2026 PNM Integrated Resource Plan Supporting Analysis

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Abbreviations

4HR	Four-hour duration storage
8HR	Eight-hour duration storage
AGC	Automatic Generation Control
BA	Balancing Area
CBO	Congressional Budget Office
CC	Combined cycle generating unit
CT	Combustion turbine
CTP	Current Trends and Policy
DR	Demand response
E3	Energy and Environmental Economics, Inc.
EFOR	Equivalent Forced Outage Rate
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EPE	El Paso Electric
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GWh	Gigawatt-hour
HEG	High Economic Growth
ICAP	Installed (nameplate) capacity
IRP	Integrated Resource Plan
kW	Kilowatt
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
MW	Megawatt
MWh	Megawatt-hour
NMPRC	New Mexico Public Regulation Commission
NMWEC	New Mexico Wind Energy Center
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
PNM	Public Service Company of New Mexico
PRM	Planning Reserve Margin
PSCo	Public Service Company of Colorado
PSH	Pumped storage hydro
PV	Photovoltaic
RFP	Request for Proposals
SAM	System Advisor Model (NREL solar modeling tool)
SERVM	Strategic Energy and Risk Valuation Model

Executive Summary

PowerGEM conducted a suite of resource adequacy and reliability analyses in support of the Public Service Company of New Mexico (PNM) 2026 Integrated Resource Plan (IRP), all performed using the Strategic Energy and Risk Valuation Model (SERVM). Determining the Planning Reserve Margin (PRM) and accrediting resources within a single, synchronized analysis ensures the targeted reserve margin and resource accreditation for PNM's fleet of resources are aligned in the context of resource adequacy. The analysis comprised the determination of the PRM and existing resource accreditation for the 2029 base case, which represents PNM's expected 2029 resource portfolio and load forecast as described in the **SERVM Model Inputs** section of this report, incremental Effective Load Carrying Capability (ELCC) values for new candidate resources, reliability verification of PNM's expansion portfolios, a resiliency analysis under extreme weather, and a transmission import sensitivity.

PowerGEM first analyzed the system to set a baseline of resource adequacy, given PNM's existing fleet of resources and load level. The base case of existing resources was calculated to have a Loss of Load Expectation (LOLE) below the 0.1 target, meaning the modeled portfolio carried more dependable capacity than required for the reliability standard. Economic development load was added to calibrate the system to the 0.1 LOLE target, resulting in a PRM of 14.5%. The existing fleet was accredited entirely on an ELCC basis: wind, solar, battery storage, and demand response (DR) through the Delta Method, and the conventional thermal fleet through a thermal ELCC analysis. The full accreditation by technology and calculated PRM is shown below in **Table 1**.

Table 1: Resource Accreditation and Planning Reserve Margin

Unit Category	ICAP (MW)	ELCC (%)	Accreditation (MW)
Battery	1,950	75%	1,471
Combined Cycle	425	92%	393
Combustion Turbine	786	98%	774
Demand Response	35	59%	21
Geothermal	11	76%	8
Nuclear	288	94%	271
Solar	2,412	19%	458
Steam Turbine Coal	200	72%	143
Steam Turbine Gas	145	92%	133
Wind	1,408	12%	169
Total Accredited Capacity			3,841
Peak Load at 0.1 LOLE			3,354
Planning Reserve Margin			**14.5%**

To properly capture resource accreditation as the penetration of energy-limited technologies changes over time, incremental ELCC values were developed for solar, wind, 4-hour (4HR) storage, 8-hour (8HR) storage,

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pumped storage hydro (PSH), DR, and energy efficiency and used as inputs for the expansion planning analysis.

A transmission sensitivity was performed in SERVM to evaluate the reliability benefit of increased summer import capability. The analysis showed that doubling the summer peak import capacity from 50 MW to 100 MW produced an approximate 40 MW reliability benefit, corresponding to a reduction of roughly 1.4 percentage points in the targeted PRM, from 14.5% to 13.1%.

After PNM determined its candidate expansion portfolios for the Current Trends and Policy (CTP) and High Economic Growth (HEG) futures, these portfolios were then simulated for study years 2036, 2040, and 2045 to verify their reliability against the 0.1 LOLE target. The incremental 4HR storage adjustment needed to bring each portfolio to the 0.1 LOLE target was calculated. The results are shown in **Table 2** and **Table 3**. A stakeholder-proposed portfolio was also simulated to verify its resulting LOLE and is included in the body of the report.

Table 2: CTP Portfolio Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	38	18.8%	−170
2040	0.23	221	13.6%	+285
2045	0.08	99	14.2%	−90

Table 3: HEG Portfolio Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	34	18.6%	−230
2040	0.11	80	15.2%	+20
2045	0.03	19	15.1%	−190

Finally, a resiliency analysis was performed on PNM's CTP and HEG portfolios. This analysis evaluated portfolio performance during an extreme summer weather week and an extreme winter weather week, each simulated with and without market assistance. The results are shown below in **Table 4** and **Table 5**. More discussion on these results is included in the body of the report but it is clear PNM's interconnections provide significant resiliency benefit.

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Table 4: Summer Resiliency Weekly EUE (MWh)

Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	6	3,758
CTP	2040	1	4,383
CTP	2045	4	2,509
HEG	2036	33	3,892
HEG	2040	13	3,596
HEG	2045	7	1,152

Table 5: Winter Resiliency Weekly EUE (MWh)

Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	259	9,259
CTP	2040	614	10,237
CTP	2045	76	3,823
HEG	2036	252	17,187
HEG	2040	528	6,061
HEG	2045	54	2,470

A second analysis compared how different resource types contribute to resiliency. Starting from the CTP 2036 portfolio calibrated to 0.1 LOLE, 100 MW of load was added to the portfolio. LM6000 combustion turbine, 4HR storage, DR, and combined solar and storage technologies were each added independently in the amount needed to return the system to the 0.1 LOLE target.

When each resource was sized to meet the same 0.1 LOLE target, annual expected unserved energy (EUE) was lowest for the LM6000, followed by DR, then combined solar and storage, and highest for stand-alone 4HR storage. The difference is largest under sustained winter conditions, where energy-limited resources cannot maintain output across extended extreme weather circumstances. The ordering of the technologies changes under extreme summer conditions, where shortfalls are concentrated in a few evening hours that fall within the discharge duration of storage, and because there is significant capacity added to achieve 0.1 LOLE, DR and the storage-based resources hold EUE below that of the LM6000, with DR clearing the extreme summer week entirely. Again, to achieve a 0.1 LOLE, 580 MW of DR was needed versus 105 MW of the LM6000 resource. The results are summarized below in ***Table* 6**.

Table 6: 2036 Resiliency Comparison of Different Technologies

Marginal Resource	Marginal MW	Full Study Annual EUE (MWh)	Summer Extreme Week EUE (MWh)	Winter Extreme Week EUE (MWh)
LM6000	105	67	26	145
4HR	345	107	13	603
Demand Response	580	73	0	474
Solar and Storage	580/290	100	<1	463

Study Methodology

Scope of 2026 IRP Analysis

PowerGEM performed a suite of resource adequacy and reliability analyses in support of PNM's 2026 IRP, all conducted using SERVM. The analysis comprised five workstreams:

- **Database Development:** Update the SERVM database with the best available data. The processes involved are detailed in the SERVM Model Inputs section.
- **PRM and Existing ELCCs:** Determination of the PRM and ELCC accreditation of the existing resource fleet for the 2029 base case study year.
  - **Transmission Sensitivity:** Examining the reliability benefit of increased summer import capability.
- **Incremental ELCCs:** ELCC values for incremental resource additions to support expansion planning.
- **Portfolio Reliability Checks:** Verification that PNM's candidate expansion portfolios meet the 0.1 LOLE target.
  - **Stakeholder Proposed Scenario:** Simulate the portfolio in SERVM to verify LOLE.
- **Resiliency Analysis:** Evaluation of portfolio performance under extreme summer and winter weather conditions.
  - **Resiliency Comparison of Different Technologies:** Compare the impact that different resource classes have on resiliency.

The workflow is illustrated in **Figure 1** below and the methodology for each workstream is described in detail in the sections that follow.

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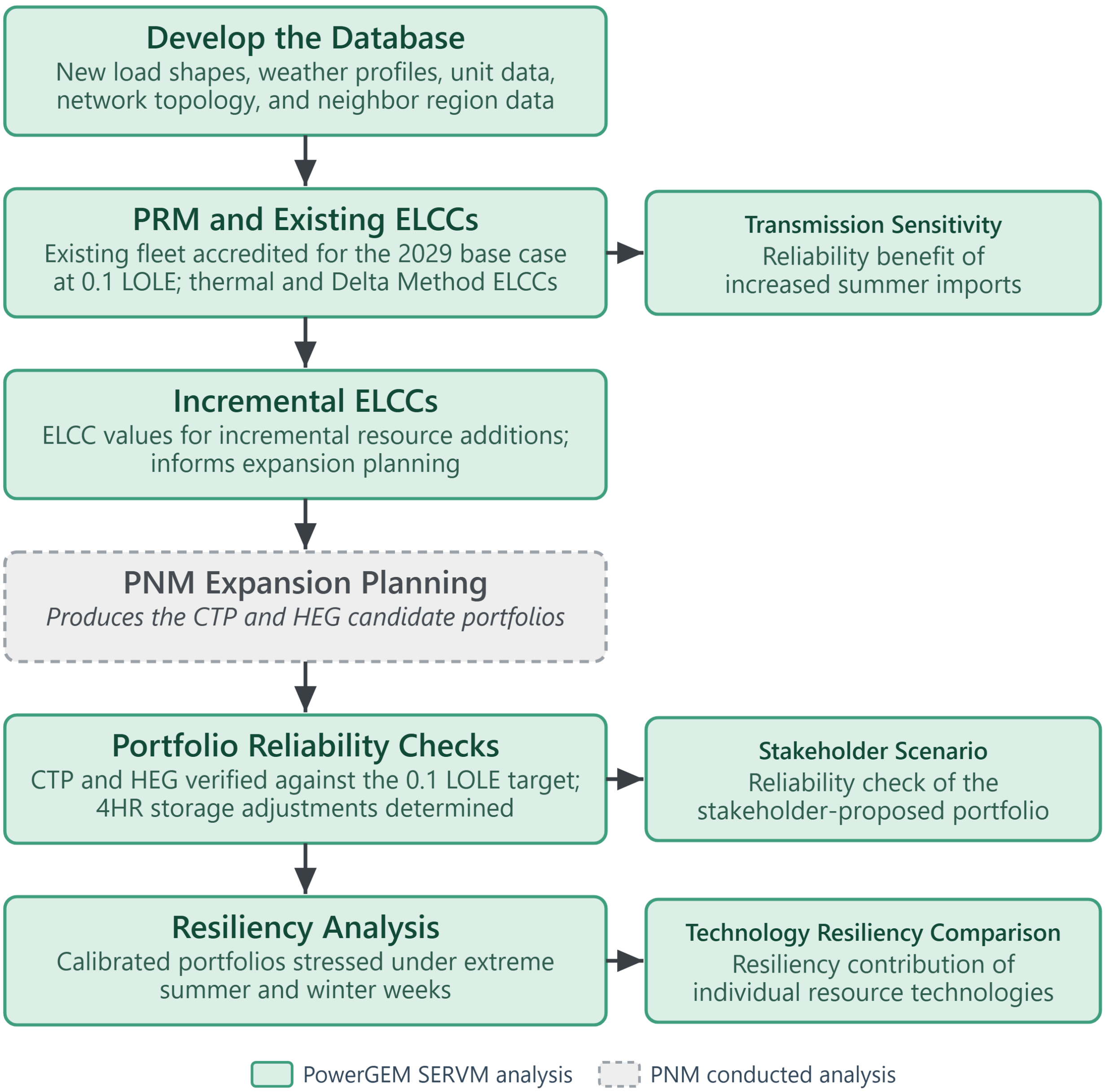
Figure 1: 2026 IRP Resource Adequacy Workflow



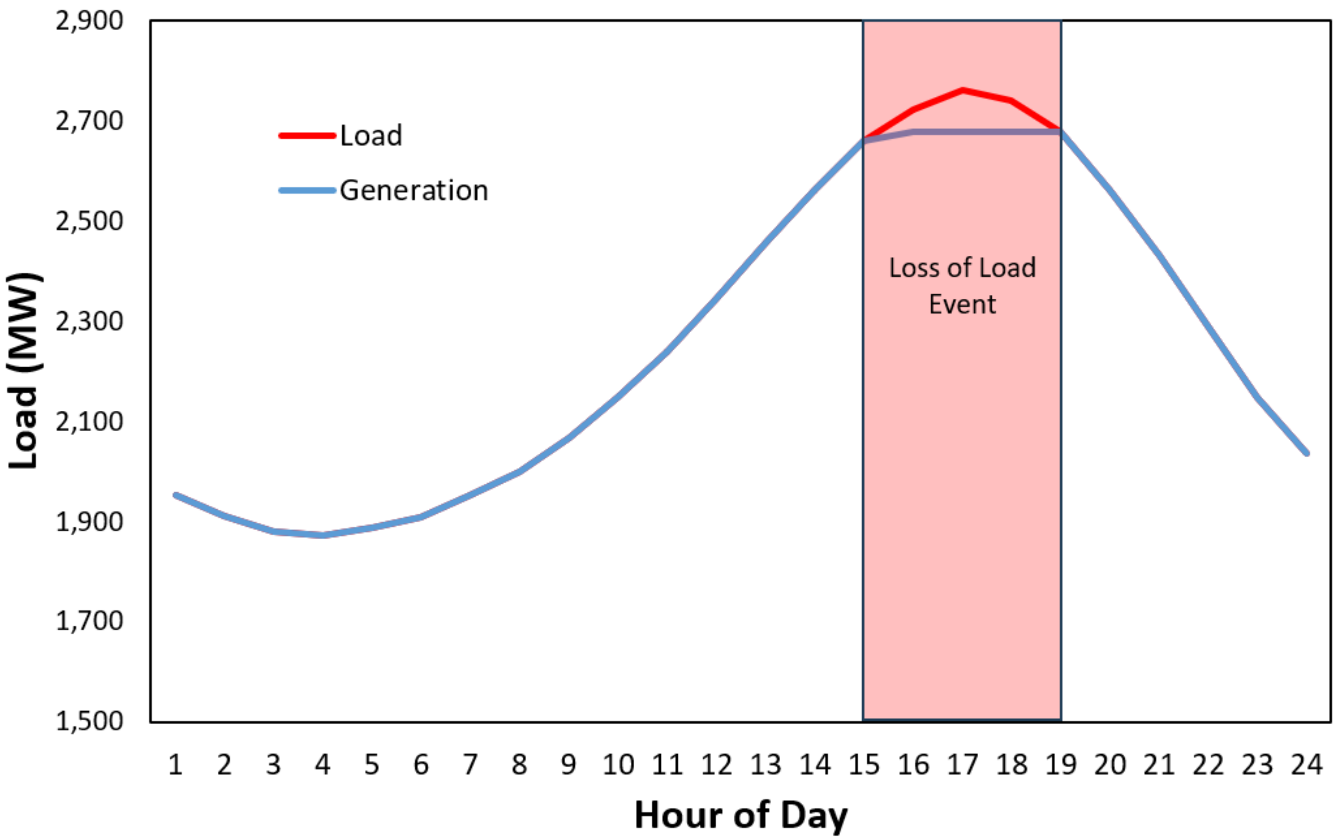
Planning Reserve Margin and Existing ELCCs

Planning Reserve Margin

The PRM is the amount of dependable resource capacity a system must carry above its expected peak demand to maintain target reliability metrics. It is expressed as the ratio of accredited capacity in excess of peak load to the peak load itself. Determining the PRM and accrediting resources within a single, synchronized analysis ensures that the capacity a resource is credited with contributing is consistent with the capacity the system relies upon to meet its reliability target.

The reliability target used to establish the PRM in this analysis is LOLE, defined as the expected number of days per year on which available capacity is insufficient to serve firm load. Such a capacity shortfall typically occurs across the peak of a day, when demand is highest relative to available supply. **Error! Reference source not found.Figure 2** illustrates an example of this type of loss of load event.

Figure 2: Loss of Load Event Illustration



PNM targets the LOLE reliability standard of 0.1 days per year. LOLE is a probabilistic measure of how often available resources are expected to fall short of load, evaluated across thousands of simulated combinations of weather, load, forced outages, and variable generation output. The one-day-in-ten-years criterion is the standard planning basis across North America[1]. RTOs such as the PJM Interconnection[2] and Midwest Independent System Operator (MISO)[3] use the one-day-in-ten-years standard. Utilities such as

[1]NERC, Long Term Reliability Assessment. Available at https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

[2] https://www.pjm.com/-/media/documents/manuals/m20a.ashx, page 8.

[3] https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf, page 2.

Duke Energy[4] and Arizona Public Service Company[5] also use the same standard to ensure resource adequacy on their respective systems.

A base case was created and used as the foundation for determining the PRM, existing ELCCs, and incremental ELCCs. The base case represents PNM's expected 2029 system: the existing and planned resource portfolio paired with the 2029 CTP load forecast, simulated under the weather, outage, and market assistance assumptions described in the **SERVM Model Inputs** section. It is the starting point against which every other case in this report is measured. This base case was modeled for the 2029 study year with the existing resources shown in **Table 15** and the load forecasts shown in the **Load Forecasts and Load Shapes** section of this report.

The PRM, illustrated in **Figure 3,** is determined as follows. The base case was simulated in SERVM at its forecasted load and was calculated to have an LOLE below the 0.1 target, meaning the modeled portfolio carried more dependable capacity than required for the reliability standard. This initial set of existing resources assumed additional gas resources PNM had identified in its 2029–2032 System Resources application filed with the New Mexico Public Regulation Commission (NMPRC) in mid-2026. PNM utilized generic gas resources to serve as placeholders until it determines actual resources that PNM intends to procure, following evaluation of Request for Proposals (RFP) bids it plans to receive in the second half of 2026. To calibrate the system to the target, economic development load was added until the system reached 0.1 LOLE. This calibrated load level represents the peak demand that the resource portfolio can serve at the reliability standard.

At the calibrated 0.1 LOLE level, each resource is credited by its ELCC rather than its installed capacity (ICAP):

- Firm and conventional thermal resources are accredited using the thermal ELCC values described below.[6]
- Wind, solar, battery storage, and DR resources are accredited using ELCC values developed through the Delta Method described below.

The PRM is then calculated as the ratio of total accredited capacity in excess of the calibrated peak demand to that peak demand. Because all resource types are accredited on an ELCC basis, the resulting PRM reflects the true reliability contribution of each technology in the context of the full portfolio. The PRM established through this process provides the accreditation basis carried forward into the expansion planning and portfolio reliability analyses. Additionally, 12x24 heat maps showing the timing and

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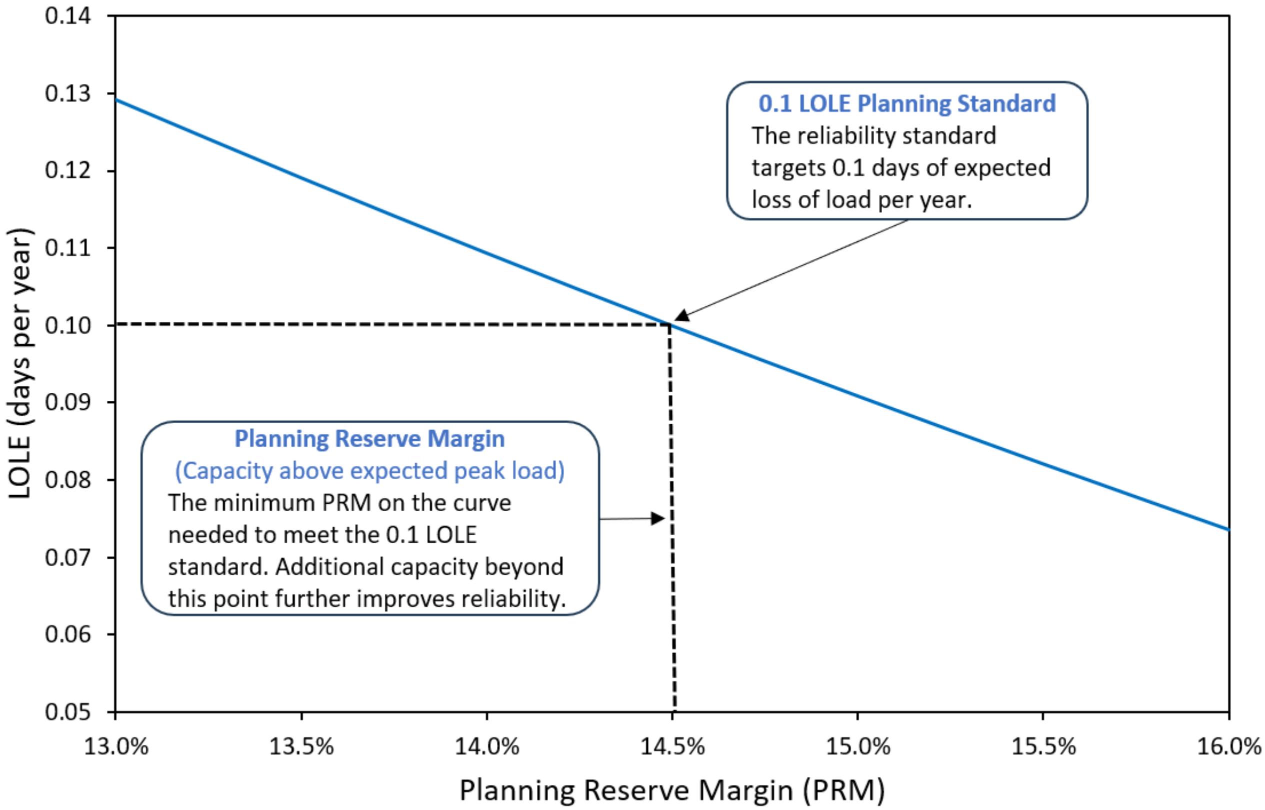
[4] https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-1-changing-energy-landscape.pdf?rev=88d3584893bc4287be612875fae8bea8, page 7.
[5] https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&sc_lang=en&hash=DF34B49033ED43FF0217FC2F93A0BBE6, page 14.
[6] Due to its small nameplate capacity PNM's single geothermal unit was accredited using the UCAP methodology from last IRP of 1-EFOR.

magnitude of loss of load events for the base case calibrated to 0.1 LOLE are provided in the body of the report.

Figure 3: Planning Reserve Margin and 0.1 LOLE Planning Standard



Thermal ELCCs

Conventional thermal resources were accredited using an ELCC methodology applied at the resource category level. The thermal fleet was grouped into five categories: combined cycle (CC), combustion turbine (CT), nuclear, steam coal, and steam gas. The 2029 base case, calibrated to the 0.1 LOLE reliability target, served as the starting point for the analysis.

For each category, the ELCC for these firm dispatchable resources was determined as follows. The entire category was removed from the system, which increased LOLE, and perfect capacity[7] was then added back at several discrete megawatt levels. The resulting LOLE was recorded at each level, and the perfect capacity required to return the system to the base case LOLE was determined by interpolating across these points. The quantity of perfect capacity represents the accredited megawatt contribution of the category, and dividing it by the category's installed capacity yields the raw ELCC value.

To capture the combined contribution of the fleet, the entire thermal portfolio was then removed at once and the same procedure was applied, yielding the total portfolio thermal ELCC. Because of the effect of

[7] Perfect capacity was modeled as a resource with no outages, planned maintenance, or ramping constraints.

planned maintenance scheduling, the sum of the independently calculated category values does not exactly equal the portfolio value determined with all thermal units removed together. To reconcile this, the individual category ELCC megawatts were prorated so that their sum equals the total portfolio ELCC. The resulting category ELCC values were then applied in the PRM calculation to convert installed thermal capacity to accredited capacity.

The Delta Method

To calculate the ELCC of PNM's existing variable energy and energy-limited resources, such as wind, solar, battery storage, and demand-side resources, the Delta Method was used. The Delta Method by Energy and Environmental Economics, Inc. (E3)[8] is a widely used methodology to allocate portfolio ELCC among resource categories. The Delta Method relies on three measured ELCC values:

- **Portfolio ELCC:** total ELCC for a combination of variable energy and energy-limited resources.
- **First-In ELCC:** the marginal ELCC of each individual resource in a portfolio with no other variable energy or energy-limited resources.
- **Last-In ELCC:** the marginal ELCC value of each individual resource when taken in the context of the full portfolio.

