

APPENDIX A: ANALYSIS OF LARGE LOAD IMPACTS ON DELAWARE

I. INTRODUCTION

In order to better understand the impacts of large load additions, the DNREC State Energy Office engaged Siemens Energy and Synapse Energy Economics to perform modeling of locational marginal prices (LMPs) and reliability effects on Delaware. The modeling performed identifies significant cost and reliability impacts for Delaware.

II. IMPACTS OF LARGE LOAD CUSTOMERS ON DELAWARE

A. Electric Supply Cost Impacts

Siemens Energy conducted a security-constrained economic dispatch (SCED) study for the DNREC to evaluate the wholesale electric supply cost impacts associated with a few prospective load additions. The purpose of this analysis was to quantify the incremental impact of the proposed data centers on wholesale energy prices under PJM's LMP framework and to assess how those impacts vary by time and location within Delaware. Because standard offer service rates are tied to wholesale market outcomes, sustained changes in LMPs directly affect electricity supply costs borne by residential, commercial, and industrial customers statewide.

1. Methodology

The analysis applied a SCED modeling framework that simulates hourly operation of the electric power system by dispatching available generation resources to meet load while respecting transmission constraints and reliability requirements, consistent with PJM market operations. Siemens Energy implemented the analysis using the PROMOD market simulation platform, which includes detailed nodal representation of the PJM region and models transmission congestion and losses.

LMPs were evaluated at 10 representative substations distributed across the counties of New Castle, Kent, and Sussex to capture geographic variation in price impacts across the state.

Three scenarios were evaluated for calendar year 2029:

- **Base Case:** Expected system conditions without the incremental data center load.
- **Scenario 1:** Addition of a single 1.2 GW data center load at the Red Lion 500 kV substation in northern Delaware, with all other assumptions held constant.
- **Scenario 2:** Addition of the 1.2 GW data center load at the Red Lion 500 kV substation, plus addition of 1.2 GW of distributed data center load across six substations at 230 kV and higher voltages, assumed as approximately 200 MW at each of the following nodes:
 - Hay Road (230 kV)

- Keeney (500 kV)
- Silver Run (230 kV)
- Cartanza (230 kV)
- Milford (230 kV)
- Indian River (230 kV)

2. Statewide Wholesale Price Impacts

The study found that the addition of the data center load results in a clear and sustained increase in wholesale electricity prices across Delaware.

Table 3. Projected increase in average annual LMP				
	2025 Actual	Base Case (2029)	Scenario 1 (2029)	Scenario 2 (2029)
Annual Average LMP (\$/MWh)	49.77	54.32	59.23	98.90
Percent Change over Previous Column	N/A	9.14%	9.06%	66.95%
Percent Change over Base Case	N/A	N/A	9.06%	82.07%

In Scenario 1, the projected average 2029 LMP increases by approximately \$4.92/MWh, or 9.1 percent, when the single data center load is added. In Scenario 2, projected average 2029 LMP increases by \$44.58/MWh, or 82.1 percent over the Base Case. This increase reflects higher marginal generation costs, increased transmission congestion, and higher system losses required to serve the incremental load.

3. Temporal Patterns of Cost Impacts

Price impacts are not uniform throughout the year. The analysis shows that the largest increases in LMPs occur during periods of system stress, particularly during the coldest winter months and the hottest summer months.

LMP impacts are highest in January and February, reflecting winter peak conditions. Elevated impacts also occur in July and August, when summer cooling demand is highest. These patterns are even more prominent in Scenario 2.

