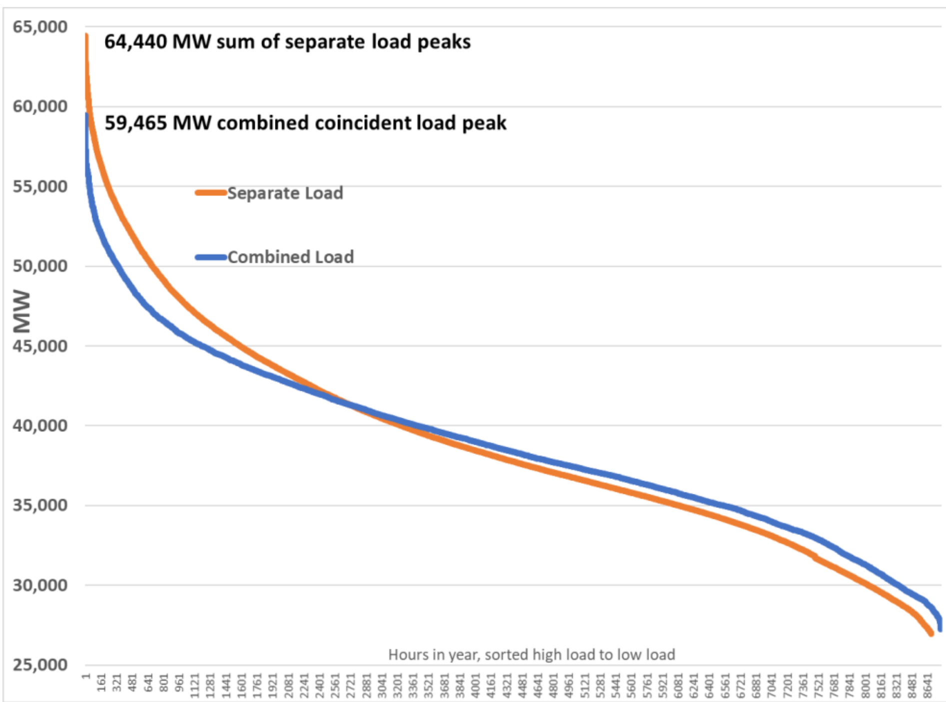

Figure 8: Peak load reduction by aggregating across US portion of NWPP

[53] https://www.eia.gov/electricity/gridmonitor/knownissues/xls/Region_NW.xlsx.

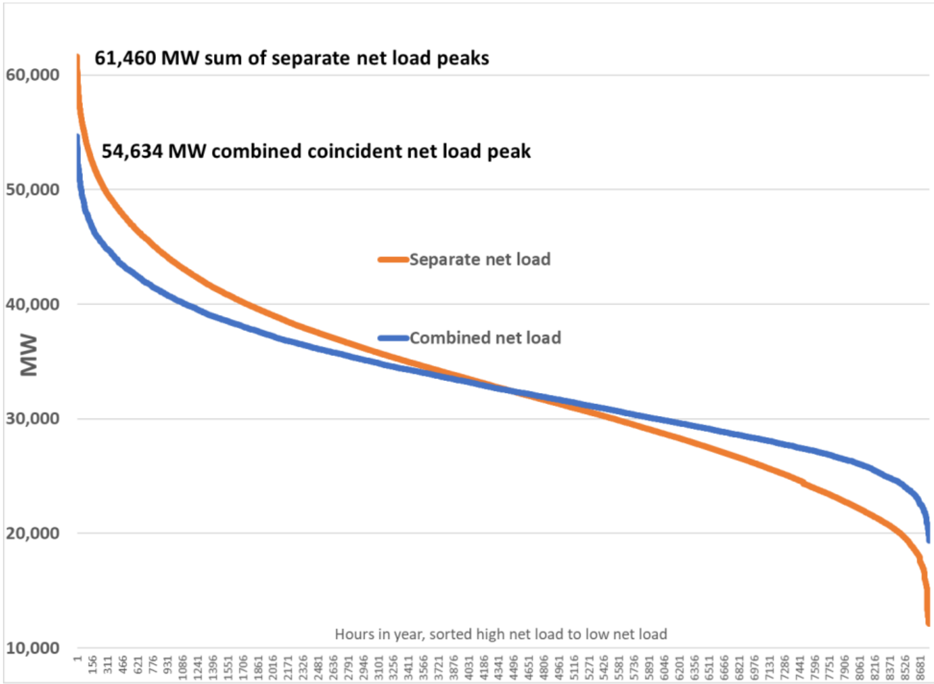

Figure 9: Peak net load reduction by aggregating across US portion of NWPP

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]

<u>Increased transmission capacity and more coordinated regional planning and operations will further help PNM meet resource adequacy needs with market purchases</u>

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.

<u>Broader regional coordination will reduce PNM's need for capacity</u>

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

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[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

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[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.

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[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.