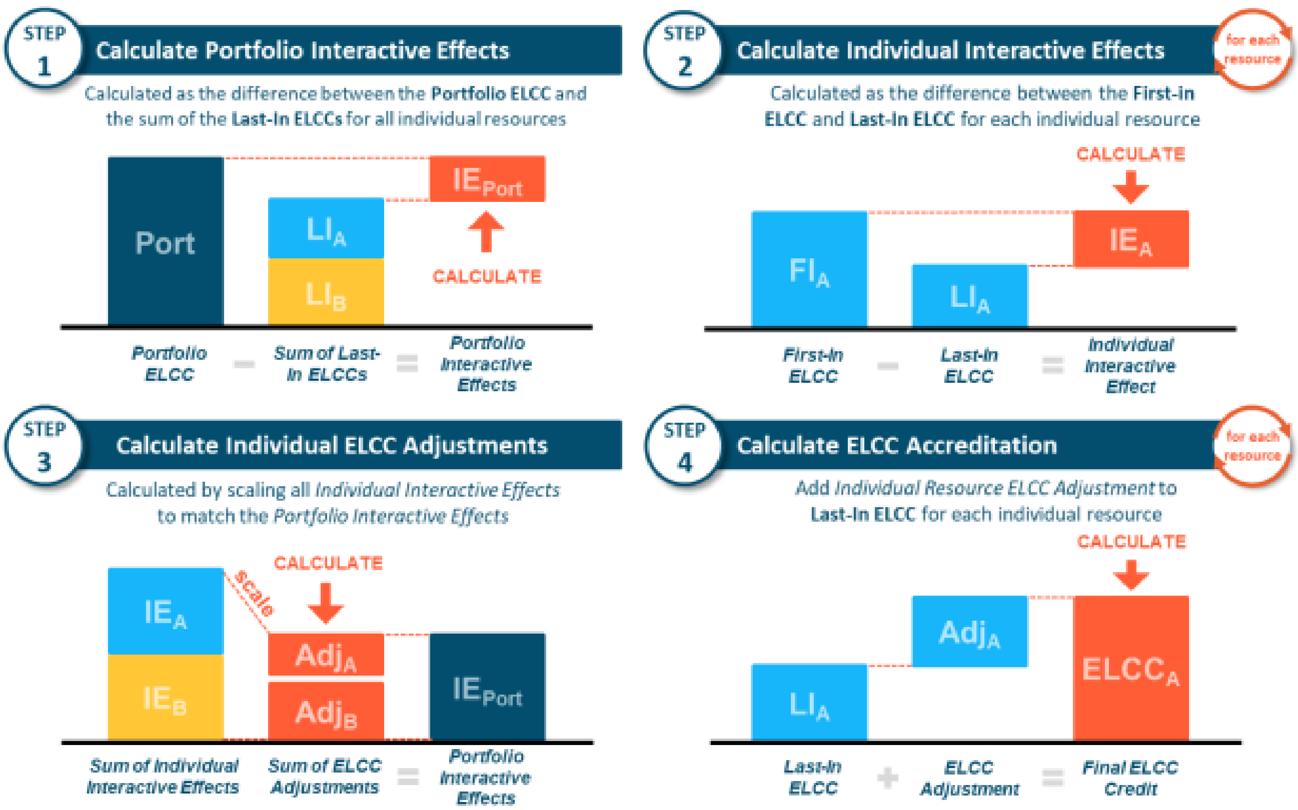
The steps of the Delta Method are as follows:

- **Calculate Portfolio Interactive Effects:** the difference between the portfolio ELCC and the sum of the Last-In ELCCs for all individual resources.
- **Calculate Individual Interactive Effects:** the difference between the First-In ELCC and the Last-In ELCC for each individual resource.
- **Calculate Individual ELCC Adjustments:** calculated by scaling all individual interactive effects to match the portfolio interactive effects.
- **Calculate ELCC Accreditation:** add individual resource ELCC adjustments to the Last-In ELCC for each individual resource to get the final ELCC credit.

Figure 4, sourced from E3's whitepaper, illustrates the four steps of the Delta Method described above, showing how the Portfolio, First-In, and Last-In ELCC values are combined to produce a final ELCC credit for each resource.

[8] E3, Practical Application of ELCC. Available at https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Figure 4: Delta Method Illustration



Incremental ELCC Methodology

In addition to accrediting the existing fleet, ELCC values were developed for incremental additions of resources to inform the expansion planning process. Incremental ELCCs were calculated for wind, solar, 4HR storage, 8HR storage, pumped storage hydro, DR, and energy efficiency resources.

The incremental ELCC of each resource type was determined using a load addition approach, beginning from the 2029 base case near the 0.1 LOLE reliability target. For each resource type, incremental resource capacity was added to the system, which reduced LOLE below the base case level. Load was then added at several levels, and the resulting LOLE was recorded at each. The amount of load required to return the system to the base case LOLE was determined by interpolating LOLE across the load levels. That quantity of load is the accredited ELCC at that installed capacity level and dividing it by the block's nameplate capacity yields the ELCC percentage.

For solar and the three storage types, this process was repeated at increasing penetration levels, producing results at successive tranches. Solar was evaluated on its own, while each storage type was evaluated with solar co-added at a 2:1 solar-to-storage ratio. At each penetration, two ELCC measures were derived: an average ELCC, representing the cumulative contribution of the entire block up to that penetration, and a tranche ELCC, representing the marginal contribution of each successive increment. A curve was then fit to the tranche ELCC values as a function of incremental capacity for each of these resource types, providing a continuous incremental ELCC curve across the studied penetration range. Wind was evaluated at discrete penetration levels without fitting a continuous curve, and DR and energy efficiency were each evaluated at a single incremental level.

Portfolio Reliability Verification Methodology

As part of the expansion plan modeling process, PNM developed candidate resource portfolios representing its CTP and HEG futures. Each portfolio was simulated in SERVM and results were compared to the 0.1 LOLE reliability target. The CTP and HEG portfolios were each simulated across the 2036, 2040, and 2045 study years.

For each portfolio and study year, the entire fleet of resources was modeled at the corresponding demand and energy requirements and the resulting system LOLE was calculated. Where a portfolio's LOLE deviated from the target of 0.1 LOLE, the amount of 4HR storage required to return the system to 0.1 LOLE was determined. This was done by simulating the portfolio across several 4HR storage adjustment levels, recording the resulting LOLE at each, and interpolating the storage quantity that yields 0.1 LOLE. Storage was added where the portfolio was unreliable, with an LOLE above 0.1, and removed where it was over-reliable, with an LOLE below 0.1. For portfolios and years where 4HR adjustments were identified, such amounts were tabulated; however, the expansion plan portfolios were not adjusted by those amounts of 4HR storage. In addition to the CTP and HEG portfolios, a stakeholder-proposed scenario portfolio was simulated across the same study years to verify its resulting LOLE.

12x24 heat maps showing the timing and magnitude of loss of load events for the CTP and HEG portfolios for all study years calibrated to 0.1 LOLE are provided in this report.

Resiliency Methodology

The resiliency analysis consisted of two parts. The first evaluates how the CTP and HEG expansion portfolios perform under extreme summer and winter weather. The second compares, for the CTP portfolio in 2036, how much resiliency benefit different technologies provide.

Portfolio Resiliency

To evaluate how the expansion portfolios perform under extreme weather conditions, a resiliency analysis was conducted for the CTP and HEG portfolios across 2036, 2040, and 2045 study years. The portfolios analyzed were those calibrated to 0.1 LOLE in the portfolio reliability analysis, including their 4HR storage adjustments.

Rather than simulating the full set of 45 weather years, this analysis isolates the impact of severe weather by simulating a single extreme week for each season. To identify these extreme timeframes, each week across the 45 weather years was characterized by two net load measures, where net load is system load net of wind and solar generation: (1) the maximum net load reached during the week and (2) the average of the daily peak net loads across the week. Weeks were ranked on each measure within their season, and the two rankings were combined into an average rank to identify the most severe net load weeks. On this basis, the summer week selected was week 26 of 1994 and the winter week was week 5 of 2011.

Each portfolio, season, and study year combination was simulated under two market conditions: interconnected, in which the PNM system has access to market assistance from neighboring regions, and islanded, in which no market assistance is available. In the islanded cases, Tri-State regions remain included as they are modeled within the PNM Balancing Area (BA) as described in the **Study Topology and Regional Connectivity** section. Comparing the two isolates the reliability contribution of external support during stressed periods. Additionally, the islanded framework allows insight into how the system operates during extreme unserved energy events. One-hundred unit outage iterations were simulated for each case. EUE was the primary metric recorded, reported both weekly over the selected extreme week and on an annual basis, for the interconnected and islanded cases.9

Resiliency Comparison of Different Technologies

The second part of the resiliency analysis compares how different resource technologies perform under extreme conditions when each is sized to provide the same reliability, using the CTP portfolio in the 2036 study year.

Starting from the CTP 2036 portfolio at 0.1 LOLE, 100 MW of load was added, raising LOLE above 0.1 days/year. Each of four technologies was then added to the system independently, in the amount required to return the system to 0.1 LOLE:

- LM6000 combustion turbine
- 4-hour storage
- Demand Response
- Solar and storage at a 2:1 solar-to-storage capacity ratio

For each technology, the capacity needed to restore 0.1 LOLE was determined by simulating the portfolio across several capacity levels and interpolating to the amount that returns the system to the target. Because every technology is sized to the same annual reliability, the scenarios differ only in the resource providing it, which isolates how each technology performs under stress.

Each scenario was then evaluated two ways. First, EUE was compared across a full simulation of all weather years. Second, EUE and system dispatch were compared during the extreme summer and winter weeks used in the portfolio resiliency analysis.

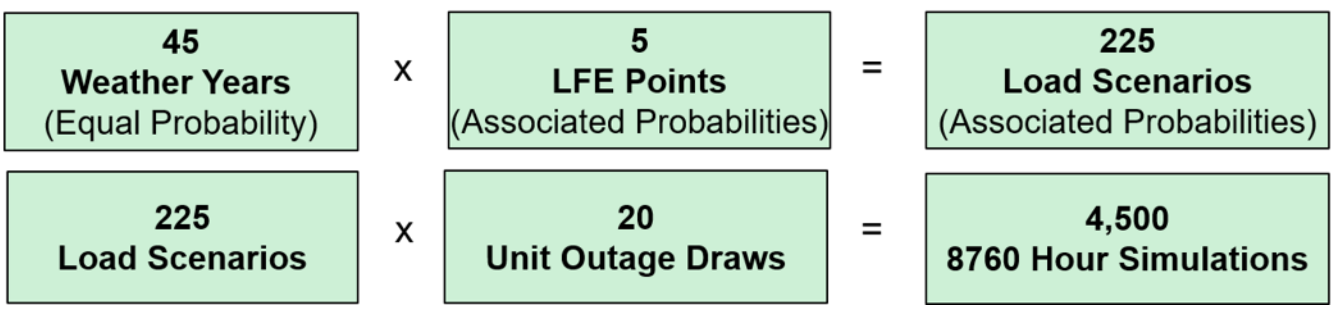
[10] 50MW Casa Mesa wind is modeled within the NWWEC wind unit in SERVM due to real world transmission constraints, so the actual capacity of the system is 1,458MW, but it is modeled at 1,408MW.

SERVM Model Inputs

SERVM Framework

Since reliability events are high impact and low probability, many scenarios must be considered to accurately assess the reliability of the PNM system. For this study, SERVM utilized 45 years of historical weather and load shapes spanning 1980 through 2024, 5 points of economic load growth forecast error, and a minimum of 20 Monte Carlo unit outage draw iterations for each scenario to represent a full distribution of realistic scenarios. The number of yearly simulation cases for each scenario is 45 weather years × 5 load forecast errors × 20 unit outage iterations = 4,500 total simulation cases for each scenario studied. Weather years and solar profiles were each given equal probability, while the load forecast error multipliers were given their associated probabilities as reported in the **Load Forecasts and Load Shapes** section.

Figure 5: SERVM Uncertainty Framework



Study Topology and Regional Connectivity

The PNM BA and its tier-one neighbors were modeled as separate regions connected by transfer limits, as shown in **Figure 6**. The PNM BA comprises three internal zones — PNM North, PNM South, and PNM San Juan and Four Corners — and was committed and dispatched as a single region along with Tri-State North and Tri-State South. The Data Center and Economic Development loads were modeled in their own independent regions, but with effectively unlimited transmission to the PNM North region. Each tie between regions was modeled with a directional transfer limit in each direction.

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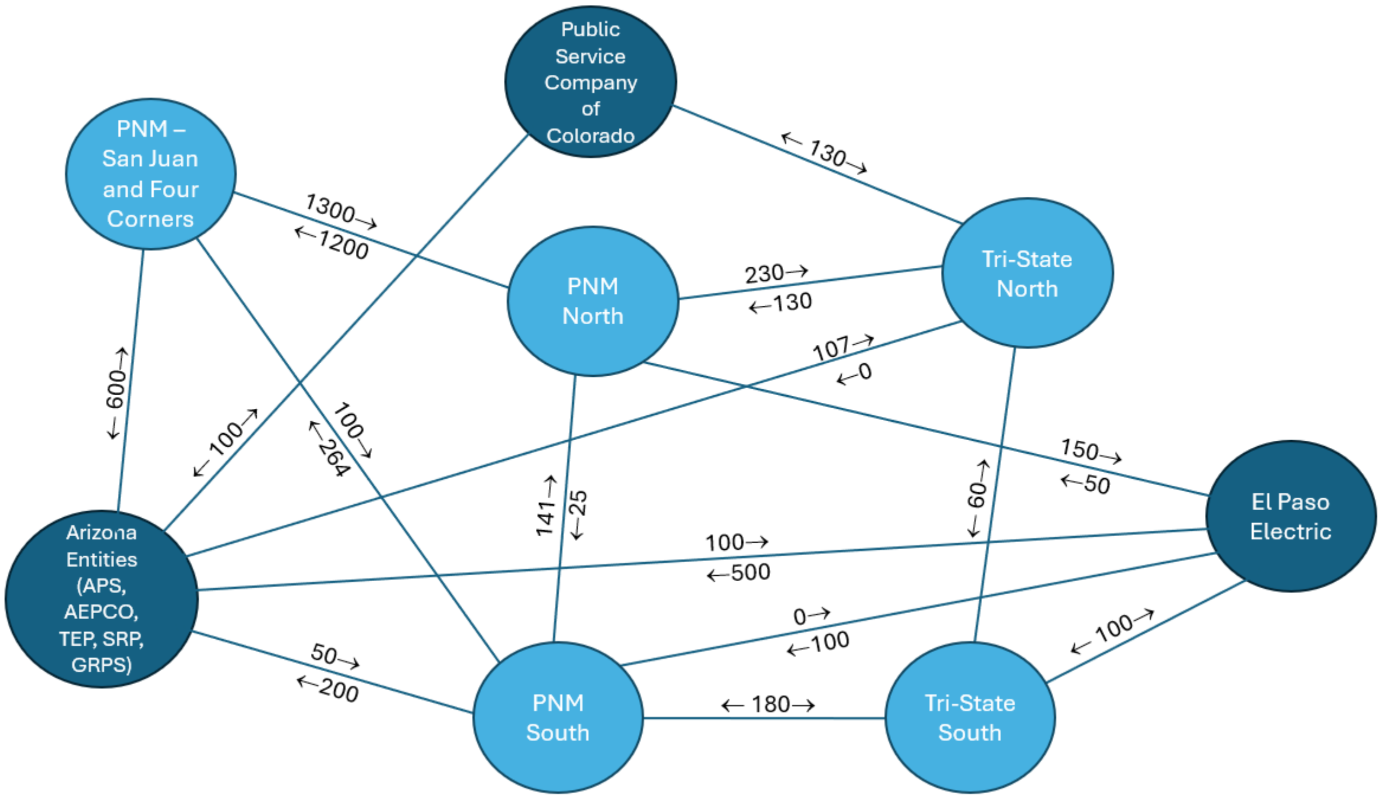
Figure 6: Study Topology and Regional Connectivity



*All values in the figure are in MW.

The tier-one neighbors modeled were El Paso Electric (EPE), an aggregate Arizona region, Public Service Company of Colorado (PSCo), and Tri-State North and South. The neighboring regions were modeled in similar fashion to PNM and the loads and resources were all developed based on publicly available data from U.S. Energy Information Administration (EIA) Form 860, Federal Energy Regulatory Commission (FERC) Form 714, and publicly available IRPs. For Tri-State, the load forecast and resource assumptions were provided directly by PNM.

Aggregated Constraints

Aggregated constraints limit the total simultaneous import capability into the PNM BA from all neighbors. This modeling parameter reflects the assumption that PNM has historically experienced lower market assistance during periods when the surrounding region is also stressed. The non-winter aggregated constraints are unchanged from the prior PNM IRP. Winter aggregated constraints were added in this IRP cycle.

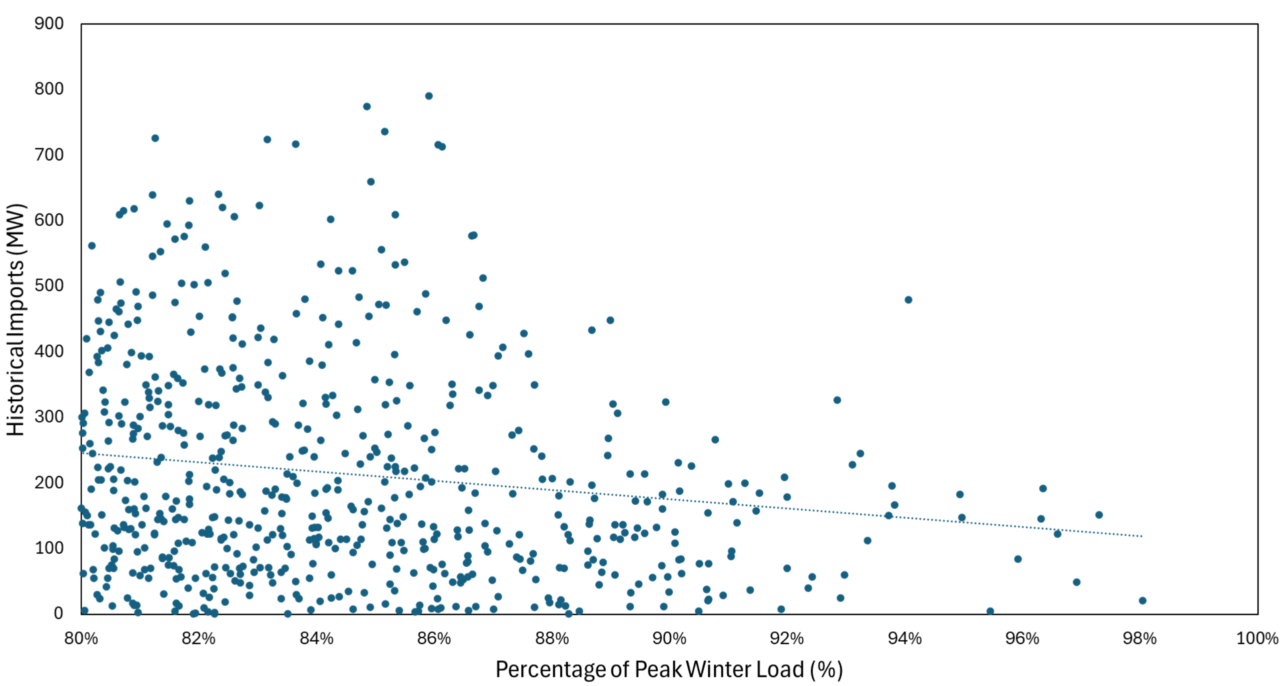
The non-winter aggregated constraints, carried forward from the prior IRP, are summarized in **Table 7**. The base constraint limits aggregate imports from all neighbors during high-load hours, and two additional constraints further restrict imports during the summer super-peak hours. The lower 80% threshold on hours 19 to 22 was applied because those hours have a gross load much less than peak daily load, ensuring the constraint still binds on peak load days.

Table 7: Non-Winter Aggregated Constraints

Constraint	Months	Hours	Gross Load Threshold	Import Limit (MW)
Base	All	All hours	≥ 85% of annual peak	200–300
Summer super-peak	June–August	16–18	≥ 85% of annual peak	100–150
Summer super-peak	June–August	19–22	≥ 80% of annual peak	50

New for the 2026 IRP, a winter aggregated constraint was added to better align modeled winter imports with historical winter import levels. The constraint was developed from historical hourly import data for the 2022 through 2025 winter seasons. **Figure 7** shows the imports observed during winter hours in which PNM was a net purchaser, plotted against the percentage of peak winter load. The observed imports rarely exceeded 800 MW and generally declined as load approached the winter peak. The winter constraint limits were selected to keep modeled winter imports consistent with these historically observed levels.

Figure 7: Historical Winter Imports



The winter constraint applies during December, January, and February, and unlike the summer constraints, which are triggered at high load levels, it varies by time of day rather than by load level, as shown in **Table 8**. Import capability is most restricted during the evening and overnight hours (hours 18 through 7), when the surrounding region is also under winter stress, and least restricted during the midday hours (hours 10 through 15).

Table 8: Winter Aggregated Constraint

Hour of Day	Import Limit (MW)
18–7	250
8	400
9	600
10–15	800
16	600
17	400

Load Forecasts and Load Shapes

There are several loads served by the PNM BA in SERVM: PNM North, PNM South, the Economic Development load, and the Data Center load. The load forecast is presented here on a combined PNM basis, shown as the seasonal peak coincident load and total energy, with the Economic Development and Data Center portions shown separately. The forecasts are shown for the 2029, 2036, 2040, and 2045 study years and are inclusive of the Economic Development and Data Center loads. The 2029 CTP forecast serves as the base case, defined in the **Planning Reserve Margin** section, which is the foundation for the PRM and ELCC analyses.

Table 9: Seasonal Peak Load Forecast (MW)

Scenario	Year	Winter	Spring	Summer	Fall
CTP	2029	2,394	2,361	3,078	2,685
CTP	2036	2,573	2,519	3,254	2,821
CTP	2040	2,732	2,656	3,387	2,963
CTP	2045	2,930	2,843	3,600	3,161
HEG	2029	2,658	2,522	3,327	2,877
HEG	2036	2,997	2,815	3,691	3,165
HEG	2040	3,276	3,064	3,952	3,419
HEG	2045	3,614	3,368	4,338	3,756
Stakeholder	2029	2,393	2,343	3,047	2,661
Stakeholder	2036	2,605	2,445	3,148	2,738
Stakeholder	2040	2,787	2,587	3,257	2,801
Stakeholder	2045	3,007	2,796	3,504	2,992

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Table 10: Seasonal Energy Forecast (GWh)

Scenario	Year	Winter	Spring	Summer	Fall
CTP	2029	4,345	4,099	4,918	4,342
CTP	2036	4,616	4,318	5,172	4,490
CTP	2040	4,726	4,406	5,302	4,604
CTP	2045	4,930	4,571	5,500	4,778
HEG	2029	4,600	4,332	5,236	4,605
HEG	2036	5,083	4,753	5,729	4,945
HEG	2040	5,335	4,979	6,024	5,197
HEG	2045	5,731	5,338	6,449	5,556
Stakeholder	2029	4,329	4,071	4,887	4,318
Stakeholder	2036	4,569	4,237	5,085	4,426
Stakeholder	2040	4,667	4,299	5,190	4,521
Stakeholder	2045	4,856	4,436	5,360	4,675

The Economic Development and Data Center load forecasts are modeled on a monthly basis and are identical across the CTP, HEG, and Stakeholder scenarios. The Economic Development load ramps up through 2036 and is then held approximately constant, while the Data Center load is held approximately constant across all study years.

Table 11: Monthly Economic Development Peak Load Forecasts (MW)

Month	2029	2036	2040	2045
1	481	590	590	590
2	496	594	594	594
3	511	600	600	600
4	510	583	585	584
5	520	583	583	584
6	512	562	562	562
7	523	561	562	563
8	553	584	584	585
9	564	585	584	584
10	587	597	597	597
11	585	595	595	595
12	580	589	590	590

Table 12: Monthly Economic Development Energy Forecasts (GWh)

Month	2029	2036	2040	2045
1	300	374	374	374
2	278	338	338	338
3	315	374	374	374
4	312	362	362	362
5	330	374	374	374
6	327	362	362	362
7	345	374	374	374
8	353	374	374	374
9	349	362	362	362
10	368	374	374	374
11	356	362	362	362
12	368	374	374	374

Table 13: Monthly Data Center Forecast

Month	Peak (MW)	Energy (GWh)
1	493	359
2	493	325
3	493	360
4	494	348
5	494	360
6	495	349
7	495	360
8	494	360
9	494	348
10	493	360
11	493	348
12	493	359

The load forecasts presented in this section reflect the expected load for each scenario and study year. As described in the Planning Reserve Margin and Existing ELCCs section, additional economic development load was added to calibrate the 2029 system to the 0.1 LOLE reliability target. The economic development load in the 0.1 LOLE calibrated run is therefore higher than the forecast values shown here.

The Data Center and Economic Development loads are each modeled with their own distinct daily load shape. The following figures show the daily shape of the Economic Development load and the Data Center load.

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Figure 8: Average July Data Center Demand

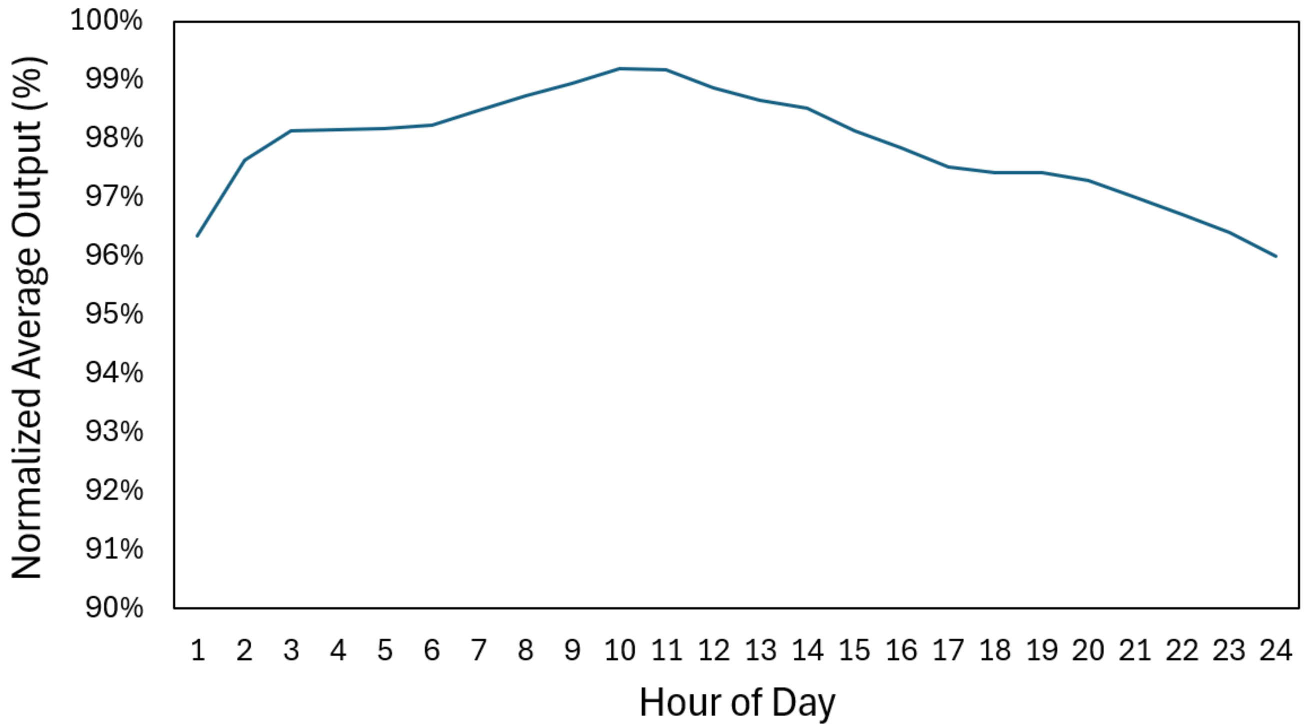
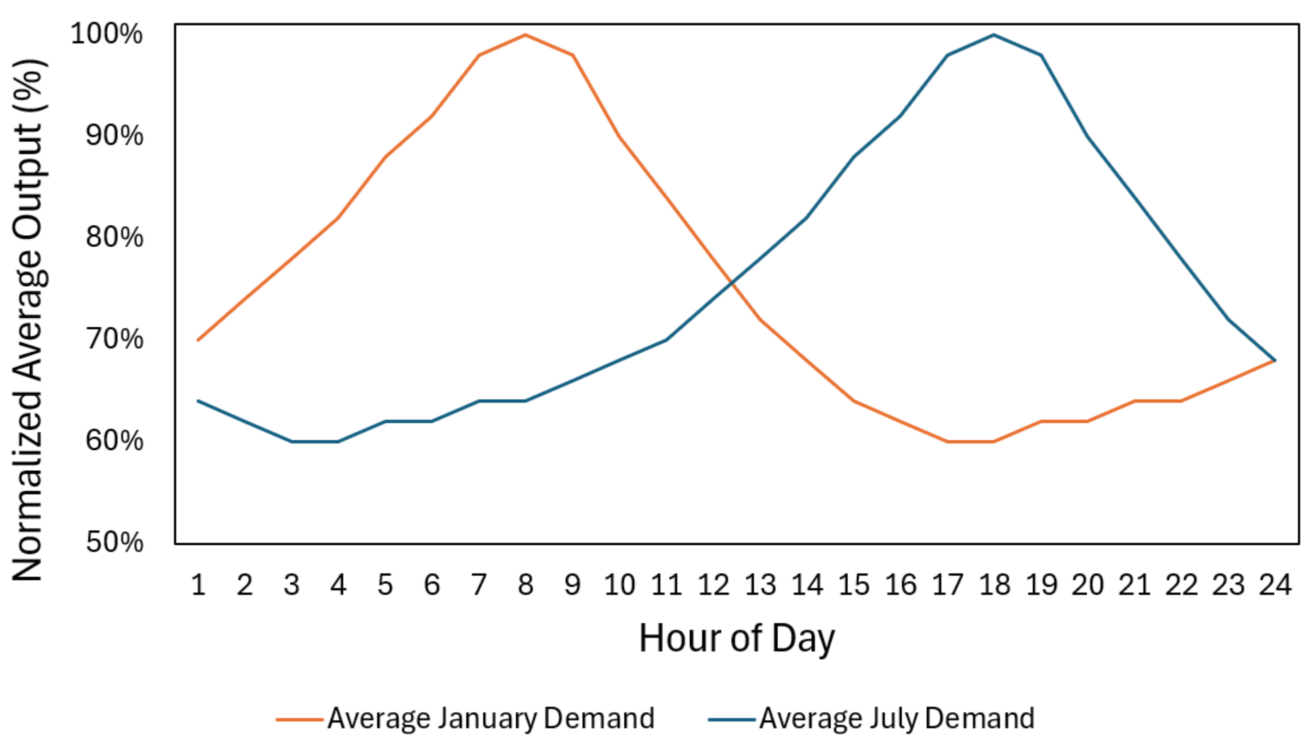


Figure 9: Average Economic Development Demand



To determine the effects of weather uncertainty on PNM's load, 45 historical years of weather and load, spanning 1980 through 2024, were compiled. Based on this history, a neural network program was used to develop relationships between weather observations and load. For the 2026 IRP, neighboring electric utility historical load data was updated so that the regional data also aligns with PNM's history. Using the resulting relationships from historical data, synthetic load shapes were created to mimic those relationships when applied to PNM's load forecasts in its 2026 IRP. By using equal probabilities given to each weather year, and scaling of load shapes such that seasonal peaks align with load forecast projections, these 45 synthetic load shapes were tested and refined to validate that the historical data continues to show a consistent relationship between weather and expected loads.

Figure 10 and **Figure 11** show the results of the synthetic load modeling by displaying the peak load variance for the total PNM load in the winter and summer seasons. The y-axis represents the percentage deviation from the 50/50 load forecast, where zero corresponds to normal weather. The bars represent the variance in projected peak loads based on weather experienced during the historical weather years. The bars are arranged from the largest negative deviation to the largest positive deviation rather than in chronological order, so the figures should be read as the distribution of weather-driven outcomes around the forecast rather than as a trend over time. The tails indicate the most extreme conditions the historical record supports.

Higher variance of the load shapes directly corresponds to higher reserves needed to maintain reliability standards. Planning reserve margin is calculated using the 50/50 load forecast, so weather years that have higher variance over the median cause the system to need more reserves to meet the increased peak load risk in those weather years. These figures offer insight into the magnitude of the effect that weather uncertainty has on the peak load of the PNM system. The 2011 weather year is a significant driver in causing winter LOLE due to an extreme cold weather event occurring in New Mexico.

Figure 10: Summer PNM Load Variance

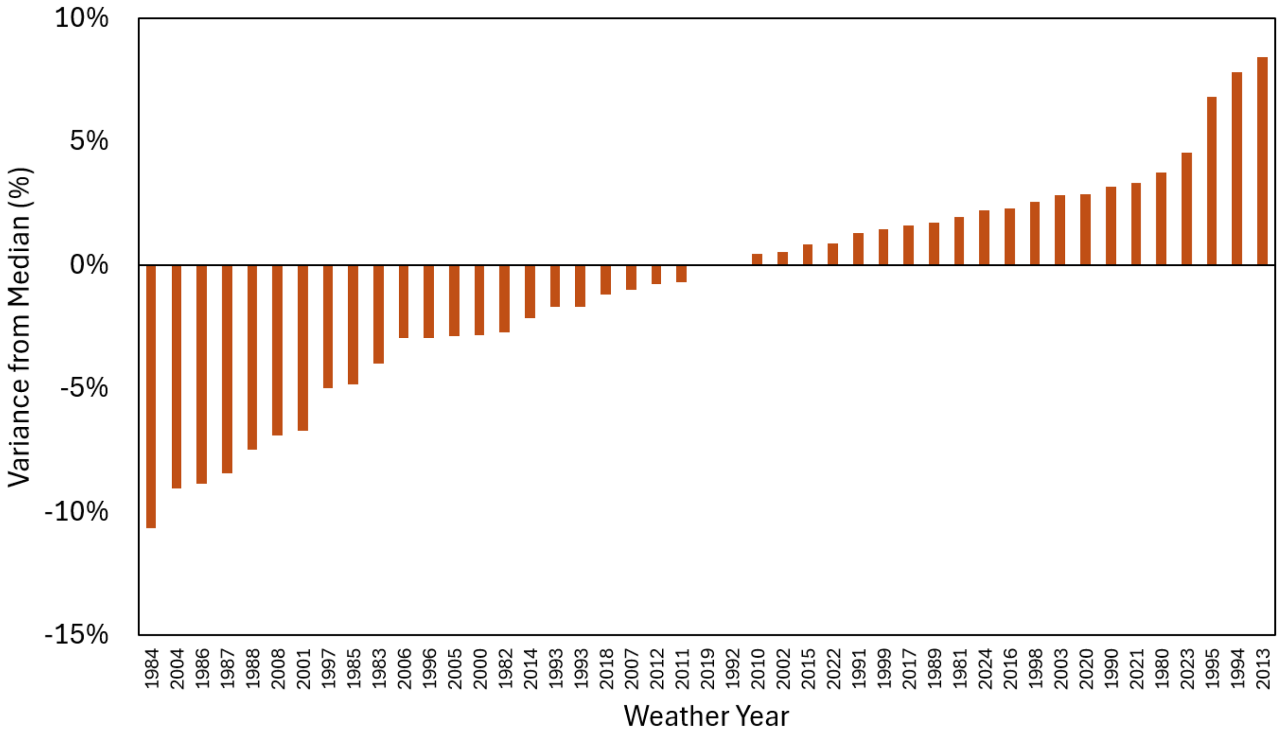
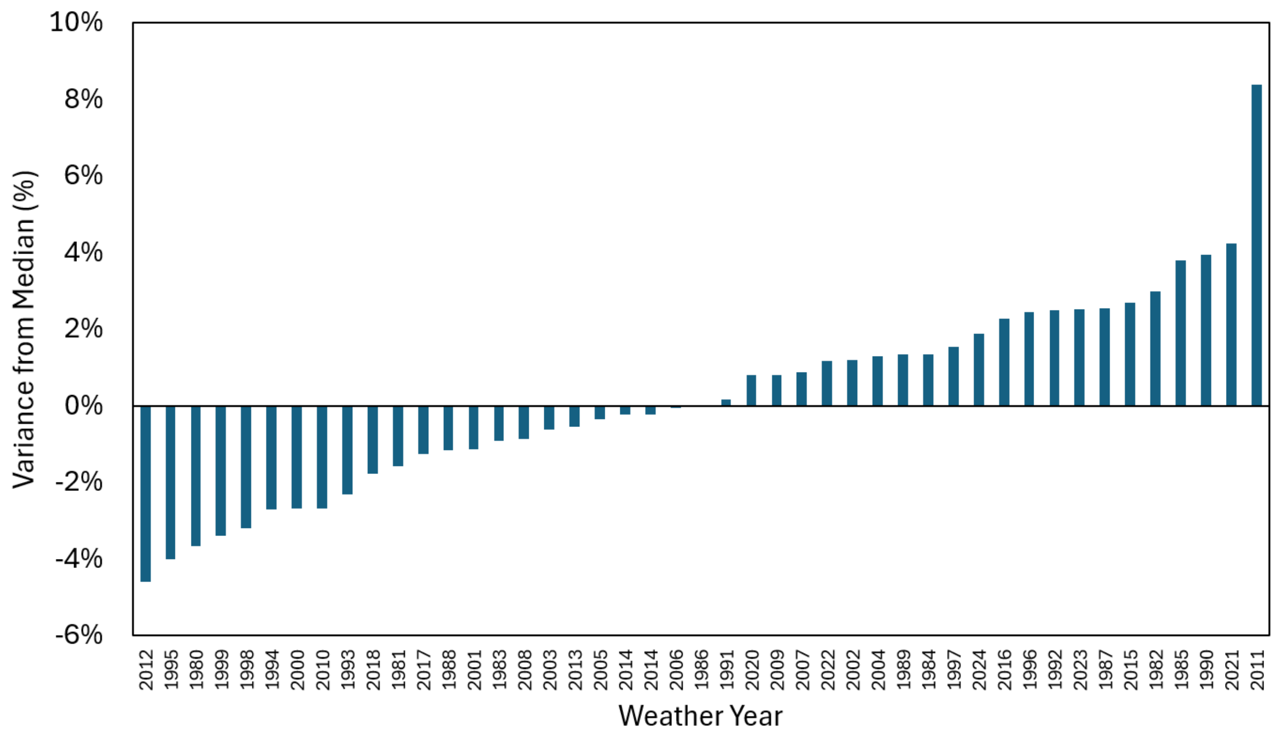


Figure 11: Winter PNM Load Variance



Economic load forecast error multipliers were included to isolate the economic uncertainty that PNM may have in its long-term load forecasts. To estimate economic load forecast error, the difference between Congressional Budget Office (CBO) gross domestic product (GDP) forecasts and actual data was fit to a normal distribution. Using a normal distribution and assuming electric load grows at a slower rate than GDP, a multiplier was applied to the raw CBO forecast error distribution. The resulting multipliers and probabilities are shown in **Table 14**. As an illustration, 11% of the time load is expected to be under-forecasted by 4%. Lastly, each of these five load forecast error points was applied to each of the 45 weather years to create 225 synthetic load shapes.

Table 14: Economic Load Forecast Error

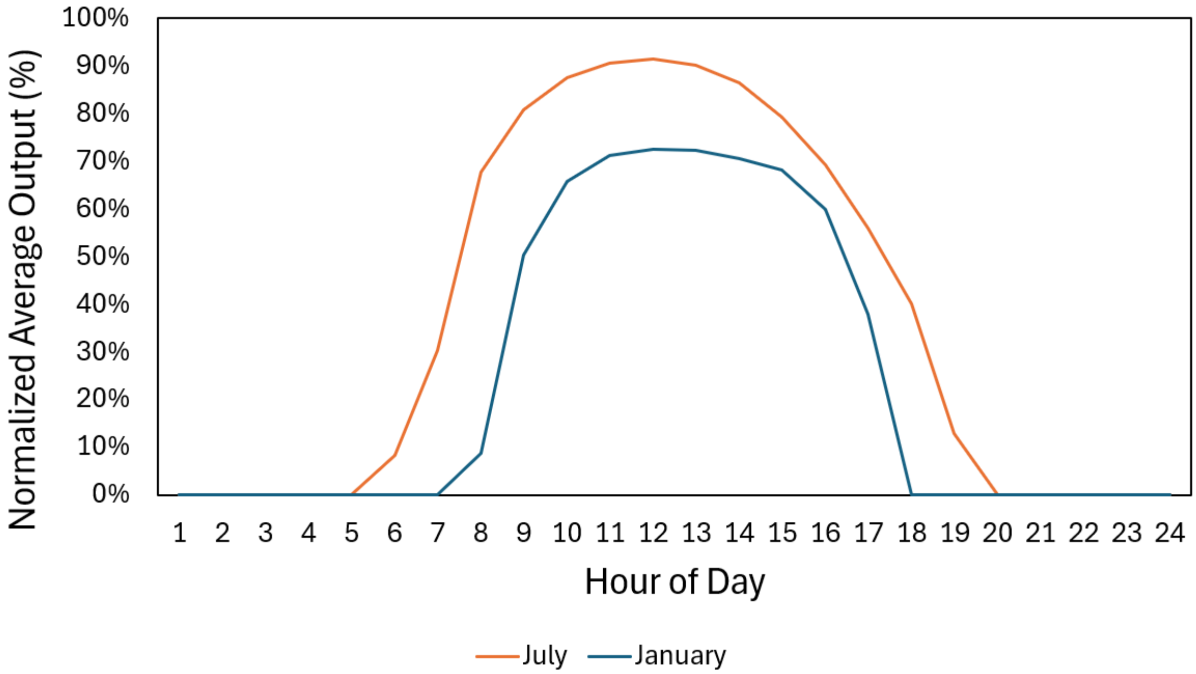
Load Forecast Error Multiplier	Probability (%)
0.96	11%
0.98	23%
1.00	32%
1.02	23%
1.04	11%

Solar Shapes

Solar data was downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) for the latitude and longitude of each of PNM's existing resource locations, for the years 1998 through 2022. Using multiple locations incorporates geographic diversity among the solar projects. The NSRDB data, which includes variables such as air temperature, dew point, global, direct, and diffuse irradiance, wind speed, surface pressure, and surface albedo, was input into NREL's System Advisor Model (SAM) for each year and location to generate hourly solar profiles for both fixed and single-axis tracking photovoltaic (PV) plants. Each solar array was modeled at a 10-degree tilt and a 180-degree (due south) azimuth. The resulting SAM output was normalized to a per-unit profile, which served as the basis for the 1998 through 2022 solar profiles. Solar profiles for the weather years outside this range, 1980 through 1997 and 2023 through 2024, were constructed from the 1998 through 2022 data using load day matching, in which daily load shapes in the years without data were compared to daily load shapes in the years with data and the solar profiles from the closest-matching days were used.

Figure 12 shows the resulting normalized aggregate solar profiles from the 2029 base case, plotted as the average daily output for January and July.

Figure 12: Average PNM Base Case Solar Output



The latitude and longitude of the PNM solar profile locations are listed in **Table 49** in the **Appendix**. The same process was used to create solar profiles for the neighboring regions, whose locations are listed in **Table 50** in the **Appendix**. For future generic solar, a solar profile was created using the normalized final output of the existing tracking solar from the base case.

Wind Shapes

The 1980 through 2024 wind profiles for PNM were developed from historical wind data from the Casa Mesa, La Joya 1, La Joya 2, New Mexico Wind Energy Center (NMWEC), and Red Mesa wind farms, covering the period from April 1, 2021 through December 31, 2024. Synthetic profiles for each weather year were created using a peak load day matching approach: for each day in the weather year being constructed, the day with the closest peak load within five days before or after that calendar day was identified from the April 1, 2021 through December 31, 2024 historical data, and that day's wind profile was used. For example, July 16 in the 1994 profile was matched by examining each July 11 through July 21 day in the historical data, selecting the day with the closest peak load, and using that day's wind output. The resulting daily profiles were smoothed between days, and the final normalized profiles were used in SERVM.

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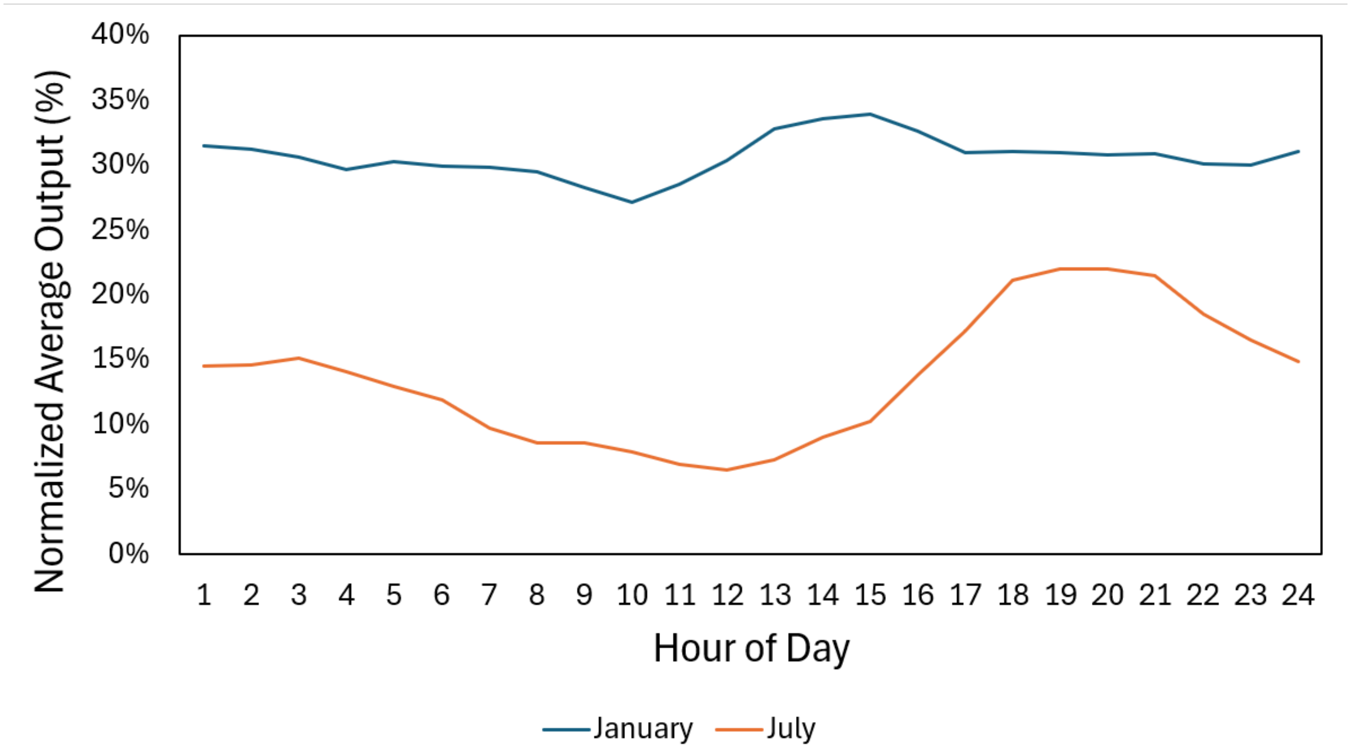
For the NMWEC profile, synthetic profiles were created for both the NMWEC and Casa Mesa sites and then summed, subject to a cap of 200 MW.

The PNM expansion wind profile was developed using the SERVM Wind Diversity Tool. This tool adjusts a region's wind generation profile so that the correlation between the wind output of two regions matches a target correlation, reflecting the diversity of wind resources across areas rather than assuming wind output is fully coincident or fully independent. The tool reaches the target by repeatedly swapping individual days within the same calendar month across years, keeping only those swaps that move the wind correlation closer to the target. The expansion wind profile was created from the La Joya 2 profile and adjusted to a 0.80 correlation with the La Joya 1 profile.

The average daily aggregate PNM wind output for the 2029 base case is shown for January and July in **Figure 13**.

Figure 13: Average PNM Base Case Wind Output



Wind profiles for the neighboring Arizona and PSCo regions were developed from historical hourly wind output for each region over 2019 through 2023. Each year's output was normalized to a 0 to 100 scale relative to that year's maximum hourly generation. Synthetic profiles for the 1980 through 2024 weather years were then created through load day matching against the SERVM synthetic load profiles: each synthetic day was paired with the historical days whose load most closely matched, and one of the closest matching days was selected at random to supply that day's normalized wind output. Multiple independent samplings were produced for each region and assigned across that region's wind units, so that units within a region draw on different random selections rather than an identical profile.

Conventional Thermal Resources and Resource Mix

Conventional thermal resources owned by PNM and contracted for via Power Purchase Agreements were modeled for the 2029 study year. These resources are economically committed and dispatched to load on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve regulation, spinning, and load following reserves assuming the minimum capacity level is less than the maximum capacity. The PNM base case system resource mix and respective Equivalent Forced Outage Rates (EFORs) are provided in **Table 15** below.

Table 15: 2029 Base Case Resource Mix and EFOR

Unit Type	Capacity (MW)	EFOR (%)
Battery	1,950	7.5%
Combined Cycle	425	5.5%
Combustion Turbine	786	2.7%
Demand Response	35	-
Geothermal	11	24.0%
Nuclear	288	2.0%
Solar	2,412	-
Steam Turbine Coal	200	20.0%
Steam Turbine Gas	145	9.1%
Wind[10]	1,408	-
Total	7,660	

EFORs are based on historical performance or expected future performance provided by PNM. Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical Generating Availability Data System (GADS) data from 2019–2024 are used to create an outage probability

[10] 50MW Casa Mesa wind is modeled within the NWWEC wind unit in SERVM due to real world transmission constraints, so the actual capacity of the system is 1,458MW, but it is modeled at 1,408MW.

distribution for each unit and SERVM randomly draws from this distribution for each unit to simulate outages. Units without historical data use data from similar units. Outage distributions were scaled to an expected EFOR provided by PNM. Outage distributions are constructed using the following variables.

Full Outage Modeling

- Time-to-Repair Hours
- Time-to-Fail Hours
- Start Probability

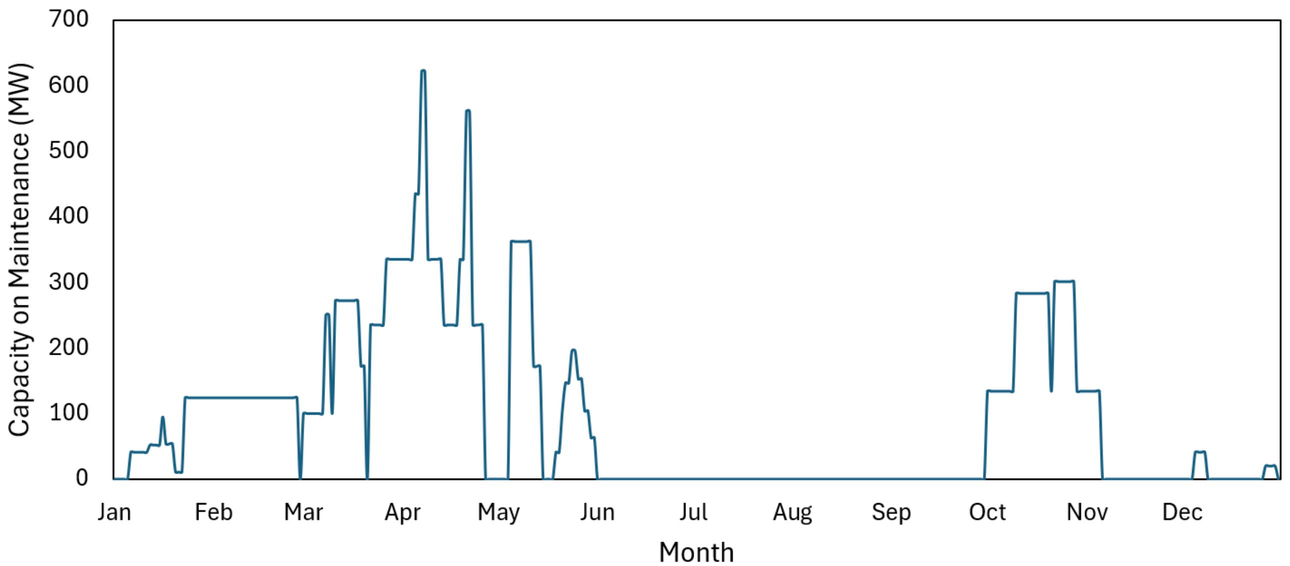
Partial Outage Modeling

- Partial Outage Time-to-Repair Hours
- Partial Outage Derate Percentage
- Partial Outage Time-to-Fail Hours

Planned Maintenance

Planned maintenance outage rates were applied to relevant units. These outage rates were provided by PNM where available and otherwise from publicly available data for the applicable technology. Before the simulation begins, SERVM's maintenance scheduler converts the outage rates into a target number of outage days per year and determines when those days are placed. Candidate windows are ranked by daily system load, by default using the average daily load across the selected net load shapes, and each unit's maintenance is assigned to the lowest load periods available in order to minimize stress on the system during outages. Units are scheduled in descending order of capacity, so that the largest generators, which have the greatest impact on reliability, are placed first into the lowest load windows. The result of this scheduling step is a fixed daily maintenance calendar for every unit. During the Monte Carlo simulation, SERVM enforces these calendars deterministically: each unit is removed from the commitment and dispatch queues on its maintenance start day and returned to service when its window ends. Throughout that period the unit contributes zero capacity with timing that has been deliberately placed in low load periods. The scheduled planned maintenance across the base case is shown in **Figure 14**.

Figure 14: PNM Planned Maintenance Schedule



Battery Modeling

Battery energy storage units were modeled with maximum combined output capacity (if applicable) and round-trip losses consistent with known project information and are economically scheduled and dispatched within SERVM. These resources typically charge during low net demand periods, subject to constraints, and are dispatched during net peak load periods. 4-hour storage units were modeled assuming an EFOR of 7.5%, which is an assumption based on a study conducted by E3[11] on the real-world first-year operation of utility-scale battery energy storage facilities located in California.

Demand Response Modeling

DR programs were modeled as resources in SERVM with specific contract limits. The sections below provide modeling characteristics for each of the modeled programs.

- **Battery Energy Storage Direct Load Control:** This program is modeled as two seasonal resources. PNM sends a dispatch signal that discharges (or curtails charging of) enrolled residential, commercial, and industrial batteries during an event. Events run one per day with a duration of two

[11] https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED

to four hours. The summer resource is limited to 35 call hours per year and the winter resource to 30 call hours per year.

- **Domestic Hot Water Heater Direct Load Control:** Modeled as two seasonal resources representing residential electric resistance and heat pump water heaters under one-way utility control. Each season allows up to 25 events per year at 4 hours per event, for 100 call hours per year, dispatched once per day. The summer and winter resources use the same event structure; the seasonal difference is in per participant load impact, which is carried in the capacity rather than the event parameters.
- **Peak Saver:** A year-round program for non-residential customers with peak load contributions of at least 150 kW, modeled as two seasonal resources with 4-hour events dispatched once per day. The summer resource is available June through September with up to 100 call hours per year, and the winter resource is available October through May with up to 300 call hours per year.
- **Power Saver:** A summer-only resource for residential and small-to-medium commercial customers, available June through September. It is dispatched once per day in 4-hour events for up to 100 call hours per year.
- **Behavioral:** A residential program modeled as a resource that is called on the roughly 11 highest peak days of the year. Events run 3 to 5 hours within the 1 p.m. to 7 p.m. peak window, one per day, for approximately 40 call hours per year.

Load Modifiers

Some of the units were modeled as Load Modifier (L) units to represent adjustments to the system load profile. In SERVM, Load Modifier units are used to capture expected changes in load composition. Each Load Modifier unit is associated with a weather station and a capacity multiplier table, which uses historical hourly weather data to determine the unit's hourly load shape. For this study, the hourly load shapes for the Load Modifier units were provided by PNM and used to represent the study-specific load adjustments and calibration assumptions. Energy Efficiency and Time of Day resources were modeled as L units in this analysis.

Ancillary Services

SERVM commits resources to meet energy needs plus ancillary service requirements, which are defined as SERVM model inputs. In real-world operation, these ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, which are served by units with automatic generation control (AGC) capability, spinning reserves, load following reserves, and quick start reserves. **Table 16** shows the definition of each ancillary service for this study. A loss of load event was recorded when there was insufficient generation to serve load plus the regulation up requirement.

Table 16: Ancillary Service Definitions

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	10 Minute Product served by units that have minimum load less than maximum load
Load Following Down Reserves	10 Minute Product served by units that have minimum load less than maximum load
Load Following Up Reserves	10 Minute Product served by units that have minimum load less than maximum load
Load Following Up Range Adder	Additional upward load-following reserve above the minimum Load Following Up Reserve requirement.
Load Following Min Up Reserves Target	Minimum additional upward load-following reserve maintained above the spinning reserve requirement.
Quick Start Reserves Requirement	Served by units that are offline and have quick start capability
Quick Start Reserves Target	Target amount of quick-start (non-spinning) reserve capacity maintained each hour.

For this study, these ancillary service requirements were applied to the PNM BA, with each requirement specified as a percentage of load. Regulation up and regulation down were each set at 6% of load, and a quick start reserves target of 4% of load was applied.

Results

Planning Reserve Margin and Existing ELCCs

The existing resource fleet was accredited on an ELCC basis using the methodologies described in the Study Methodology section. The Delta Method was applied to the existing wind, solar, battery storage, and demand-side resources, and a thermal ELCC analysis was used to accredit the conventional thermal fleet as described in the Executive Summary. The resulting ELCC values are shown below.

Table 17: Existing ELCCs

Category	ICAP (MW)	ELCC (%)
Battery	1,950	75%
Solar	2,412	19%
Wind	1,408	12%
Demand Response	35	59%

Table 18: Thermal ELCCs

Category	ICAP (MW)	ELCC (%)
Combined Cycle	425	92%
Combustion Turbine	786	98%
Nuclear	288	94%
Steam Turbine Coal	200	72%
Steam Turbine Gas	145	92%

The full accreditation is shown in **Table 19**.

Table 19: Resource Accreditation (Average ELCC by technology)

Unit Category	ICAP (MW)	ELCC (%)	Accreditation (MW)
Battery	1,950	75%	1,471
Combined Cycle	425	92%	393
Combustion Turbine	786	98%	774
Demand Response	35	59%	21
Geothermal	11	76%	8
Nuclear	288	94%	271
Solar	2,412	19%	458
Steam Turbine Coal	200	72%	143
Steam Turbine Gas	145	92%	133
Wind	1,408	12%	169
Total			**3,841**

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The resulting reserve margins are summarized below. At the base case peak load, the system carries an as-is reserve margin of 24.8%. This initial set of existing resources assumed additional gas resources PNM had identified in its 2029–2032 System Resources application filed with the NMPRC in mid-2026. PNM utilized generic gas resources to serve as placeholders until it determines actual resources that PNM intends to procure, following evaluation of RFP bids it plans to receive in the second half of 2026. Economic development load was added to calibrate the system to 0.1 LOLE, and each resource was accredited at its ELCC to determine the PRM. Calibrated to the 0.1 LOLE target, the PRM is 14.5%. This target PRM was then used as the basis for PNM's capacity expansion plans in the 2026 IRP.

Table 20: Reserve Margin Summary

Metric	Value
Total accredited capacity (MW)	3,841
Base case peak load (MW)	3,078
As-is reserve margin	24.8%
0.1 LOLE peak load (MW)	3,354
0.1 LOLE reserve margin	14.5%

The timing of the loss of load events and expected unserved energy from the base case calibrated to 0.1 LOLE are shown in **Table 21** and **Table 22** below. These tables represent the percentage of total loss of load hours (LOLH) and EUE found in the given hour-month combination. A value of 1%, for example, indicates that 1% of the total LOLH or EUE occurred in the given hour within the simulations.

Table 21: 2029 Base Case LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	-	0.1%	-	-	-	0.5%	0.1%	-	-	-	-	0.1%	**0.8%**
2	-	0.2%	-	-	-	0.3%	0.1%	-	-	-	-	0.1%	**0.6%**
3	-	0.2%	-	-	-	0.2%	-	-	-	-	-	0.1%	**0.5%**
4	-	0.4%	-	-	-	0.0%	-	-	-	-	-	0.2%	**0.6%**
5	-	0.5%	-	-	-	-	-	-	-	-	-	0.6%	**1.1%**
6	0.2%	1.6%	-	-	-	-	-	-	-	-	-	1.3%	**3.1%**
7	0.4%	4.1%	-	-	-	-	-	-	-	-	-	3.4%	**7.9%**
8	0.5%	5.3%	-	-	-	-	-	-	-	-	-	5.2%	**11.0%**
9	0.2%	1.9%	-	-	-	-	-	-	-	-	-	2.0%	**4.1%**
10	-	0.3%	-	-	-	-	-	-	-	-	-	0.5%	**0.8%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	0.0%	0.0%	-	-	-	-	**0.1%**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	0.0%	0.3%	0.0%	-	-	-	-	**0.4%**
18	-	-	-	-	-	-	0.7%	0.1%	0.0%	-	-	-	**0.8%**
19	-	-	-	-	-	8.8%	11.9%	2.2%	-	-	-	0.0%	**23.0%**
20	-	-	-	-	-	17.3%	16.5%	1.8%	-	-	-	0.0%	**35.6%**
21	-	0.0%	-	-	-	4.4%	1.9%	0.2%	-	-	-	0.2%	**6.7%**
22	-	0.0%	-	-	-	0.6%	0.3%	0.0%	-	-	-	0.3%	**1.2%**
23	-	0.0%	-	-	-	0.2%	0.1%	0.0%	-	-	-	0.3%	**0.7%**
24	-	0.0%	-	-	-	0.6%	0.1%	0.0%	-	-	-	0.3%	**1.1%**
Total	**1.3%**	**14.7%**	**-**	**-**	**-**	**33.0%**	**31.9%**	**4.3%**	**0.0%**	**-**	**-**	**14.7%**	**100.0%**

Table 22: 2029 Base Case EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	-	0.1%	-	-	-	0.6%	0.1%	-	-	-	-	0.2%	**1.0%**
2	-	0.2%	-	-	-	0.1%	0.0%	-	-	-	-	0.4%	**0.8%**
3	-	0.3%	-	-	-	0.0%	-	-	-	-	-	0.5%	**0.8%**
4	-	0.7%	-	-	-	0.0%	-	-	-	-	-	0.8%	**1.5%**
5	-	1.9%	-	-	-	-	-	-	-	-	-	1.8%	**3.7%**
6	0.2%	4.8%	-	-	-	-	-	-	-	-	-	4.8%	**9.8%**
7	1.2%	14.6%	-	-	-	-	-	-	-	-	-	12.7%	**28.5%**
8	1.7%	13.2%	-	-	-	-	-	-	-	-	-	13.1%	**28.0%**
9	0.2%	1.4%	-	-	-	-	-	-	-	-	-	1.9%	**3.5%**
10	-	0.0%	-	-	-	-	-	-	-	-	-	0.3%	**0.3%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	0.0%	0.0%	-	-	-	-	**0.0%**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	0.0%	0.0%	0.0%	-	-	-	-	**0.0%**
18	-	-	-	-	-	-	0.1%	0.0%	0.0%	-	-	-	**0.1%**
19	-	-	-	-	-	1.3%	1.9%	0.4%	-	-	-	0.1%	**3.7%**
20	-	-	-	-	-	6.0%	4.0%	0.5%	-	-	-	0.2%	**10.8%**
21	-	0.1%	-	-	-	1.3%	0.8%	0.1%	-	-	-	0.5%	**2.6%**
22	-	0.1%	-	-	-	0.2%	0.1%	0.1%	-	-	-	0.6%	**1.1%**
23	-	0.1%	-	-	-	0.9%	0.2%	0.0%	-	-	-	0.8%	**1.9%**
24	-	0.0%	-	-	-	1.4%	0.1%	0.0%	-	-	-	0.2%	**1.9%**
Total	**3.3%**	**37.5%**	**-**	**-**	**-**	**11.8%**	**7.5%**	**1.1%**	**0.0%**	**-**	**-**	**38.9%**	**100.0%**

As shown in the heat maps, approximately 70% of PNM's LOLH falls in the summer months. These events are concentrated in hours 19 and 20, when net load peaks as solar generation falls offline and load remains high. Conversely, approximately 80% of the EUE falls in the winter months, concentrated in the morning hours 6, 7, and 8. While LOLE is significantly more frequent in summer months, when PNM's load is highest, the most severe events fall in the winter months. PNM's winter events tend to be more severe in magnitude because they are related to PNM's energy limmited resources running out of energy due to prolonged periods of high demand without the ability to charge using solar generation through the night. PNM's summer LOLE is generally related to the lack of capacity to meet higher loads, while winter LOLE is generally related to the lack of energy available to charge storage through low renewable generation.

Transmission Sensitivity

An additional sensitivity was performed to evaluate the reliability benefit of increased summer import capability. In this sensitivity, the import capacity during the summer peak hours was doubled from 50 MW to 100 MW. The additional import allowance produced an approximate 40 MW reliability benefit, which translates to a reduction of roughly 1.4 percentage points in the PRM, from 14.5% to 13.1%.

The benefit is less than the full 50 MW increase in the import allowance. This indicates that during some of the risk hours the binding constraint is the availability of resources in neighboring regions rather than the import limit itself, so the additional import allowance is not always deliverable.

Incremental ELCCs

Incremental ELCC values were developed for solar, wind, 4HR storage, 8HR storage, PSH, DR, and energy efficiency using the methodology described in the Study Methodology section. The incremental ELCC values reflect the marginal accreditation of each technology as penetration increases. Solar and wind results are reported as standalone additions, while the storage results assume a solar buildout at a 2:1 solar-to-storage ratio. DR and energy efficiency were each evaluated at a single incremental level rather than across a range of penetrations. DR was evaluated at an incremental MW level of 50 MW and energy efficiency was evaluated at an incremental MW level of 100 MW.

Table 23: Incremental Solar ELCC

Incremental Solar (MW)	Average ELCC (%)	Tranche ELCC (%)
800	3%	3%
1,600	2%	<1%
2,400	1%	<1%
3,200	1%	<1%
4,000	1%	<1%

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Table 24: Incremental Wind ELCC

Incremental Wind (MW)	Average ELCC (%)	Tranche ELCC (%)
500	8%	8%
1,000	5%	2%

Table 25: Incremental Storage Tranche ELCC

Incremental Storage (MW)	4HR	8HR	PSH
400	42%	58%	74%
800	26%	42%	61%
1,200	22%	28%	43%
1,600	—	26%	37%
2,000	—	26%	38%

Table 26: Incremental Demand Response and Energy Efficiency ELCC

Resource	ELCC (%)
Demand Response	63%
Energy Efficiency	50%

Portfolio Reliability Verification

PNM developed candidate expansion portfolios for the CTP and HEG futures across 2036, 2040, and 2045 study years, along with a stakeholder-proposed scenario portfolio. Each portfolio was simulated in SERVM to verify its reliability against the 0.1 LOLE target. The portfolio compositions are presented first, followed by the reliability results.

Table 27: CTP Portfolio

Technology	2036	2040	2045
Solar	2,910	3,053	2,440
Wind	1,356	1,356	800
Short Duration Storage	2,250	2,285	2,248
Long Duration Storage	100	100	100
Combined Cycle	425	425	—
Combustion Turbine	654	487	338
Steam Turbine	146	146	—
Linear Generator	—	120	160
Nuclear	288	288	1,310
Geothermal	11	11	—
Demand Response	45	49	52
Energy Efficiency	403	454	377
Load Forecast	**3,583**	**3,711**	**3,814**

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Table 28: HEG Portfolio

Technology	2036	2040	2045
Solar	3,460	3,623	3,049
Wind	1,555	1,555	999
Short Duration Storage	2,406	2,406	2,345
Long Duration Storage	300	300	300
Pumped Storage Hydro	100	100	100
Combined Cycle	425	425	—
Combustion Turbine	654	487	338
Steam Turbine	146	146	—
Linear Generator	—	280	440
Nuclear	288	288	1,310
Geothermal	11	11	—
Demand Response	45	49	52
Energy Efficiency	403	454	377
Load Forecast	**4,048**	**4,326**	**4,609**

Table 29: Stakeholder Proposed Scenario Portfolio

Technology	2036	2040	2045
Solar	2,524	2,425	1,875
Wind	1,356	1,356	1,062
Short Duration Storage	2,273	2,273	1,947
Long Duration Storage	—	—	200
Combined Cycle	425	425	—
Combustion Turbine	482	315	—
Steam Turbine	146	146	—
Nuclear	288	288	1,310
Geothermal	361	361	350
Demand Response	174	258	363
Energy Efficiency	403	454	377
Load Forecast	**3,488**	**3,557**	**3,673**

Each portfolio was simulated across the 2036, 2040, and 2045 study years to determine its LOLE relative to the 0.1 target. For the CTP and HEG portfolios, the incremental 4HR storage adjustment required to bring each portfolio to 0.1 LOLE was also determined. A negative adjustment indicates the portfolio was over-reliable and storage could be removed, and a positive adjustment indicates additional storage was needed.

Table 30: CTP Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	38	18.8%	−170
2040	0.23	221	13.6%	+285
2045	0.08	99	14.2%	−90

In 2036 the CTP portfolio exceeds the reserve margin target, at 18.8% against the 14.5% target; the portfolio determination in the expansion planning model allows the reserve margin to exceed the PRM where doing so minimizes 20-year net present value. In 2040 the portfolio is underbuilt relative to the target, at 13.6%. In 2045, the estimated reserve margin implies a higher LOLE than the results show. This result indicates a minor disconnect between the ELCCs and the actual reliability contribution of resources. In 2045, as significant nuclear capacity is added and existing wind and solar retire, the average reliability contribution of the remaining renewable and storage resources likely experiences a small increase, leading to the underestimation of the total firm capacity of the portfolio. This effect also occurs in the HEG portfolio for the 2045 study year.

Table 31: HEG Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	34	18.6%	−230
2040	0.11	80	15.2%	+20
2045	0.03	19	15.1%	−190

The HEG portfolio follows a similar pattern, exceeding the reserve margin target in 2036 at 18.6%, and sitting near the target in 2040 at 15.2% and 2045 at 15.1%.

Heat maps illustrating the timing and severity of each portfolio and study year combination are provided below. In the 2029 base case, LOLH and EUE point in opposite seasonal directions. LOLH is predominantly a summer risk (69% summer, 31% winter), while EUE is already weighted toward winter (20% summer, 80% winter); summer events are frequent but shallow, and winter events are fewer but deeper. The CTP portfolio sees both metrics decisively move into winter with later study years. LOLH inverts from being led by summer to being led by winter by the 2036 study year (24% summer, 76% winter) and becomes almost entirely a winter risk by 2040 (2% summer, 98% winter), holding through 2045. EUE moves from 80% winter in the base case to 94% by 2036 and roughly 99% by 2040, so effectively all unserved energy becomes a winter event.

The HEG portfolio also shifts EUE risk toward winter, but less completely and not monotonically. LOLH is led by winter in 2036 (62% winter) and 2040 (79% winter) but reverses back slightly to summer by 2045 (61% summer, 39% winter). In contrast, EUE stays overwhelmingly winter across all study years (92%, 95%, and 88% winter in 2036, 2040, and 2045). The bias of more LOLH summer capacity risk in the HEG portfolio is largely due to the increase in loads which adds more summer peak load compared to winter peak load.

Reliability risk also moves between winter months. In CTP, February and December hold 87% of EUE in 2036. By 2045, January alone holds 84.6% and December falls to 4.8%. HEG moves the same direction: February and December hold 89% in 2036, and January reaches 55.3% by 2045. Net load changes help explain these shifts. As loads increase and the installed capacities of wind and solar resources change, January increases its share of each study year's top 5% of net load energy days in both portfolios — from 10.7% to 20.7% in CTP and 11.3% to 16.7% in HEG. December's share stays flat in CTP but rises in HEG, consistent with December retaining EUE in HEG only.

Table 32: CTP 2036 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.4%	-	-	-	0.9%	0.1%	0.1%	-	-	-	0.8%	**2.4%**
2	0.2%	0.4%	-	-	-	0.8%	0.0%	0.2%	-	-	-	0.3%	**2.0%**
3	0.2%	1.0%	-	-	-	0.5%	0.1%	0.2%	-	-	-	0.6%	**2.6%**
4	0.3%	1.4%	-	-	-	0.4%	-	0.2%	-	-	-	0.9%	**3.2%**
5	0.4%	2.7%	-	-	-	0.4%	-	0.1%	-	-	-	1.3%	**5.0%**
6	0.4%	5.1%	-	-	-	0.2%	0.0%	0.1%	-	-	-	2.9%	**8.8%**
7	1.0%	9.3%	-	-	-	-	0.0%	-	-	-	-	6.8%	**17.1%**
8	1.3%	10.4%	-	-	-	-	-	-	-	-	-	9.8%	**21.6%**
9	0.3%	3.0%	-	-	-	-	-	-	-	-	-	2.7%	**6.0%**
10	-	0.3%	-	-	-	-	-	-	-	-	-	0.5%	**0.8%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
18	0.0%	-	-	-	-	-	-	0.1%	-	-	-	0.1%	**0.2%**
19	0.0%	0.0%	-	-	-	1.7%	2.6%	0.9%	-	-	-	0.1%	**5.3%**
20	0.0%	0.1%	-	-	-	4.0%	4.8%	1.0%	-	-	-	0.6%	**10.6%**
21	0.1%	0.1%	-	-	-	1.9%	1.0%	0.0%	-	-	-	1.3%	**4.5%**
22	0.2%	0.2%	-	-	-	0.3%	0.1%	-	-	-	-	1.9%	**2.7%**
23	0.2%	0.2%	-	-	-	0.2%	0.0%	-	-	-	-	2.6%	**3.3%**
24	0.2%	0.2%	-	-	-	0.6%	0.0%	0.0%	-	-	-	2.8%	**3.9%**
Total	**5.2%**	**34.9%**	**-**	**-**	**-**	**11.8%**	**8.8%**	**3.0%**	**-**	**-**	**-**	**36.3%**	**100.0%**

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Table 33: CTP 2036 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	0.3%	-	-	-	1.2%	0.1%	0.1%	-	-	-	0.5%	2.3%
2	0.1%	0.5%	-	-	-	0.6%	0.1%	0.3%	-	-	-	0.5%	2.1%
3	0.1%	0.8%	-	-	-	0.1%	0.0%	0.3%	-	-	-	0.7%	2.1%
4	0.2%	1.8%	-	-	-	0.1%	-	0.1%	-	-	-	1.2%	3.4%
5	0.6%	3.5%	-	-	-	0.1%	-	0.0%	-	-	-	2.3%	6.7%
6	0.9%	8.2%	-	-	-	0.0%	0.0%	0.0%	-	-	-	4.9%	14.1%
7	1.4%	15.8%	-	-	-	-	0.0%	-	-	-	-	11.2%	28.5%
8	1.5%	10.2%	-	-	-	-	-	-	-	-	-	9.9%	21.6%
9	0.1%	0.8%	-	-	-	-	-	-	-	-	-	1.1%	2.0%
10	-	0.0%	-	-	-	-	-	-	-	-	-	0.1%	0.1%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
18	0.0%	-	-	-	-	-	-	0.0%	-	-	-	0.1%	0.1%
19	0.1%	0.0%	-	-	-	0.1%	0.1%	0.1%	-	-	-	0.2%	0.5%
20	0.1%	0.1%	-	-	-	0.6%	0.6%	0.1%	-	-	-	0.7%	2.1%
21	0.1%	0.2%	-	-	-	0.3%	0.2%	0.0%	-	-	-	2.1%	2.8%
22	0.3%	0.5%	-	-	-	0.0%	0.0%	-	-	-	-	2.8%	3.6%
23	0.4%	0.6%	-	-	-	0.1%	0.0%	-	-	-	-	3.2%	4.4%
24	0.4%	0.4%	-	-	-	0.8%	0.1%	0.0%	-	-	-	1.8%	3.6%
Total	**6.5%**	**43.9%**	**-**	**-**	**-**	**4.1%**	**1.1%**	**1.0%**	**-**	**-**	**-**	**43.4%**	**100.0%**

Table 34: CTP 2040 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.4%	0.9%	-	-	-	0.1%	0.0%	-	-	-	-	2.6%	4.0%
2	0.3%	1.0%	-	-	-	0.2%	0.1%	-	-	-	-	0.8%	2.3%
3	0.3%	1.1%	-	-	-	0.2%	0.0%	-	-	-	-	1.3%	2.9%
4	0.4%	1.3%	-	-	-	0.1%	-	-	-	-	-	1.5%	3.5%
5	0.7%	2.1%	-	-	-	0.2%	-	-	-	-	-	2.8%	5.7%
6	1.0%	3.5%	-	-	-	0.1%	-	-	-	-	-	5.2%	9.8%
7	1.8%	6.6%	-	-	-	-	-	-	-	-	-	10.1%	18.5%
8	2.4%	8.3%	-	-	-	-	-	-	-	-	-	13.3%	24.1%
9	0.4%	2.8%	-	-	-	-	-	-	-	-	-	3.6%	6.8%
10	0.0%	0.3%	-	-	-	-	-	-	-	-	-	0.5%	0.8%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	0.0%	-	-	-	-	0.0%
17	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
18	-	-	-	-	-	-	-	-	-	-	-	0.2%	0.2%
19	0.0%	0.0%	-	-	-	0.0%	0.1%	0.1%	-	-	-	0.5%	0.8%
20	0.2%	0.0%	-	-	-	0.1%	0.2%	0.1%	-	-	-	1.1%	1.8%
21	0.2%	0.1%	-	-	-	0.1%	-	-	-	-	-	2.5%	2.9%
22	0.4%	0.2%	-	-	-	-	-	-	-	-	-	3.2%	3.8%
23	0.5%	0.3%	-	-	-	-	-	0.1%	-	-	-	4.6%	5.5%
24	0.6%	0.6%	-	-	-	0.1%	-	0.1%	-	-	-	5.1%	6.5%
Total	**9.7%**	**29.4%**	**-**	**-**	**-**	**1.2%**	**0.4%**	**0.4%**	**-**	**-**	**-**	**59.0%**	**100.0%**

Table 35: CTP 2040 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.5%	-	-	-	0.1%	0.0%	-	-	-	-	0.7%	**1.5%**
2	0.1%	0.6%	-	-	-	0.1%	0.0%	-	-	-	-	0.9%	**1.8%**
3	0.2%	0.8%	-	-	-	0.1%	0.0%	-	-	-	-	1.2%	**2.3%**
4	0.4%	1.2%	-	-	-	0.0%	-	-	-	-	-	1.7%	**3.3%**
5	0.6%	2.0%	-	-	-	0.0%	-	-	-	-	-	3.3%	**6.0%**
6	1.1%	4.4%	-	-	-	0.0%	-	-	-	-	-	6.9%	**12.5%**
7	2.3%	9.2%	-	-	-	-	-	-	-	-	-	15.0%	**26.5%**
8	2.1%	7.4%	-	-	-	-	-	-	-	-	-	12.7%	**22.1%**
9	0.1%	0.5%	-	-	-	-	-	-	-	-	-	0.9%	**1.5%**
10	0.0%	0.0%	-	-	-	-	-	-	-	-	-	0.1%	**0.1%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	0.0%	-	-	-	-	**0.0%**
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
18	-	-	-	-	-	-	-	-	-	-	-	0.2%	**0.2%**
19	0.0%	0.0%	-	-	-	0.0%	0.0%	0.0%	-	-	-	0.7%	**0.7%**
20	0.1%	0.1%	-	-	-	0.0%	0.0%	0.0%	-	-	-	1.6%	**1.8%**
21	0.3%	0.1%	-	-	-	0.0%	-	-	-	-	-	3.3%	**3.8%**
22	0.6%	0.3%	-	-	-	-	-	-	-	-	-	4.3%	**5.2%**
23	0.7%	0.5%	-	-	-	-	-	0.1%	-	-	-	5.2%	**6.4%**
24	0.6%	0.6%	-	-	-	0.0%	-	0.0%	-	-	-	3.0%	**4.2%**
Total	**9.5%**	**28.3%**	**-**	**-**	**-**	**0.3%**	**0.1%**	**0.1%**	**-**	**-**	**-**	**61.7%**	**100.0%**

Table 36: CTP 2045 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	1.4%	0.5%	-	-	-	0.0%	0.0%	-	-	-	-	0.2%	**2.1%**
2	1.8%	0.4%	-	-	-	-	-	-	-	-	-	0.1%	**2.3%**
3	2.3%	0.4%	-	-	-	-	-	-	-	-	-	0.1%	**2.9%**
4	3.3%	0.5%	-	-	-	-	-	-	-	-	-	0.3%	**4.1%**
5	5.1%	0.9%	-	-	-	-	-	-	-	-	-	0.4%	**6.3%**
6	8.2%	1.4%	-	-	-	-	-	-	-	-	-	0.6%	**10.3%**
7	15.1%	2.7%	-	-	-	-	-	-	-	-	-	1.3%	**19.1%**
8	20.5%	3.6%	-	-	-	-	-	-	-	-	-	1.7%	**25.9%**
9	9.6%	1.7%	-	-	-	-	-	-	-	-	-	0.2%	**11.5%**
10	1.3%	0.2%	-	-	-	-	-	-	-	-	-	0.1%	**1.5%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	-	-	-	-	-	**-**
18	0.1%	-	-	-	-	-	-	-	-	-	-	-	**0.1%**
19	0.2%	-	-	-	-	0.9%	0.7%	0.2%	-	-	-	-	**2.0%**
20	0.3%	-	-	-	-	2.1%	2.4%	0.4%	-	-	-	0.1%	**5.3%**
21	0.5%	-	-	-	-	0.3%	0.3%	0.0%	-	-	-	0.2%	**1.3%**
22	0.9%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.3%	**1.3%**
23	1.3%	0.2%	-	-	-	0.0%	-	-	-	-	-	0.3%	**1.9%**
24	1.4%	0.3%	-	-	-	0.0%	-	-	-	-	-	0.3%	**2.1%**
Total	**73.5%**	**12.9%**	**-**	**-**	**-**	**3.4%**	**3.4%**	**0.6%**	**-**	**-**	**-**	**6.1%**	**100.0%**

3000 Riverchase Galleria
Suite 575
Hoover, AL 35244

Table 37: CTP 2045 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.9%	0.2%	-	-	-	0.0%	0.0%	-	-	-	-	0.1%	**1.1%**
2	1.3%	0.1%	-	-	-	-	-	-	-	-	-	0.1%	**1.5%**
3	2.0%	0.2%	-	-	-	-	-	-	-	-	-	0.1%	**2.4%**
4	3.6%	0.3%	-	-	-	-	-	-	-	-	-	0.1%	**4.0%**
5	6.5%	0.6%	-	-	-	-	-	-	-	-	-	0.2%	**7.4%**
6	12.8%	1.5%	-	-	-	-	-	-	-	-	-	0.6%	**14.9%**
7	24.5%	3.2%	-	-	-	-	-	-	-	-	-	1.4%	**29.1%**
8	25.5%	3.2%	-	-	-	-	-	-	-	-	-	1.1%	**29.8%**
9	3.2%	0.2%	-	-	-	-	-	-	-	-	-	0.1%	**3.5%**
10	0.1%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	**0.1%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	-	-	-	-	-	**-**
18	0.0%	-	-	-	-	-	-	-	-	-	-	-	**0.0%**
19	0.1%	-	-	-	-	0.0%	0.0%	0.0%	-	-	-	-	**0.2%**
20	0.3%	-	-	-	-	0.1%	0.2%	0.0%	-	-	-	0.0%	**0.7%**
21	0.5%	-	-	-	-	0.0%	0.0%	0.0%	-	-	-	0.1%	**0.7%**
22	0.9%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.3%	**1.3%**
23	1.2%	0.2%	-	-	-	0.0%	-	-	-	-	-	0.3%	**1.8%**
24	1.1%	0.2%	-	-	-	0.0%	-	-	-	-	-	0.2%	**1.6%**
Total	**84.6%**	**10.1%**	**-**	**-**	**-**	**0.2%**	**0.2%**	**0.0%**	**-**	**-**	**-**	**4.8%**	**100.0%**

Table 38: HEG 2036 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	0.5%	-	-	-	0.8%	0.1%	-	-	-	-	0.6%	**2.0%**
2	0.1%	0.4%	-	-	-	0.9%	0.0%	-	-	-	-	0.5%	**1.8%**
3	0.1%	0.5%	-	-	-	0.8%	0.1%	-	-	-	-	0.7%	**2.1%**
4	0.1%	0.9%	-	-	-	0.8%	0.1%	-	-	-	-	0.9%	**2.8%**
5	0.1%	2.3%	-	-	-	0.7%	0.0%	-	-	-	-	1.4%	**4.6%**
6	0.1%	4.2%	-	-	-	0.2%	0.0%	-	-	-	-	2.1%	**6.6%**
7	0.3%	7.6%	-	-	-	-	-	-	-	-	-	4.7%	**12.6%**
8	0.5%	8.8%	-	-	-	-	-	-	-	-	-	6.0%	**15.3%**
9	0.2%	2.0%	-	-	-	-	-	-	-	-	-	1.7%	**3.9%**
10	0.0%	0.0%	-	-	-	-	-	-	-	-	-	0.1%	**0.2%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	0.0%	-	-	-	0.0%	**0.0%**
18	0.0%	0.1%	-	-	-	-	-	0.0%	-	-	-	0.3%	**0.5%**
19	0.0%	0.1%	-	-	-	3.1%	4.2%	1.5%	-	-	-	0.5%	**9.5%**
20	0.1%	0.1%	-	-	-	7.9%	7.8%	2.3%	-	-	-	1.3%	**19.5%**
21	0.1%	0.1%	-	-	-	3.8%	1.4%	0.5%	-	-	-	1.7%	**7.6%**
22	0.1%	0.2%	-	-	-	0.1%	0.2%	0.1%	-	-	-	2.2%	**2.9%**
23	0.2%	0.4%	-	-	-	0.1%	0.0%	-	-	-	-	2.9%	**3.6%**
24	0.2%	0.6%	-	-	-	0.5%	0.1%	-	-	-	-	3.1%	**4.5%**
Total	**2.2%**	**28.8%**	**-**	**-**	**-**	**19.7%**	**14.0%**	**4.3%**	**-**	**-**	**-**	**30.9%**	**100.0%**

3000 Riverchase Galleria
Suite 575
Hoover, AL 35244

Table 39: HEG 2036 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	0.2%	-	-	-	1.4%	0.1%	-	-	-	-	0.7%	**2.5%**
2	0.0%	0.3%	-	-	-	0.9%	0.0%	-	-	-	-	0.8%	**2.0%**
3	0.0%	0.4%	-	-	-	0.3%	0.1%	-	-	-	-	1.1%	**1.9%**
4	0.0%	1.1%	-	-	-	0.2%	0.1%	-	-	-	-	1.6%	**3.0%**
5	0.1%	3.0%	-	-	-	0.3%	0.0%	-	-	-	-	2.9%	**6.3%**
6	0.1%	7.1%	-	-	-	0.0%	0.0%	-	-	-	-	4.9%	**12.2%**
7	0.5%	14.5%	-	-	-	-	-	-	-	-	-	9.2%	**24.2%**
8	0.7%	10.1%	-	-	-	-	-	-	-	-	-	8.6%	**19.5%**
9	0.1%	0.4%	-	-	-	-	-	-	-	-	-	0.8%	**1.3%**
10	0.0%	0.0%	-	-	-	-	-	-	-	-	-	0.1%	**0.1%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	0.0%	-	-	-	0.0%	**0.0%**
18	0.0%	0.0%	-	-	-	-	0.0%	0.0%	-	-	-	0.1%	**0.1%**
19	0.1%	0.1%	-	-	-	0.1%	0.3%	0.2%	-	-	-	1.2%	**1.9%**
20	0.1%	0.3%	-	-	-	1.1%	1.1%	0.4%	-	-	-	2.5%	**5.4%**
21	0.2%	0.5%	-	-	-	0.3%	0.2%	0.1%	-	-	-	4.2%	**5.4%**
22	0.3%	0.7%	-	-	-	0.0%	0.0%	0.0%	-	-	-	3.9%	**4.9%**
23	0.3%	0.8%	-	-	-	0.2%	0.0%	-	-	-	-	3.9%	**5.3%**
24	0.3%	0.6%	-	-	-	0.9%	0.1%	-	-	-	-	1.9%	**3.9%**
Total	**3.0%**	**40.2%**	**-**	**-**	**-**	**5.7%**	**2.0%**	**0.6%**	**-**	**-**	**-**	**48.6%**	**100.0%**

Table 40: HEG 2040 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	1.2%	-	-	-	0.8%	0.2%	-	-	-	-	0.5%	**2.8%**
2	0.0%	0.7%	-	-	-	0.6%	0.0%	-	-	-	-	0.4%	**1.8%**
3	0.0%	1.0%	-	-	-	0.5%	0.0%	0.0%	-	-	-	0.7%	**2.2%**
4	0.1%	1.4%	-	-	-	0.6%	0.0%	0.0%	-	-	-	0.7%	**2.9%**
5	0.1%	2.5%	-	-	-	0.4%	0.0%	0.0%	-	-	-	1.0%	**4.1%**
6	0.2%	4.7%	-	-	-	0.1%	-	-	-	-	-	2.1%	**7.1%**
7	0.6%	9.2%	-	-	-	-	-	-	-	-	-	5.2%	**15.0%**
8	0.8%	10.6%	-	-	-	-	-	-	-	-	-	6.8%	**18.1%**
9	0.2%	2.2%	-	-	-	-	-	-	-	-	-	2.1%	**4.5%**
10	-	-	-	-	-	-	-	-	-	-	-	0.3%	**0.3%**
11	-	-	-	-	-	-	-	-	-	-	-	0.1%	**0.1%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	-	-	-	-	0.1%	**0.1%**
18	-	0.1%	-	-	-	-	-	-	0.1%	-	-	0.2%	**0.4%**
19	-	0.1%	-	-	-	1.7%	2.1%	0.6%	-	-	-	0.7%	**5.2%**
20	0.0%	0.3%	-	-	-	3.8%	4.5%	1.1%	-	-	-	1.8%	**11.6%**
21	0.1%	0.2%	-	-	-	1.8%	0.6%	0.2%	-	-	-	3.2%	**6.1%**
22	0.1%	0.5%	-	-	-	0.1%	-	0.0%	-	-	-	3.9%	**4.7%**
23	0.1%	1.0%	-	-	-	0.3%	-	-	-	-	-	4.9%	**6.3%**
24	0.2%	1.1%	-	-	-	0.6%	0.1%	-	-	-	-	4.7%	**6.8%**
Total	**2.6%**	**36.8%**	**-**	**-**	**-**	**11.6%**	**7.5%**	**2.0%**	**0.1%**	**-**	**-**	**39.4%**	**100.0%**

Table 41: HEG 2040 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.0%	0.5%	-	-	-	0.8%	0.1%	-	-	-	-	0.4%	1.8%
2	0.0%	0.5%	-	-	-	0.4%	0.1%	-	-	-	-	0.5%	1.3%
3	0.0%	0.3%	-	-	-	0.1%	0.0%	0.0%	-	-	-	0.6%	1.2%
4	0.1%	0.9%	-	-	-	0.1%	0.0%	0.0%	-	-	-	1.1%	2.1%
5	0.1%	3.4%	-	-	-	0.1%	0.0%	0.0%	-	-	-	1.6%	5.2%
6	0.2%	7.2%	-	-	-	0.0%	-	-	-	-	-	3.4%	10.8%
7	0.7%	15.1%	-	-	-	-	-	-	-	-	-	8.9%	24.7%
8	0.9%	10.2%	-	-	-	-	-	-	-	-	-	8.4%	19.5%
9	0.0%	0.2%	-	-	-	-	-	-	-	-	-	0.6%	0.8%
10	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
18	-	0.0%	-	-	-	-	-	-	0.0%	-	-	0.3%	0.3%
19	-	0.1%	-	-	-	0.1%	0.1%	0.0%	-	-	-	1.1%	1.4%
20	0.0%	0.2%	-	-	-	0.6%	0.5%	0.2%	-	-	-	3.2%	4.6%
21	0.1%	0.3%	-	-	-	0.2%	0.0%	0.0%	-	-	-	6.2%	6.8%
22	0.1%	0.8%	-	-	-	0.0%	-	0.0%	-	-	-	6.3%	7.2%
23	0.1%	1.7%	-	-	-	0.3%	-	-	-	-	-	5.5%	7.6%
24	0.2%	1.4%	-	-	-	0.9%	0.1%	-	-	-	-	1.7%	4.3%
Total	**2.6%**	**42.7%**	**-**	**-**	**-**	**3.7%**	**0.9%**	**0.3%**	**0.0%**	**-**	**-**	**49.8%**	**100.0%**

Table 42: HEG 2045 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.2%	-	-	-	0.2%	0.0%	-	-	-	-	0.4%	1.0%
2	0.3%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.2%	0.6%
3	0.5%	0.1%	-	-	-	-	-	-	-	-	-	0.3%	0.9%
4	0.7%	0.1%	-	-	-	-	-	-	-	-	-	0.4%	1.2%
5	1.3%	0.4%	-	-	-	-	-	-	-	-	-	0.3%	2.1%
6	2.5%	1.0%	-	-	-	-	-	-	-	-	-	0.5%	4.0%
7	4.7%	2.2%	-	-	-	-	-	-	-	-	-	1.1%	8.1%
8	6.6%	2.8%	-	-	-	-	-	-	-	-	-	1.4%	10.8%
9	3.3%	0.8%	-	-	-	-	-	-	-	-	-	0.3%	4.3%
10	0.5%	-	-	-	-	-	-	-	-	-	-	0.2%	0.7%
11	0.1%	-	-	-	-	-	-	-	-	-	-	-	0.1%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
18	-	0.1%	-	-	-	-	0.0%	0.1%	-	-	-	0.1%	0.3%
19	-	0.1%	-	-	-	9.2%	8.0%	2.6%	-	-	-	0.1%	20.0%
20	0.1%	0.1%	-	-	-	15.9%	15.4%	3.0%	-	-	-	0.3%	34.7%
21	0.2%	0.0%	-	-	-	3.5%	2.0%	0.2%	-	-	-	0.6%	6.6%
22	0.3%	0.2%	-	-	-	0.0%	0.0%	-	-	-	-	0.8%	1.3%
23	0.3%	0.2%	-	-	-	0.0%	0.0%	-	-	-	-	1.0%	1.5%
24	0.3%	0.3%	-	-	-	0.2%	0.0%	-	-	-	-	1.0%	1.8%
Total	**21.9%**	**8.6%**	**-**	**-**	**-**	**29.1%**	**25.6%**	**6.0%**	**-**	**-**	**-**	**8.9%**	**100.0%**

Table 43: HEG 2045 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.0%	-	-	-	0.1%	0.0%	-	-	-	-	0.2%	**0.6%**
2	0.3%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.2%	**0.5%**
3	0.7%	0.0%	-	-	-	-	-	-	-	-	-	0.3%	**1.0%**
4	1.6%	0.0%	-	-	-	-	-	-	-	-	-	0.3%	**1.9%**
5	3.1%	0.2%	-	-	-	-	-	-	-	-	-	0.4%	**3.8%**
6	7.9%	2.0%	-	-	-	-	-	-	-	-	-	0.8%	**10.7%**
7	18.2%	5.9%	-	-	-	-	-	-	-	-	-	2.2%	**26.3%**
8	18.9%	5.3%	-	-	-	-	-	-	-	-	-	2.2%	**26.3%**
9	2.5%	0.1%	-	-	-	-	-	-	-	-	-	0.5%	**3.1%**
10	0.1%	-	-	-	-	-	-	-	-	-	-	0.1%	**0.2%**
11	0.0%	-	-	-	-	-	-	-	-	-	-	-	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
18	-	0.0%	-	-	-	-	0.0%	0.0%	-	-	-	0.1%	**0.1%**
19	-	0.0%	-	-	-	1.1%	0.6%	0.4%	-	-	-	0.3%	**2.4%**
20	0.1%	0.0%	-	-	-	4.7%	2.5%	0.9%	-	-	-	0.8%	**9.0%**
21	0.2%	0.0%	-	-	-	0.8%	0.3%	0.0%	-	-	-	2.2%	**3.5%**
22	0.6%	0.5%	-	-	-	0.0%	0.1%	-	-	-	-	2.9%	**4.1%**
23	0.6%	0.9%	-	-	-	0.0%	0.1%	-	-	-	-	2.4%	**4.0%**
24	0.3%	0.5%	-	-	-	0.4%	0.1%	-	-	-	-	1.2%	**2.4%**
Total	**55.3%**	**15.6%**	**-**	**-**	**-**	**7.0%**	**3.6%**	**1.3%**	**-**	**-**	**-**	**17.2%**	**100.0%**

In 2036 the stakeholder-proposed scenario portfolio exceeds the reserve margin target, at 25.0%. In 2040, the LOLE of 0.30 is higher than the estimated reserve margin of 17.5% would suggest, reflecting an overstatement of the DR ELCC as well as storage ELCC because the portfolio has less solar energy to charge the storage than the CTP 2040 portfolio. In 2045, the scenario meets the 0.1 LOLE target on an estimated reserve margin of 11.9%, well below the 14.5% PRM, reflecting the same modest 2045 understatement of firm capacity described for the CTP and HEG portfolios above. Results are summarized in **Table 44**.

Table 44: Stakeholder Proposed Scenario Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)
2036	0.01	5	25.0%
2040	0.30	329	17.5%
2045	0.10	65	11.9%

Resiliency Analysis

Portfolio Resiliency

The CTP and HEG portfolios calibrated to 0.1 LOLE were simulated for the selected summer and winter extreme weather years across the 2036, 2040, and 2045 study years. An additional island sensitivity was also conducted to understand the system's resiliency under extreme conditions with no external assistance. The resulting weekly EUE is shown below for each portfolio and study year. Weekly dispatch charts for all portfolio, study year, season, and interconnected/islanded combinations are provided in the **Appendix**; selected charts are reproduced in this section to illustrate the discussion.

Table 45: Summer Resiliency Results

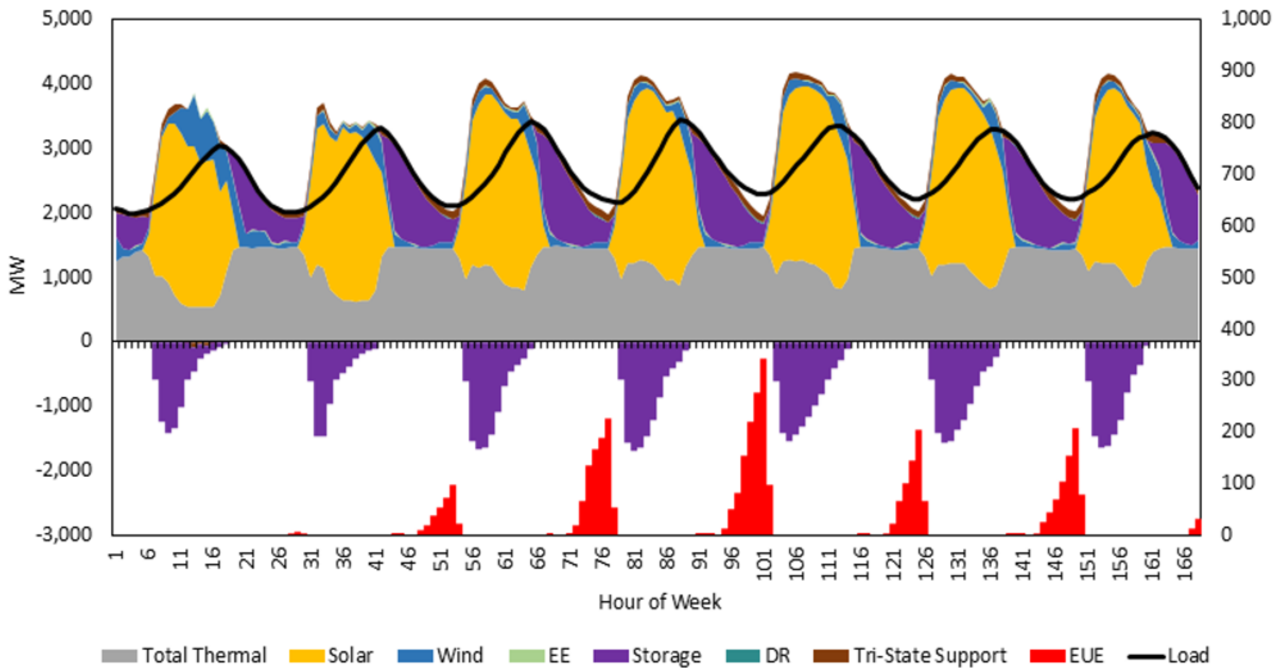
Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	6	3,758
CTP	2040	1	4,383
CTP	2045	4	2,509
HEG	2036	33	3,892
HEG	2040	13	3,596
HEG	2045	7	1,152

Table 46: Winter Resiliency Results

Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	259	9,259
CTP	2040	614	10,237
CTP	2045	76	3,823
HEG	2036	252	17,187
HEG	2040	528	6,061
HEG	2045	54	2,470

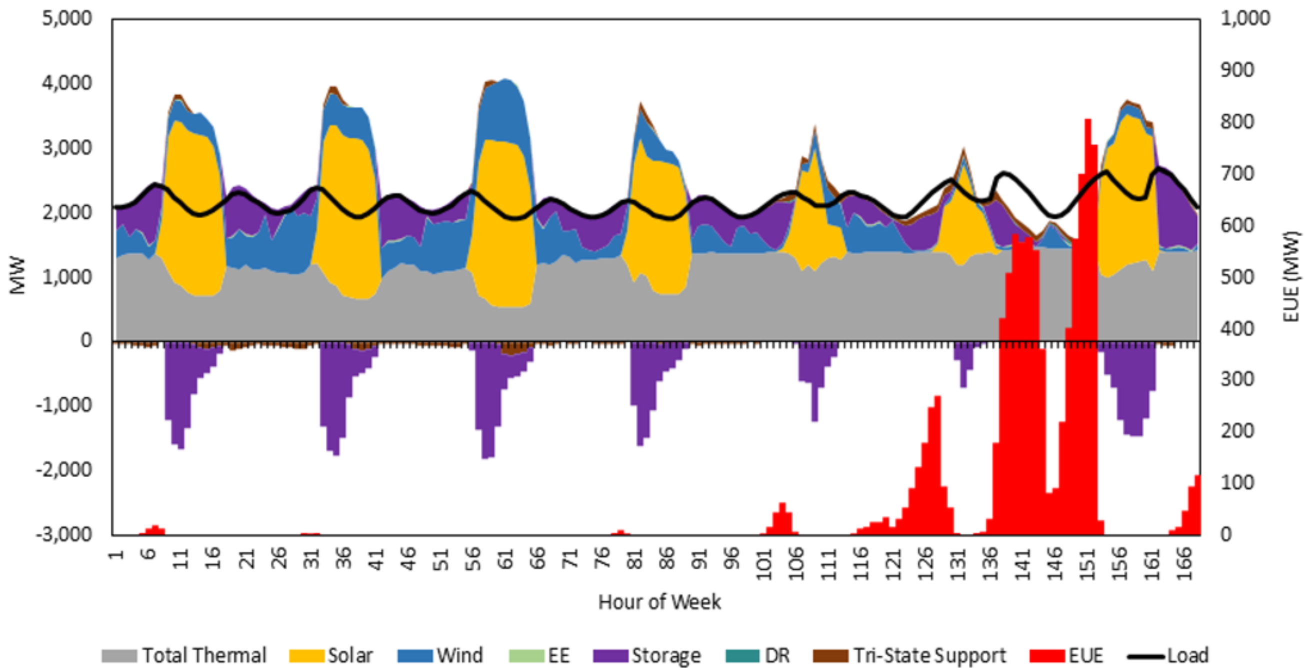
Generally, in summer, unserved energy in these islanded cases occurs in the early morning hours rather than at the evening net-load peak that drives summer risk in the base case. Storage discharges through the evening peak, is drawn down overnight, and reaches its lowest point shortly before sunrise, leaving a shallow shortfall in the pre-dawn hours that ends as solar generation returns for the day. The 2036, islanded, summer, CTP weekly dispatch is shown in **Figure 15** below and illustrates the frequent, lower EUE events that characterize summer LOLE.

Figure 15: CTP 2036 Summer Islanded Weekly Dispatch



In winter, loads are dual-peaking and during the intervals between successive peaks there is not enough energy to charge the storage resources. State of charge declines progressively across the week rather than recovering each night. This results in generally larger but less frequent EUE events concentrated at the end of the week, once storage is fully depleted. Winter therefore produces fewer hours of unserved energy than summer but far more unserved energy in total. This aligns with the heat maps and takeaways discussed in earlier sections, which likewise show greater EUE in winter than in summer. The 2036, islanded, winter, CTP weekly dispatch is shown in **Figure 16** and illustrates the higher magnitude EUE events that characterize winter LOLE.

Figure 16: CTP 2036 Winter Islanded Weekly Dispatch



For further interpreting the weekly EUE results, a useful metric is firm capacity as a percentage of peak load forecast. This is calculated as the combined nameplate capacity of combined cycle, combustion turbine, steam turbine, linear generator, nuclear, and geothermal resources, divided by the peak load forecast for the given portfolio and study year. Firm, dispatchable capacity is available albeit absent forced or planned outages irrespective of weather, time of day, or stored energy, and it is therefore what remains to serve load once storage has been depleted and solar and wind have receded. ***Table 47*** shows the calculated firm capacity ratios. Because the 0.1 LOLE calibration adjusts 4HR storage only, these ratios apply equally to the calibrated portfolios simulated in the resiliency analysis.

Table 47: Firm Capacity Ratio for Expansion Portfolios

Portfolio	Year	Firm / load	Summer Islanded Weekly EUE (MWh)	Winter Islanded Weekly EUE (MWh)
CTP	2036	42.5%	3,758	9,259
CTP	2040	39.8%	4,383	10,237
CTP	2045	47.4%	2,509	3,823
HEG	2036	37.6%	3,892	17,187
HEG	2040	37.8%	3,596	6,061
HEG	2045	45.3%	1,152	2,470

Both portfolios improve considerably by 2045, when combined cycle, steam turbine, and geothermal capacity retire and are replaced by 1,022 MW of small modular nuclear capacity. That addition is large enough to raise firm capacity to its highest share of the three study years in both portfolios, despite 2045 also carrying the highest load.

For the CTP portfolio as seen in Table 46, weekly EUE moves inversely with the firm capacity share in all three islanded cases. The 2040 case has the lowest firm capacity share of the three study years, because firm capacity falls in absolute terms between 2036 and 2040 as combustion turbine capacity retires faster than linear generation is added, while the load forecast continues to rise. It also produces the highest unserved energy in the winter week and summer islanded case. The 2045 case is the reverse, with the highest firm capacity share and the lowest unserved energy in summer and winter.

The HEG portfolio follows the same pattern where the lowest firm capacity share shows the higher EUE. The study year 2036 has the lowest firm capacity share and we see the EUE increase rapidly. At this point, we see the additional firm capacity in 2040 versus 2036 makes a substantial difference during the winter resiliency week because the storage fleet is able to be more fully charged entering into the week. The HEG 2036 case is a marked outlier. HEG 2036 and HEG 2040 provide almost exactly the same share of peak load from firm capacity, yet 2036 produces roughly three times the islanded winter unserved energy of 2040. The two cases do not, however, enter the week with identical storage: the 0.1 LOLE calibration removed 230 MW of 4HR storage from HEG 2036 and added 20 MW to HEG 2040, leaving 2036 with roughly 250 MW less short-duration storage. The 2036 and 2040 winter, islanded, HEG dispatches are shown in **Figure 17** and **Figure 18**.

Figure 17: HEG 2036 Winter Islanded Weekly Dispatch

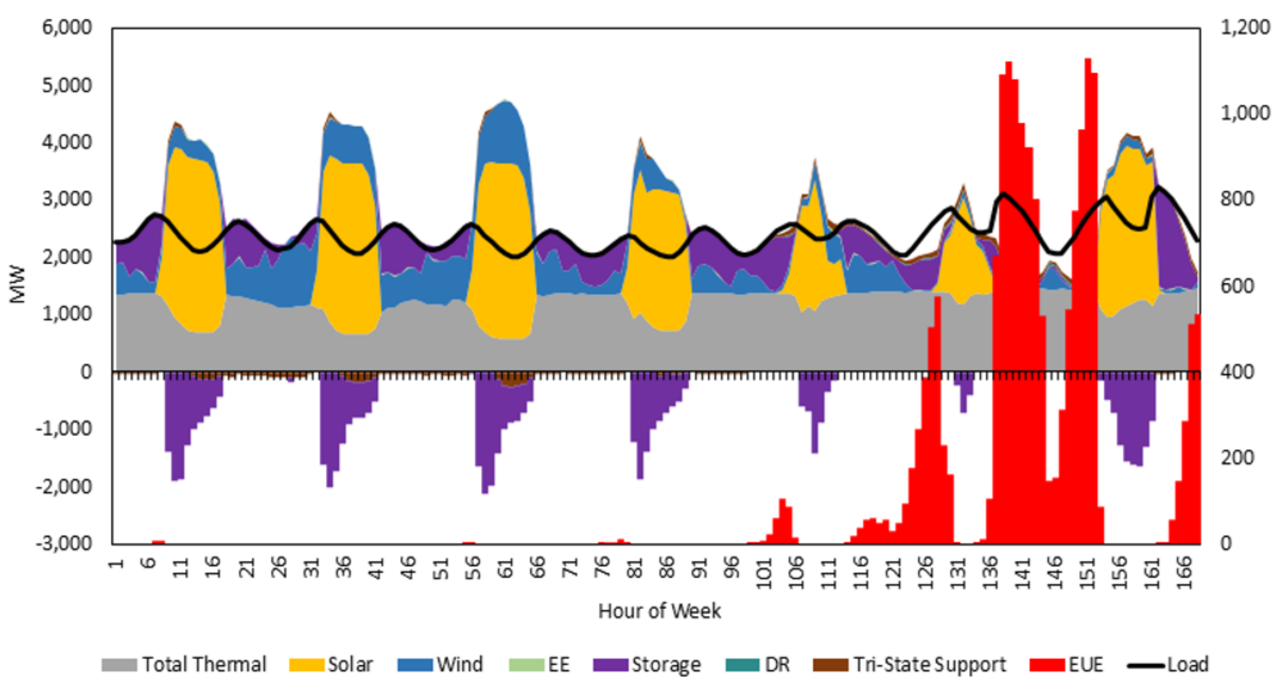
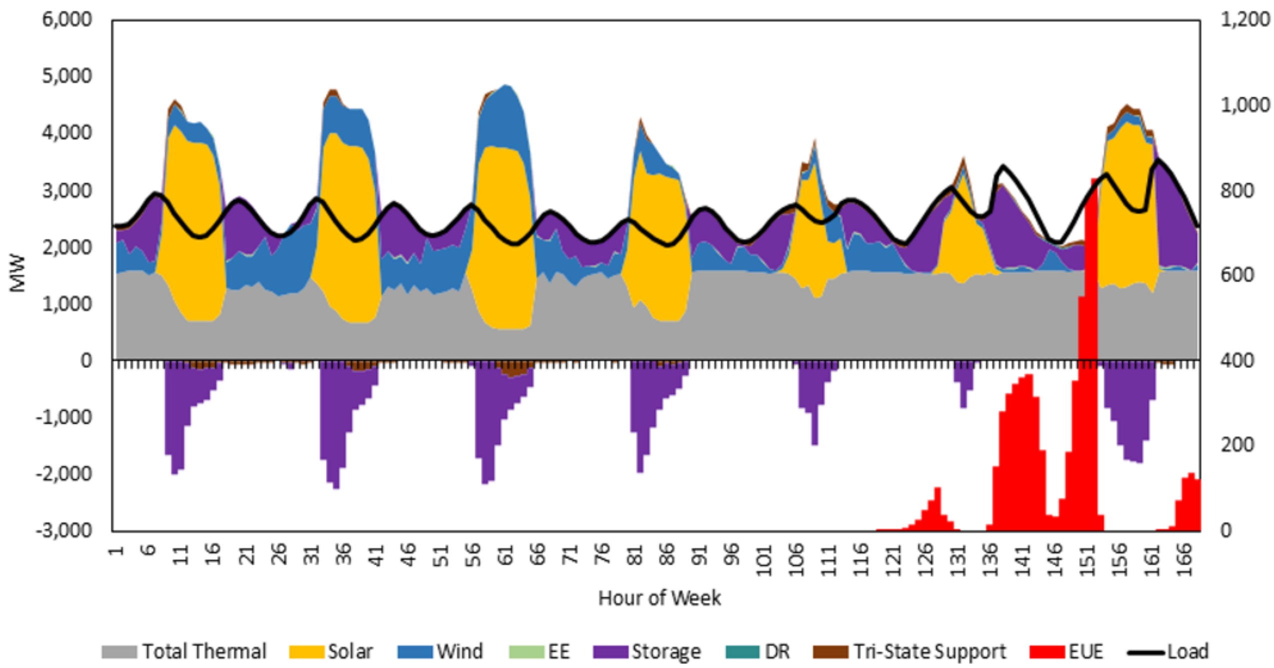


Figure 18: HEG 2040 Winter Islanded Weekly Dispatch



The explanation for the high 2036 unserved energy lies largely in how additional firm capacity performs across a sustained multi-day extreme weather period. The HEG 2040 portfolio carries over 100 MW more firm capacity than the HEG 2036 portfolio, and across the resiliency week that capacity delivers appreciably more energy despite serving higher load. It also begins the week with more short-duration storage. The difference is apparent from the beginning of the week. In the 2036 case small shortfalls appear on the first day and recur on most days that follow, indicating an energy shortfall from the outset. HEG 2040 records no unserved energy at all through the first four days of the extreme winter week.

Resiliency Comparison of Different Technologies

The second part of the resiliency analysis compares how different resource technologies perform under extreme conditions when each is sized to provide the same reliability. Starting from the CTP 2036 portfolio calibrated to 0.1 LOLE, 100 MW of load was added, and each of four technologies (an LM6000 combustion turbine, 4HR storage, DR, and solar paired with storage at a 2:1 solar-to-storage ratio) was then added independently in the amount required to return the system to 0.1 LOLE. Because every scenario is calibrated to the same annual LOLE, the EUE differences highlight how each technology helps the portfolio when the system experiences extreme weather. Each scenario was evaluated first on EUE across a full simulation of all weather years, and then on EUE and system dispatch during the same extreme summer and winter weeks used in the portfolio resiliency analysis. The results of this analysis are shown in ***Table 48***.

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Table 48: Resiliency Comparison of Different Technologies

Marginal Resource	Marginal MW	Full Study Annual EUE (MWh)	Summer Extreme Week EUE (MWh)	Winter Extreme Week EUE (MWh)
LM6000	105	67	26	145
4HR	345	107	13	603
Demand Response	580	73	0	474
Solar and Storage	580/290	100	<1	463

Across the full simulation of all weather years, the LM6000 produces the lowest annual EUE at 67 MWh, followed by DR at 73 MWh, solar and storage at 100 MWh, and 4HR storage at 107 MWh. The ordering reflects how much each resource is limited by energy rather than capacity. The LM6000 can serve a deficit of any duration once committed unless it is on forced outage or planned maintenance, so the capacity added closely matches the capacity the system was short. DR is constrained by the number and length of events it can be called for, but those events are long enough to cover most hours in which the system is short. The solar and storage case and the 4HR resource depend on stored energy and on the opportunity to recharge, so a portion of their capacity is unavailable in the longest events and considerably more of it is required to reach the same annual reliability.

The extreme summer week reverses part of that ordering. With 100 MW of additional load, the 4HR and the solar and storage scenarios record 13 MWh and less than 1 MWh of unserved energy, and DR records none, against 26 MWh for the LM6000. Summer shortfalls are concentrated in a few late afternoon and evening hours, which is within the discharge duration of storage. Because the energy limited resources require far more installed capacity to reach the same annual reliability, 345 MW of 4HR, 580 MW of solar with 290 MW of storage, and 580 MW of DR against 105 MW of the LM6000, that additional capacity is available in the hours when the system is short and the events are brief enough that stored energy is not exhausted. DR clears the extreme summer week with no unserved energy for the same reason: the large amount of DR added (580 MW) overcomes the summer events. The extreme winter week results are aligned with the annual results. Winter risk is driven by cold that persists across several days and a morning and evening peak rather than by a single evening peak, leaving the energy limited resources (even with much higher capacity levels) unable to sustain output through the event or to fully recharge between days. The LM6000 holds winter extreme week EUE to 145 MWh, while DR reaches 474 MWh, solar and storage 463 MWh, and 4HR storage 603 MWh despite their much larger installed capacity. DR clears the summer week but is constrained in winter by the number and duration of events it can be called, so it cannot cover a multi-day cold event and performs in line with the energy limited resources rather than with the LM6000. Sustained winter conditions therefore favor firm capacity.

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Appendix

Table 49: PNM Solar Profile Locations

Profile Name	Latitude	Longitude
Alamogordo	32.8863	−105.9708
Alamosa	35.0780	−106.7083
Albuquerque	35.0840	−106.6500
Alta Luna	32.5708	−107.4885
Arroyo Solar	35.9715	−107.5602
Bluewater	35.2578	−107.9396
Britton	35.0129	−106.0954
Cimarron	36.4681	−104.6396
Cuba	36.0174	−106.9460
Encino	35.3266	−106.8562
Escalante	35.4161	−108.0873
Estancia	34.7826	−106.0558
Jicarilla Solar I	36.3284	−107.2779
NMRD	35.0747	−106.8644
Quail Ranch Solar	35.2164	−106.8358
Route 66	35.1029	−107.6158
San Juan Solar	36.8021	−108.4425
Sky Ranch	34.7826	−106.7798
Spanish Peaks	37.3770	−104.4590
Springer	36.3981	−104.5942
Storrie	35.6569	−105.1839
TAG Solar PV	35.3297	−106.8549
Alamogordo	32.8863	−105.9708

Table 50: Neighbor Solar Profile Locations

Profile Name	Latitude	Longitude
Arizona 1	35.85	−111.90
Arizona 2	36.29	−109.70
Arizona 3	34.65	−109.42
Arizona 4	35.29	−114.22
Arizona 5	32.93	−109.70
Arizona 6	31.45	−109.70
EPE 1	31.61	−105.02
EPE 2	32.13	−105.70
PSCo 1	40.53	−105.74
PSCo 2	38.29	−103.30

Figure 19: CTP 2036 Summer Interconnected Weekly Dispatch

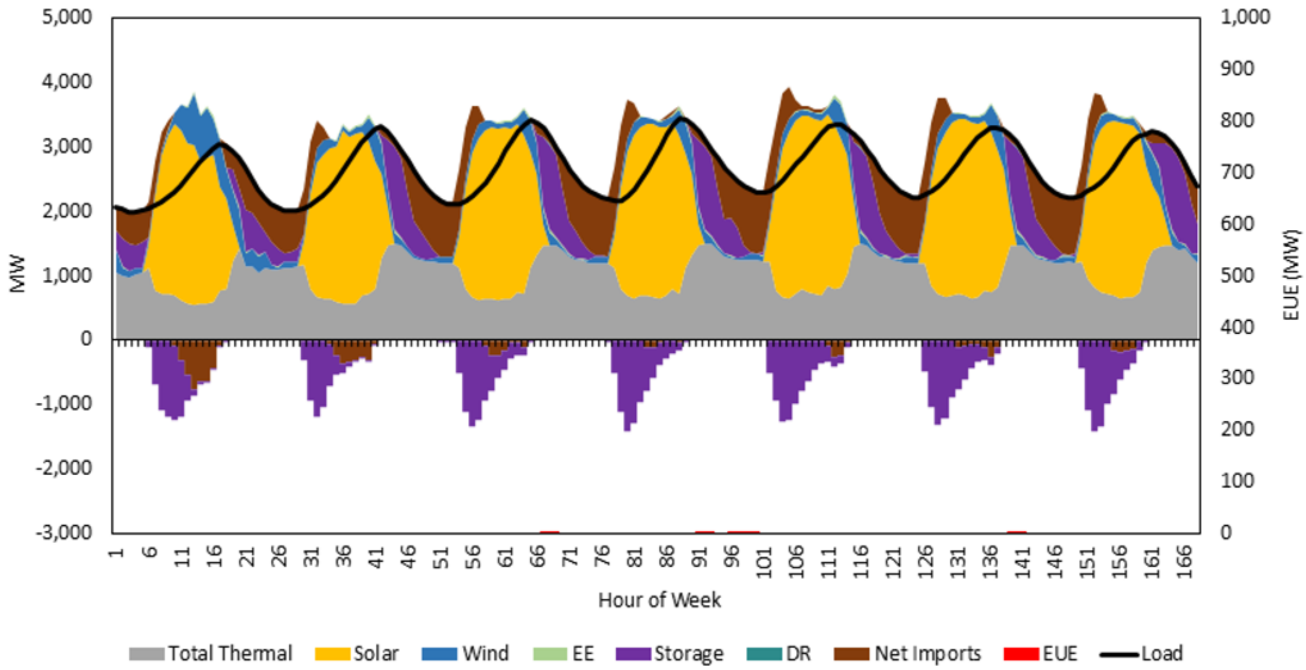

Figure 20: CTP 2036 Summer Islanded Weekly Dispatch

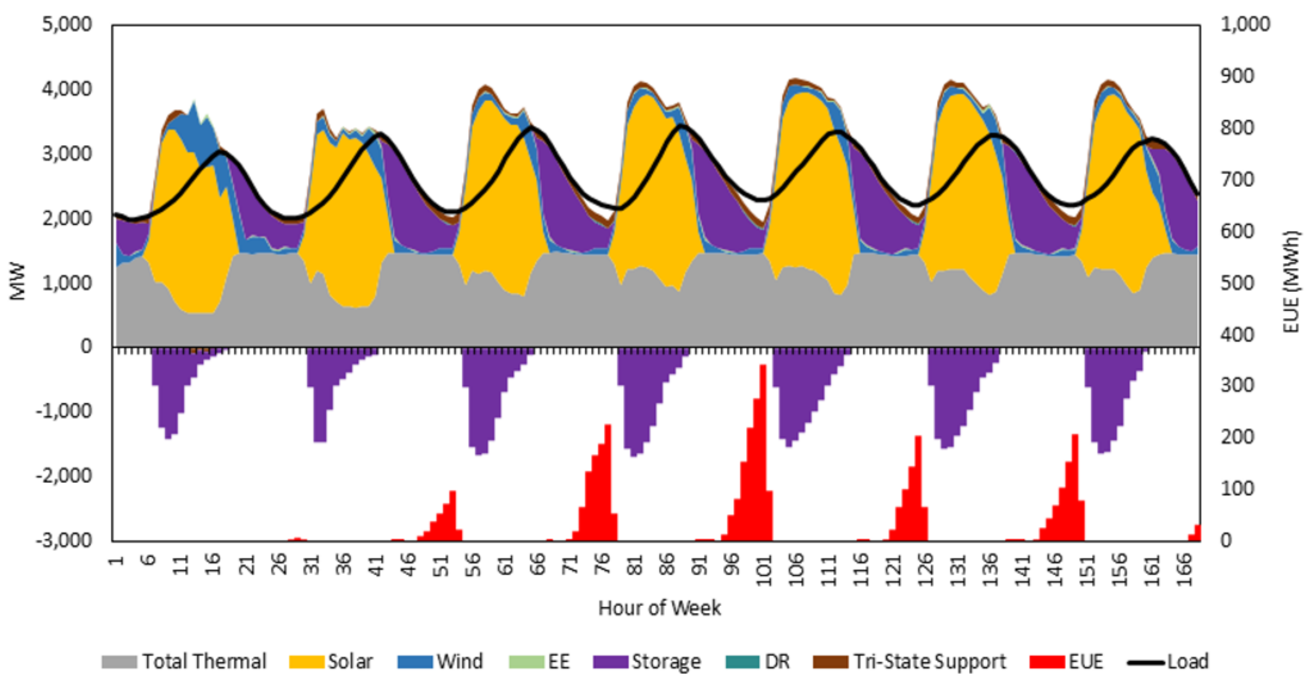

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Figure 21: CTP 2040 Summer Interconnected Weekly Dispatch

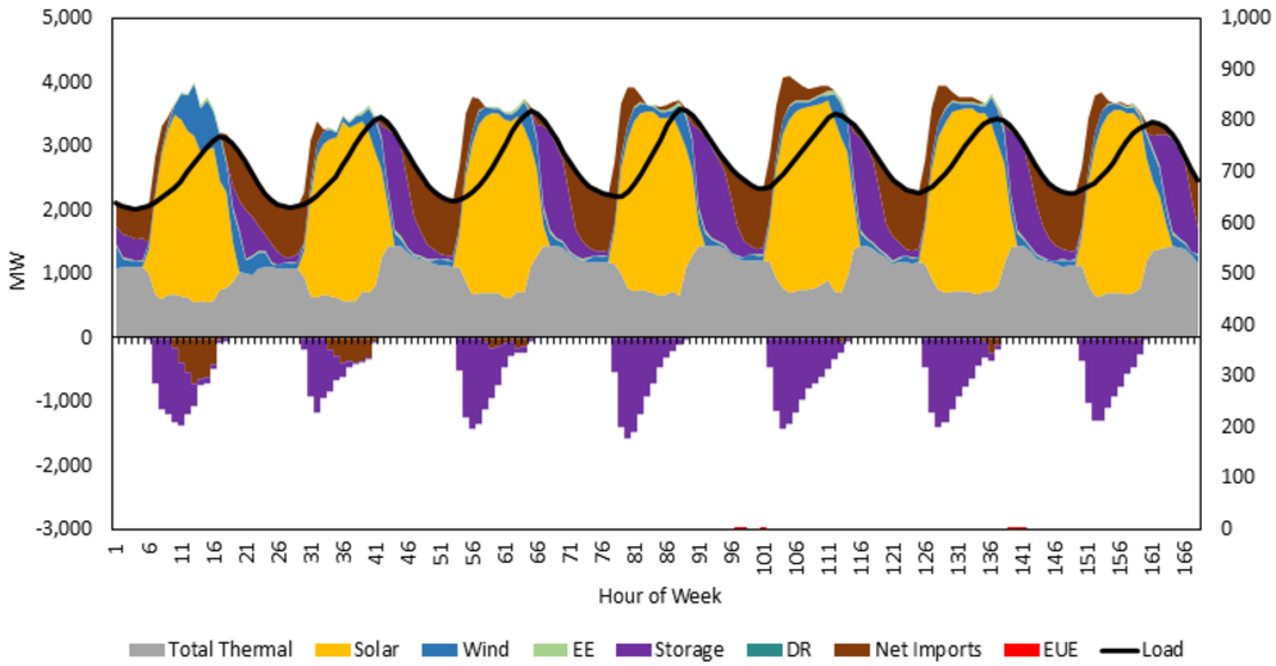

Figure 22: CTP 2040 Summer Islanded Weekly Dispatch

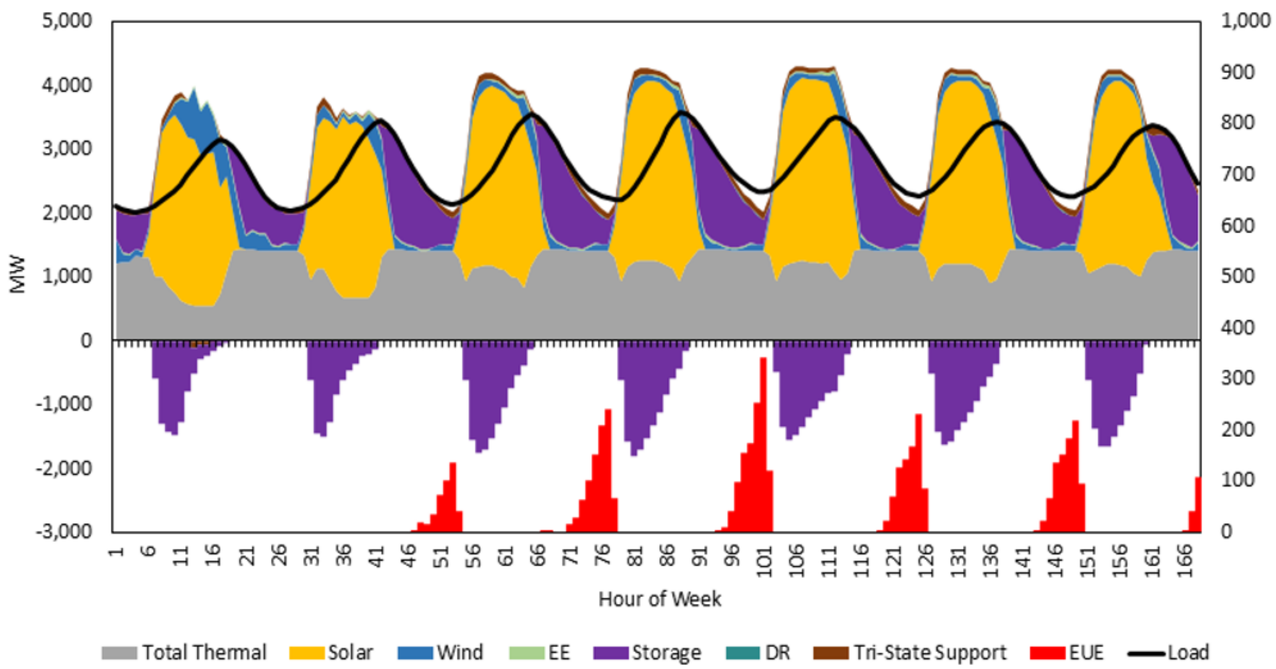

Figure 23: CTP 2045 Summer Interconnected Weekly Dispatch

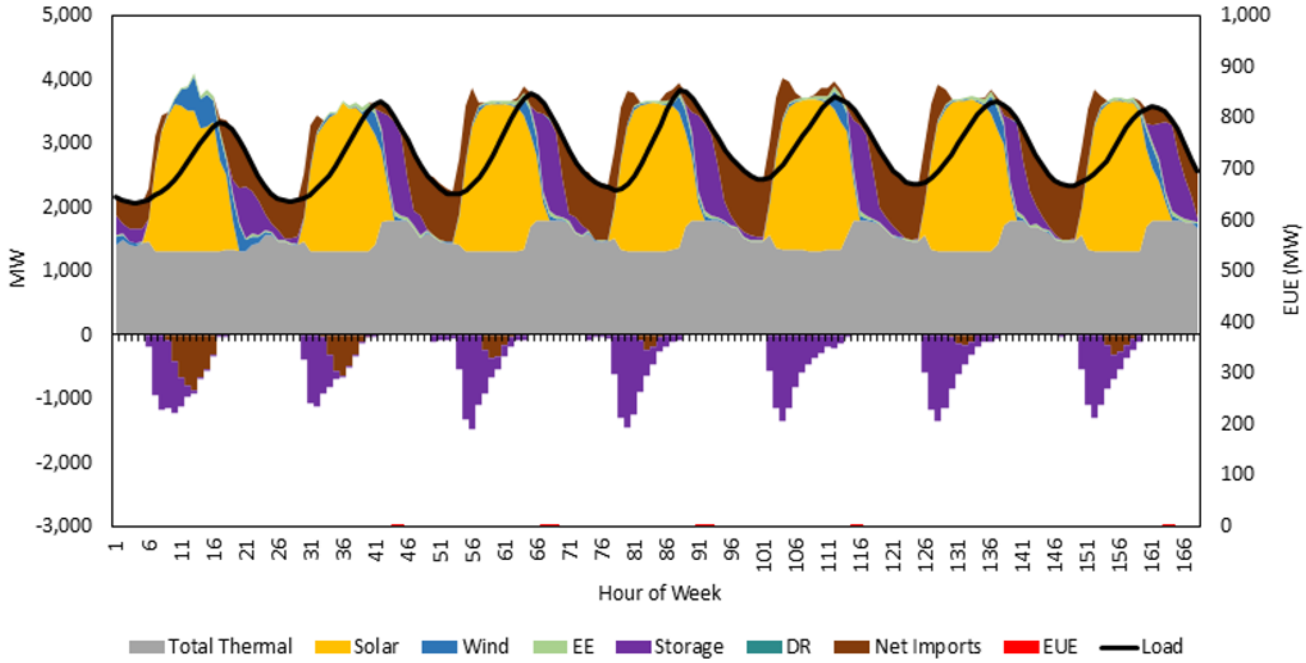

Figure 24: CTP 2045 Summer Islanded Weekly Dispatch

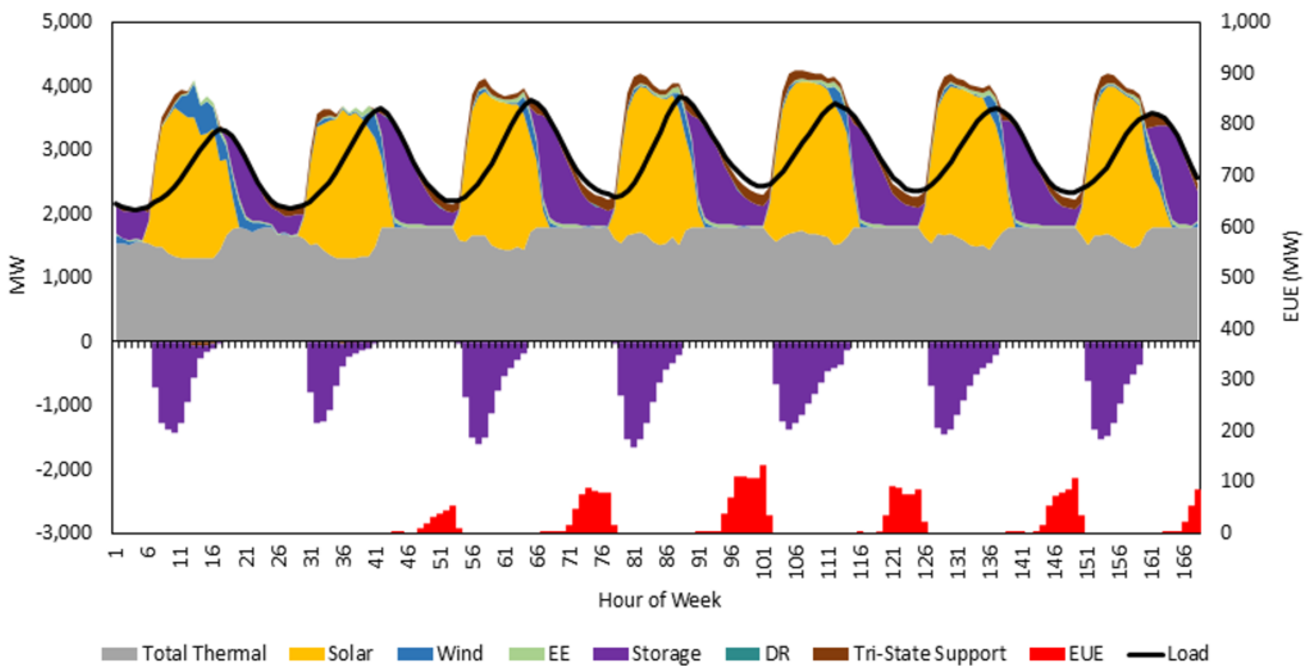

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Figure 25: CTP 2036 Winter Interconnected Weekly Dispatch

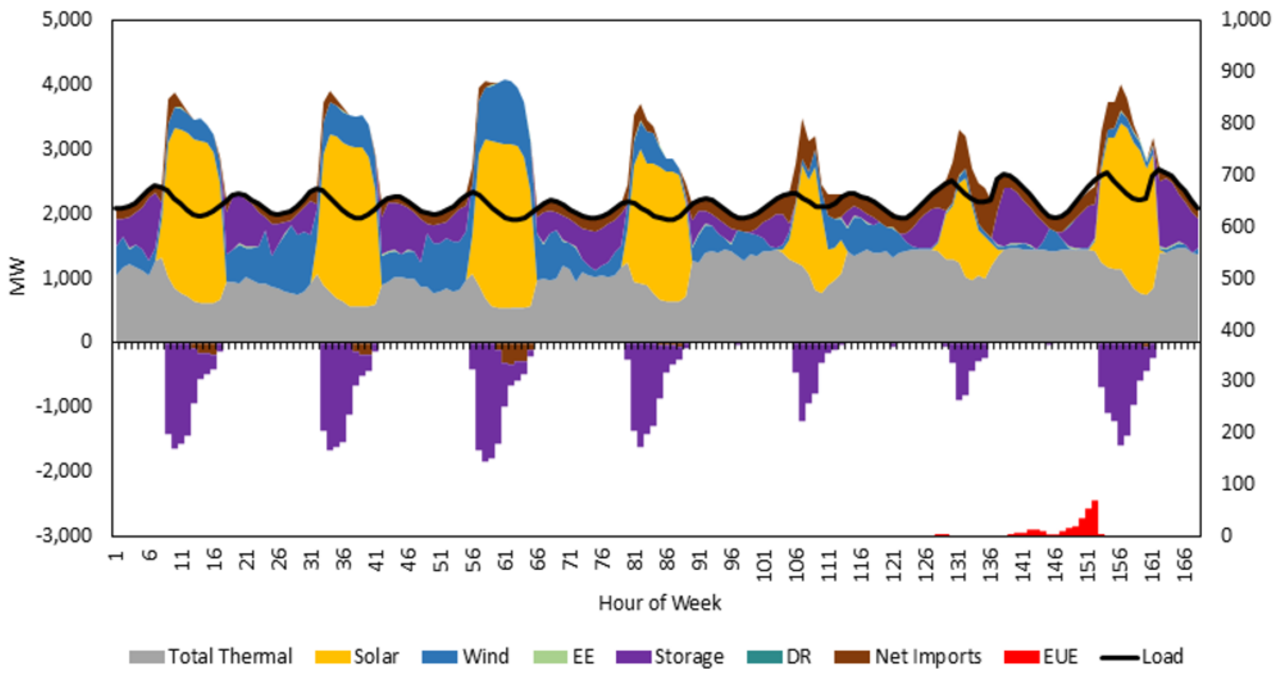

Figure 26: CTP 2036 Winter Islanded Weekly Dispatch

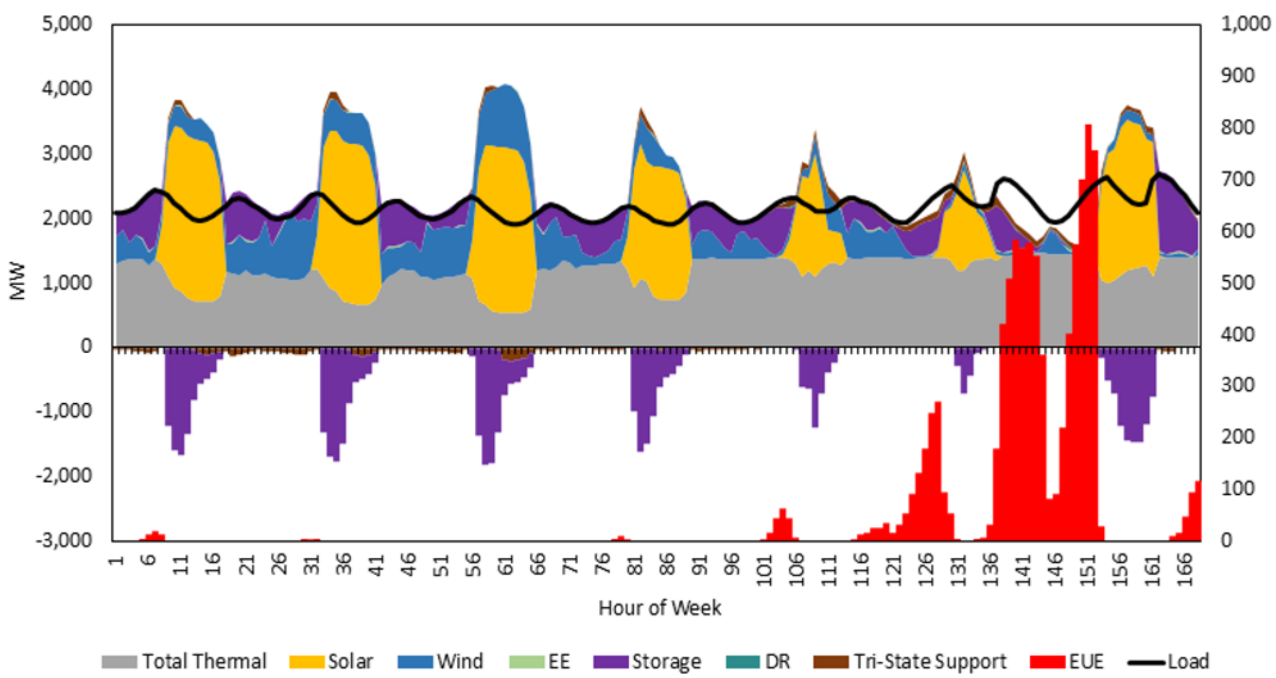

Figure 27: CTP 2040 Winter Interconnected Weekly Dispatch

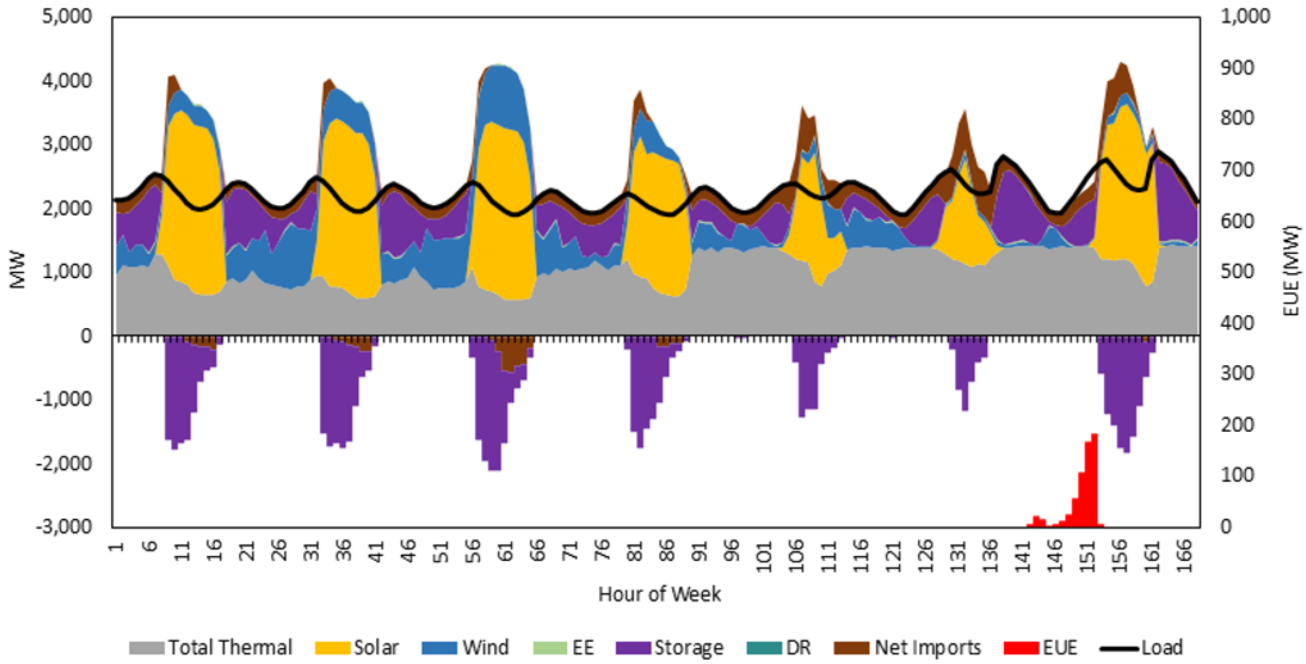

Figure 28: CTP 2040 Winter Islanded Weekly Dispatch

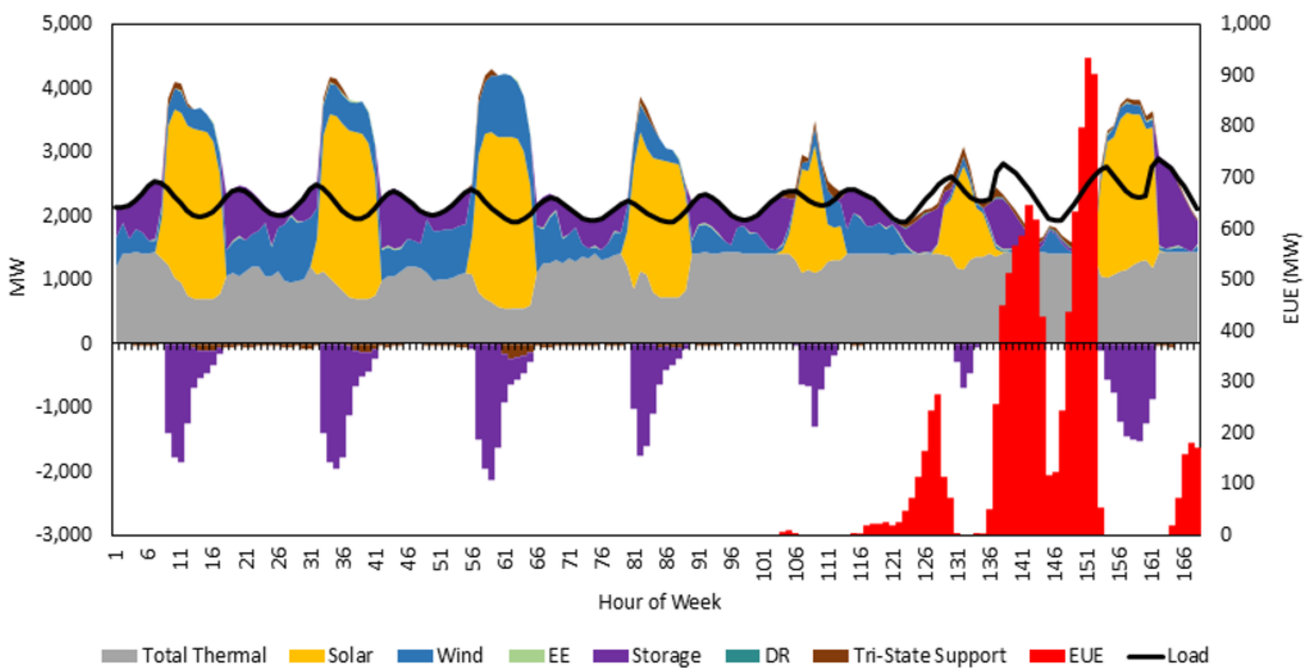

Figure 29: CTP 2045 Winter Interconnected Weekly Dispatch

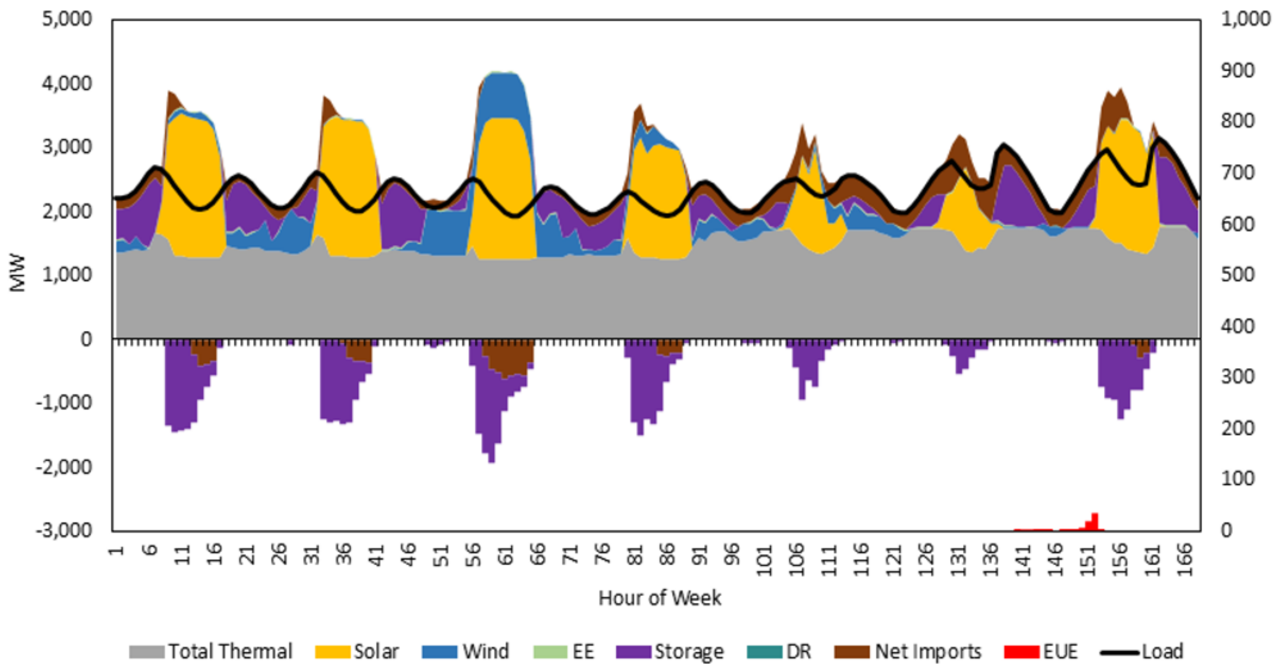

Figure 30: CTP 2045 Winter Islanded Weekly Dispatch

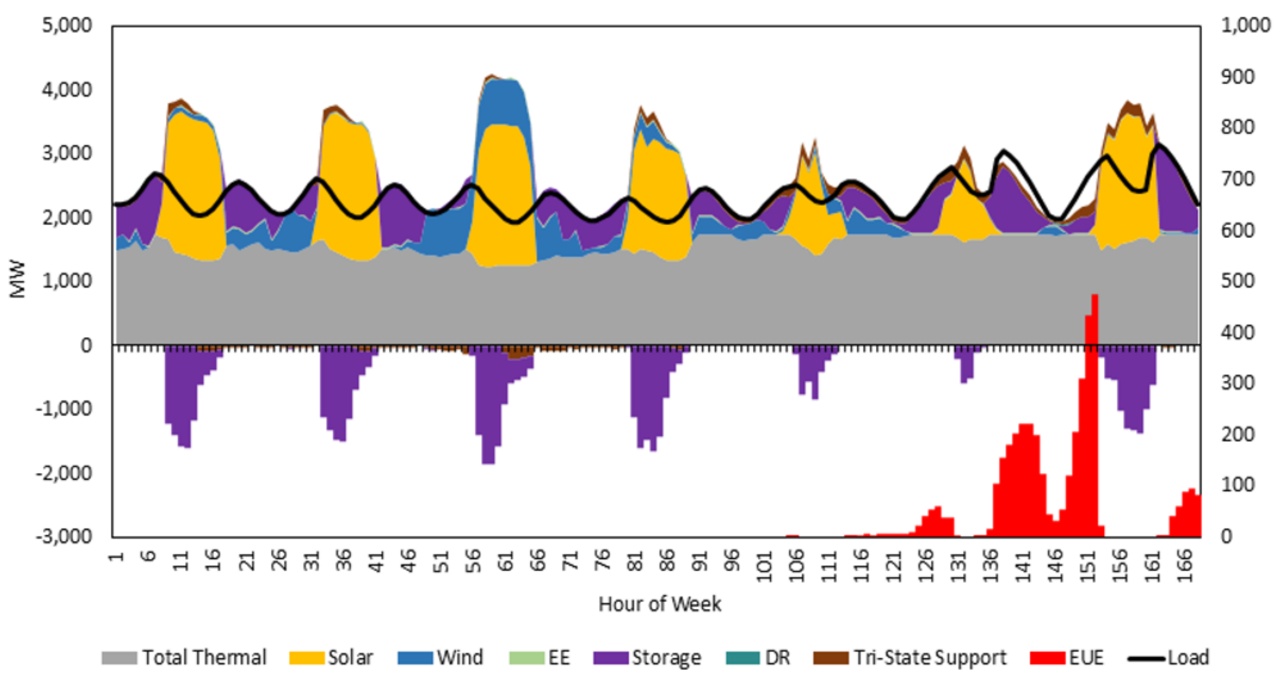

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Figure 31: HEG 2036 Summer Interconnected Weekly Dispatch

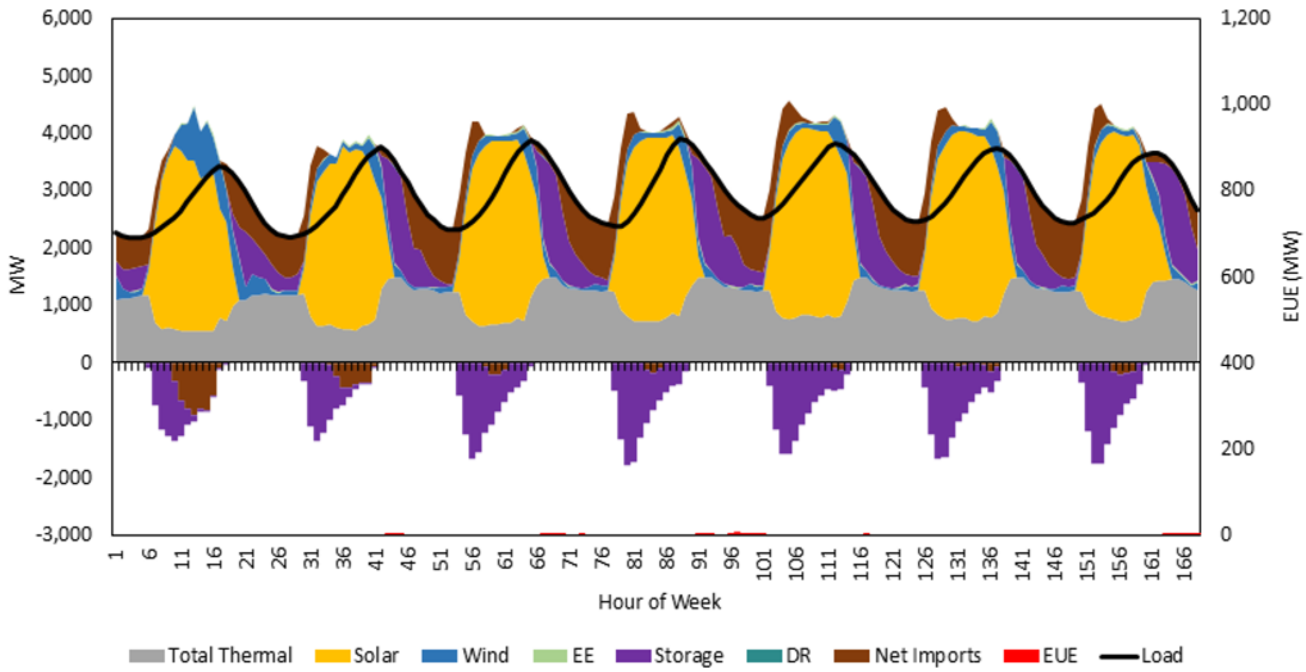

Figure 32: HEG 2036 Summer Islanded Weekly Dispatch

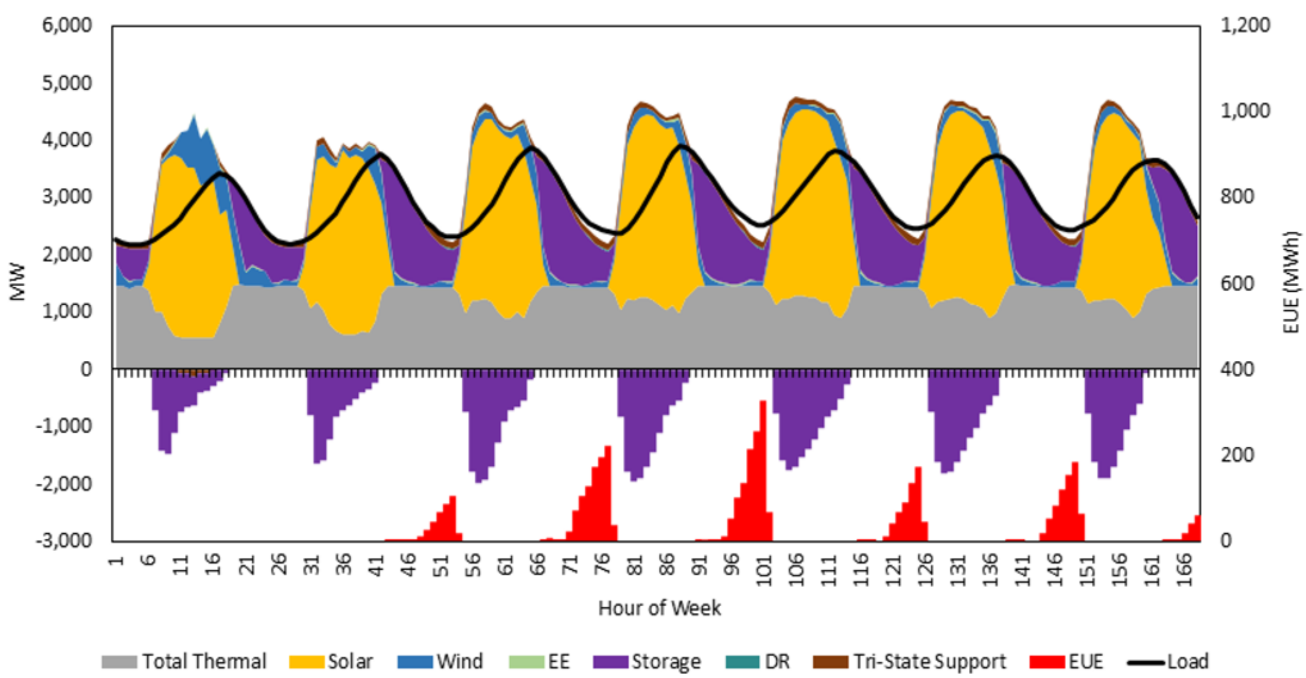

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Figure 33: HEG 2040 Summer Interconnected Weekly Dispatch

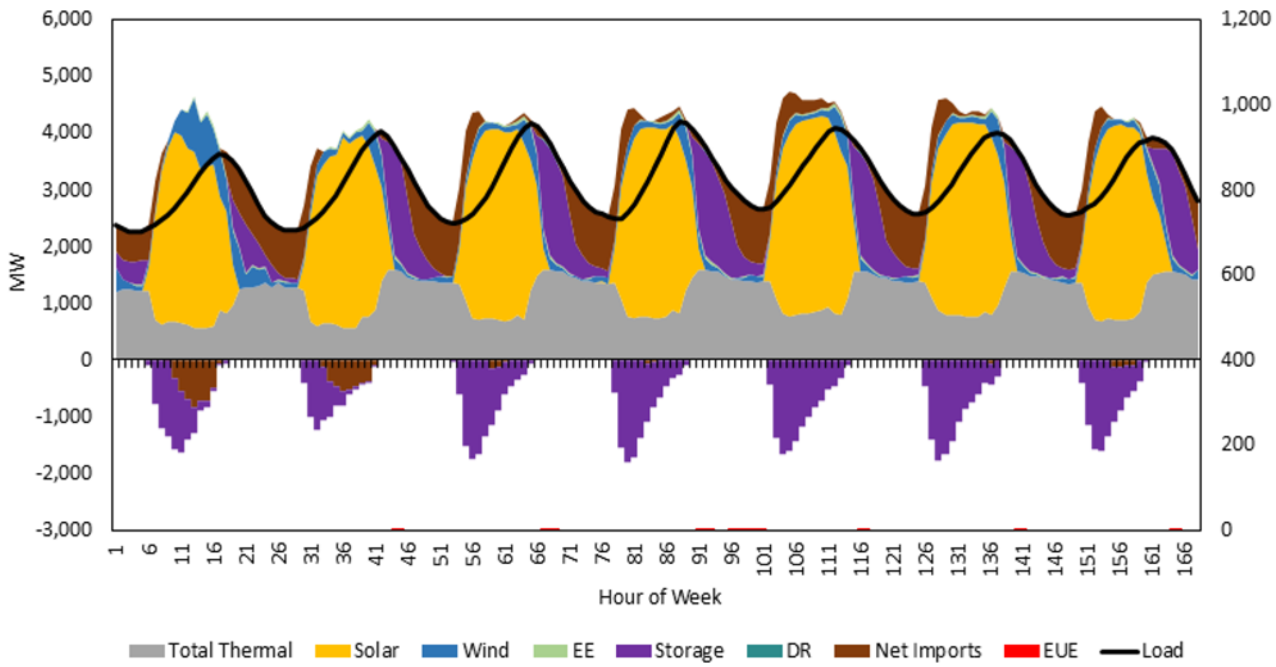

Figure 34: HEG 2040 Summer Islanded Weekly Dispatch

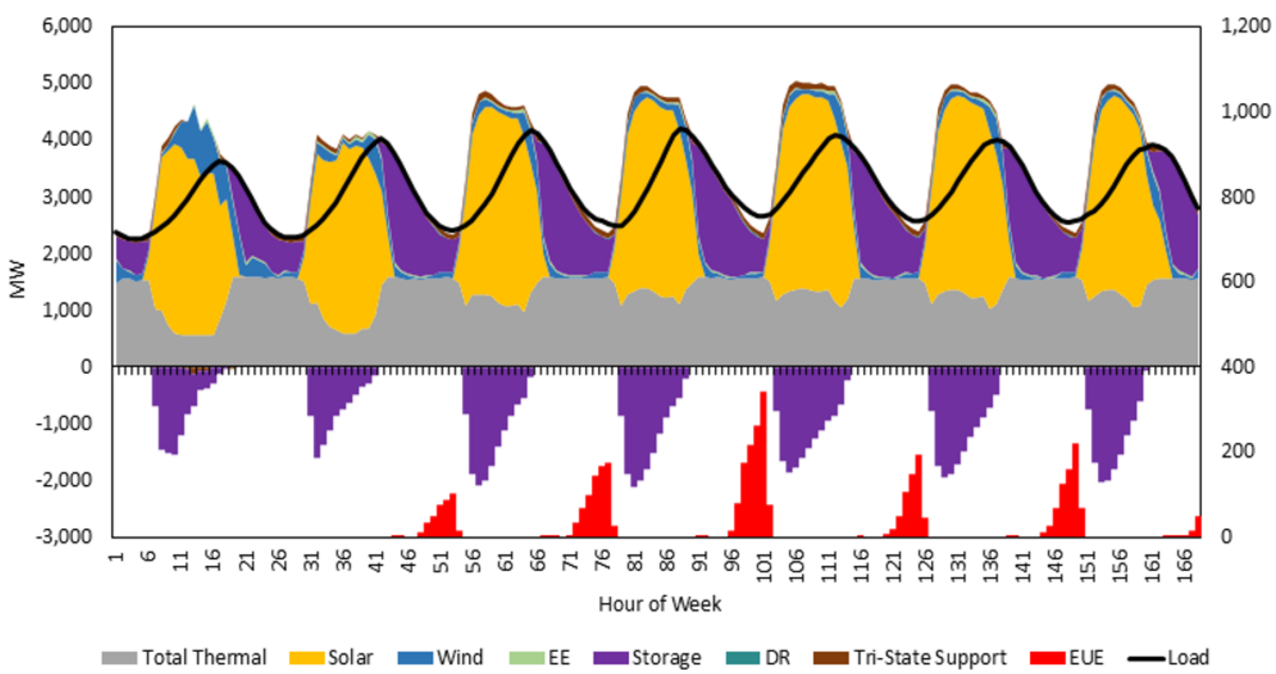

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Figure 35: HEG 2045 Summer Interconnected Weekly Dispatch

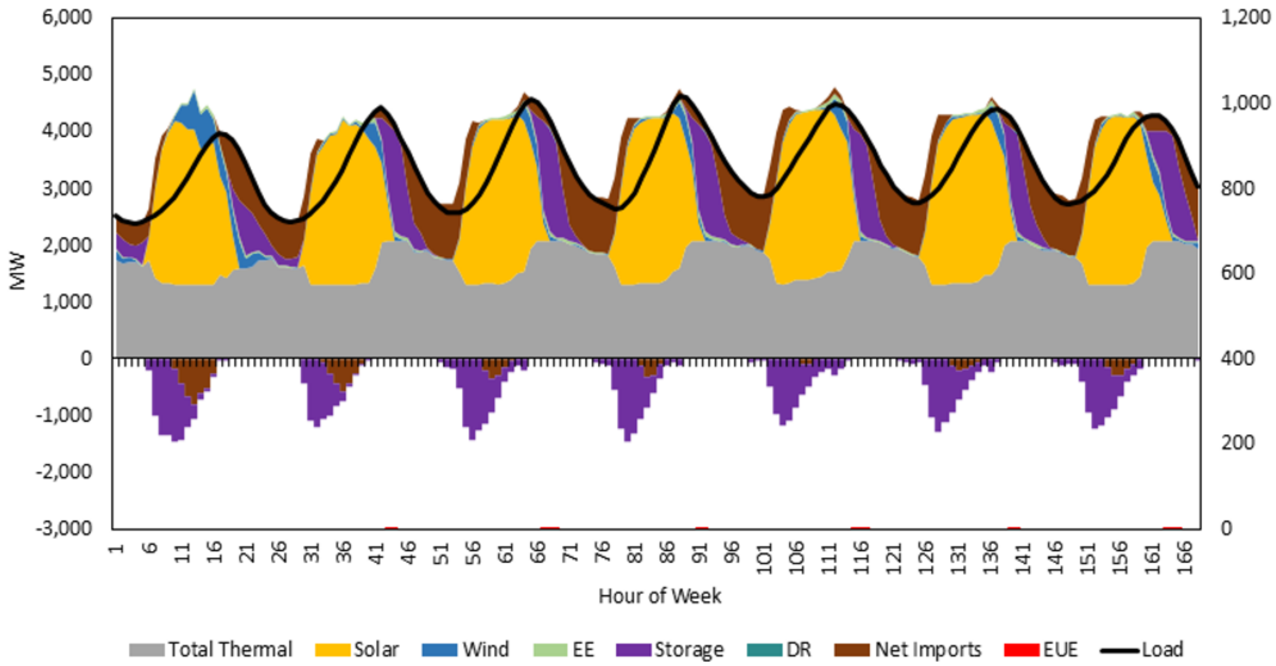

Figure 36: HEG 2045 Summer Islanded Weekly Dispatch

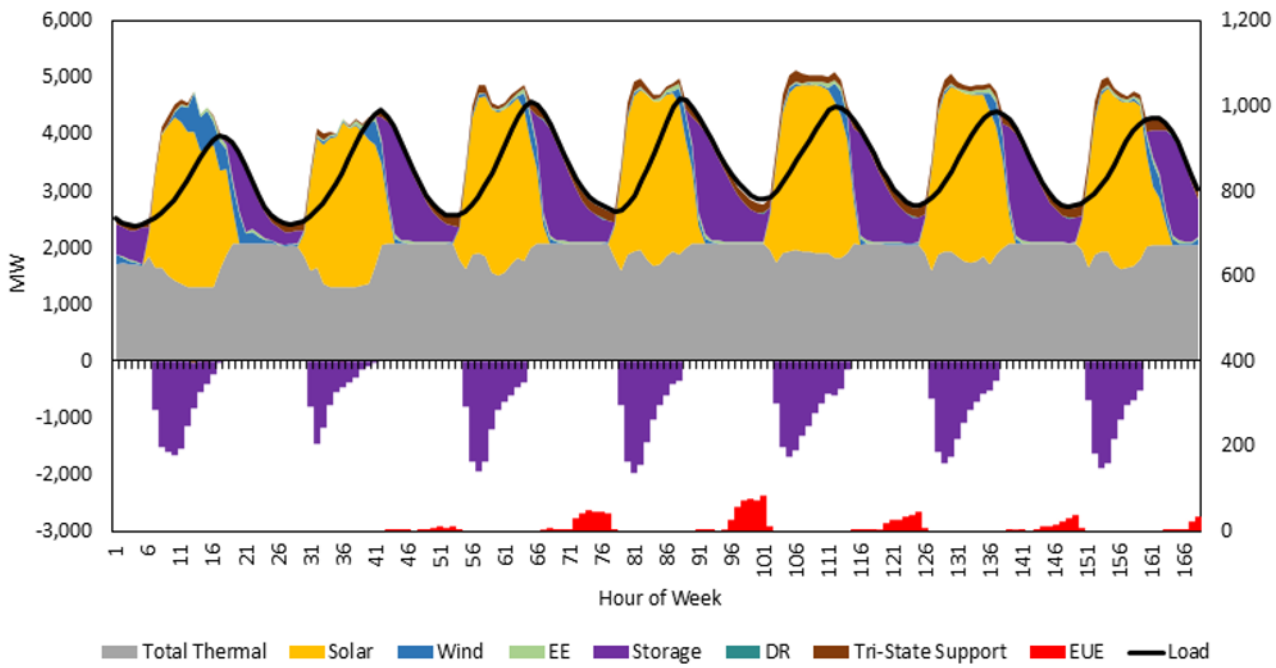

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Figure 37: HEG 2036 Winter Interconnected Weekly Dispatch

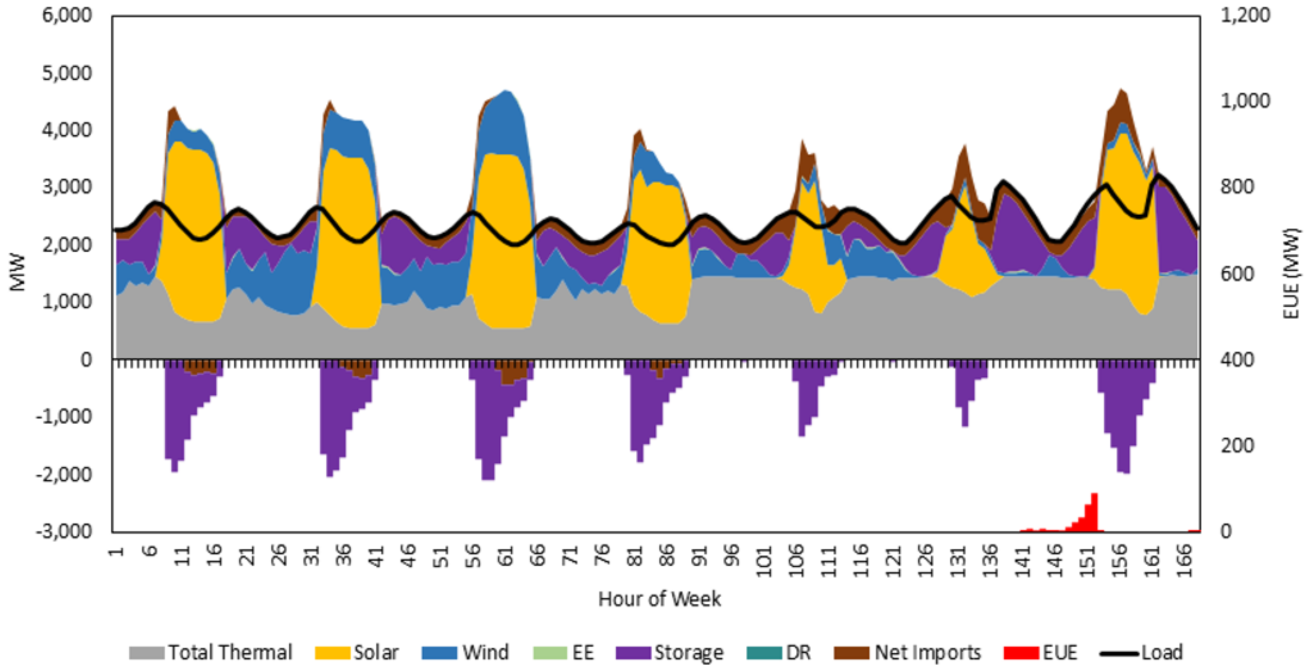

Figure 38: HEG 2036 Winter Islanded Weekly Dispatch

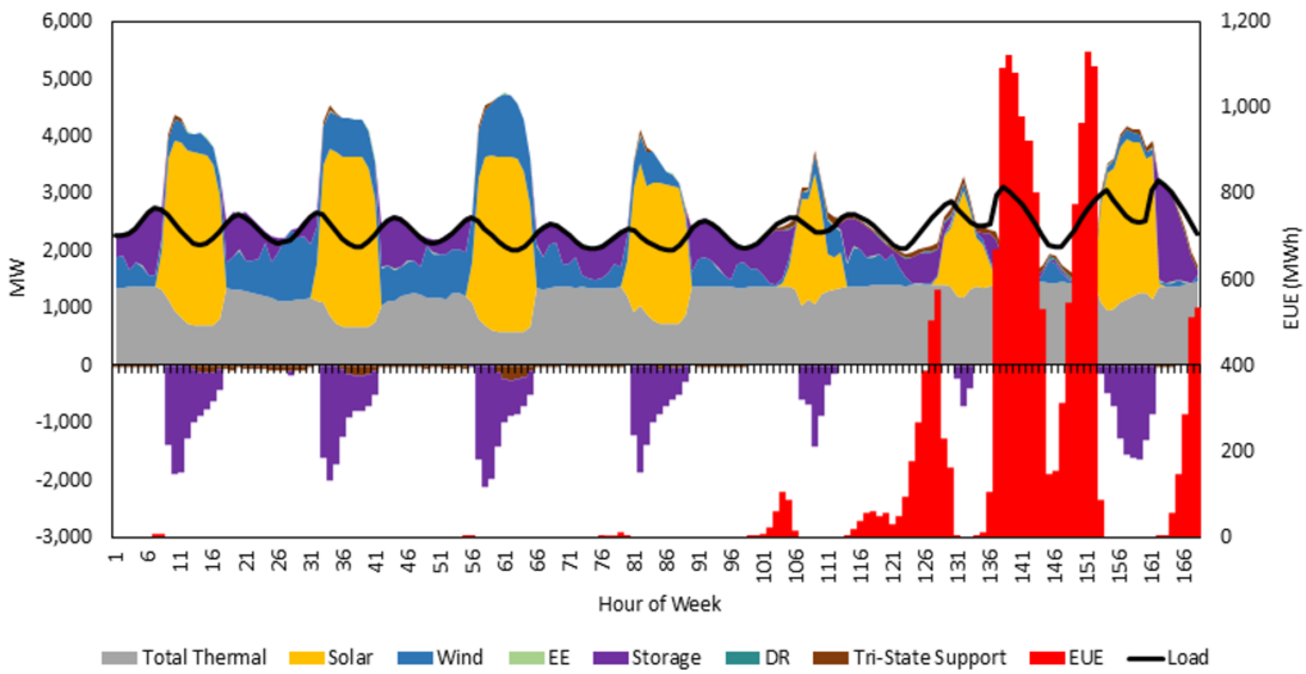

Figure 39: HEG 2040 Winter Interconnected Weekly Dispatch

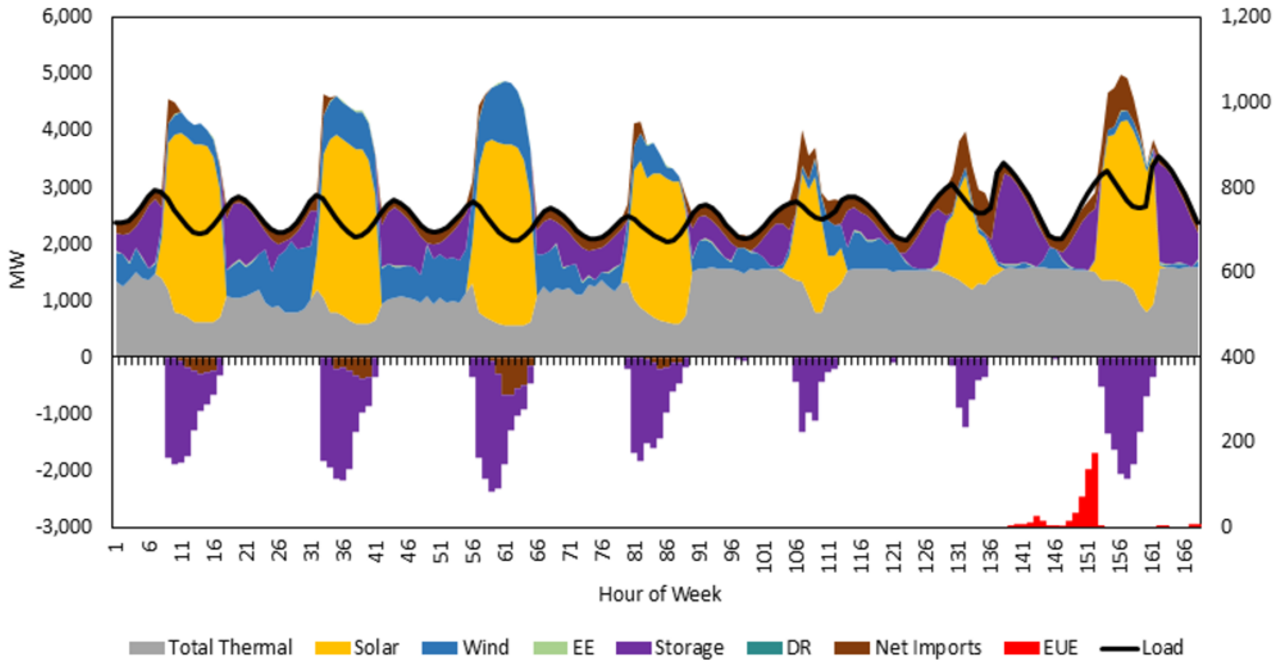

Figure 40: HEG 2040 Winter Islanded Weekly Dispatch

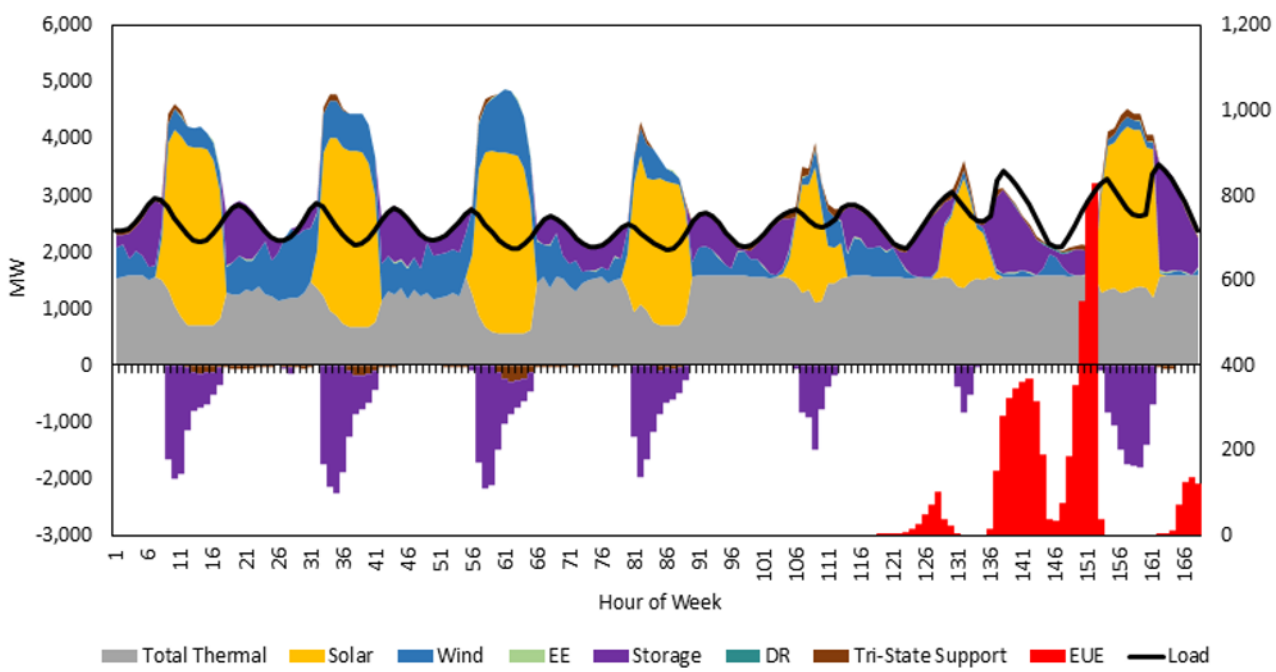

Figure 41: HEG 2045 Winter Interconnected Weekly Dispatch

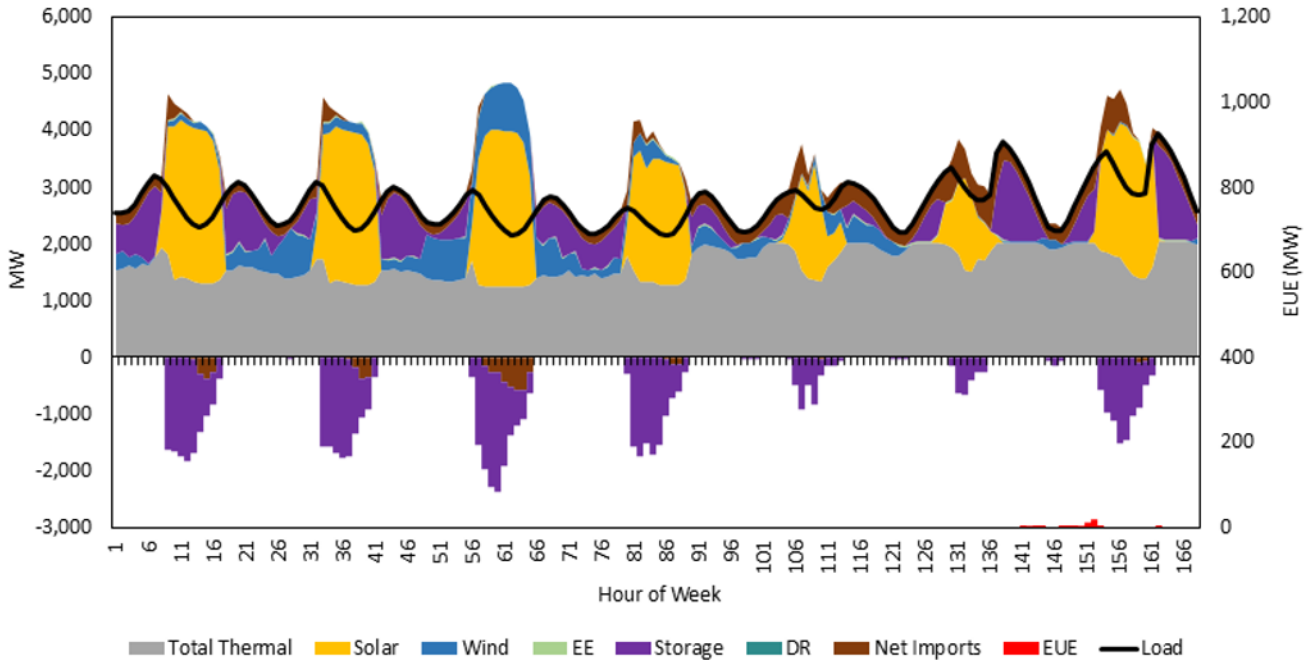

Figure 42: HEG 2045 Winter Islanded Weekly Dispatch