**Average LMP Change (monthly)
Scenario 1 and Scenario 2 compared to Base Case**

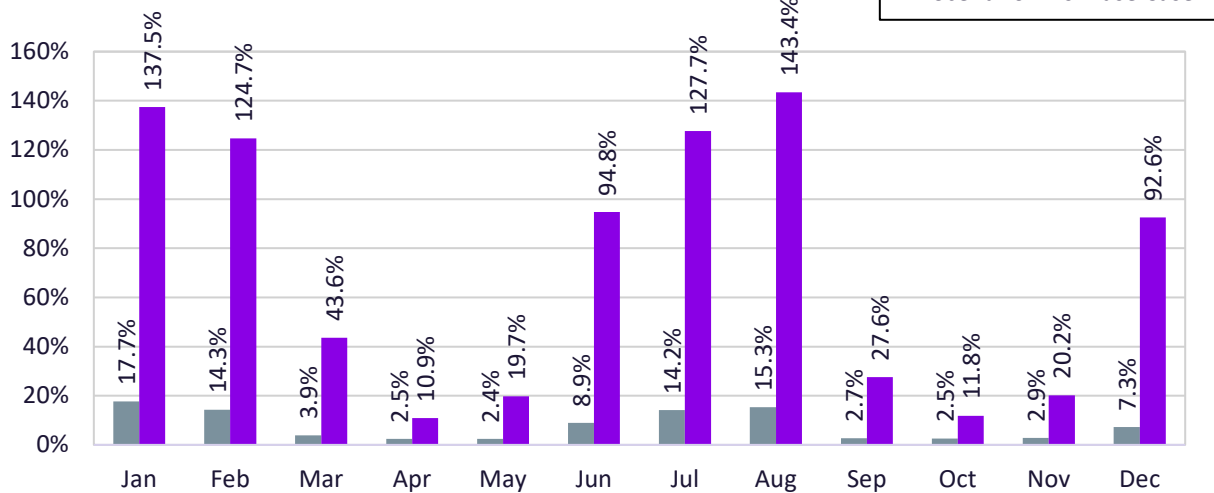


Figure 1. Monthly change in LMPs between Base Case, Scenario 1, and Scenario 2

The impact will also be significantly higher during PJM peak hours (07.00 through 23.00) as compared to off-peak hours.

Table 4. Peak and off-peak change in LMP				
Period		Base Case	Scenario 1	Scenario 2
Peak	LMP (\$/MWh)	57.92	64.16	112.45
	Change over Base Case		10.8%	94.2%
Off-Peak	LMP (\$/MWh)	50.73	54.33	85.39
	Change over Base Case		7.1%	68.3%

The hourly profile underscores how Scenarios 1 and 2 exacerbate the system’s existing seasonal and diurnal cost patterns: higher costs during the coldest winter mornings, the hottest summer afternoons, and periods when transmission flows approach their operational limits.

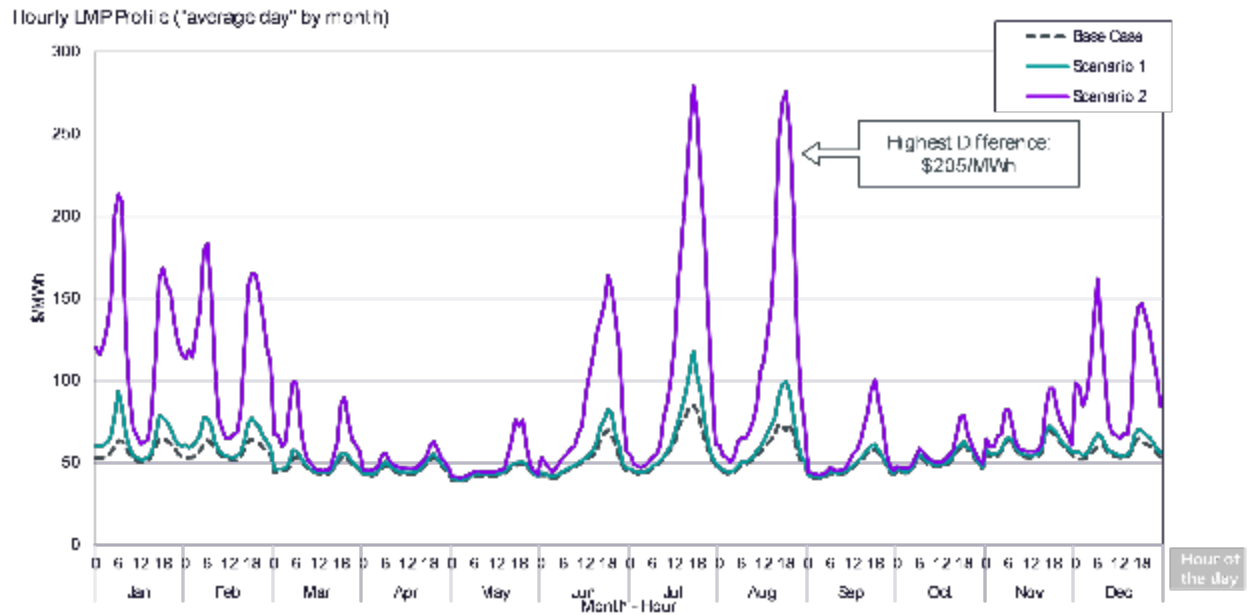


Figure 2. Hourly LMP profiles by month

These results indicate that the incremental load exacerbates price impacts during periods when customers are already exposed to higher electricity costs, compounding bill impacts during extreme weather conditions.

4. Geographic Distribution of Impacts Within Delaware

In Scenario 1, the data center interconnects in northern Delaware, yet the largest percentage increases in LMPs are observed in central and southern portions of the state. Nodes in Kent and Sussex counties experience increases on the order of 15 to 17 percent relative to the Base Case, while northern nodes near Red Lion see comparatively modest changes. In Scenario 2, southern nodes experience significantly higher increases to the order of 98 to 212 percent relative to the Base Case.

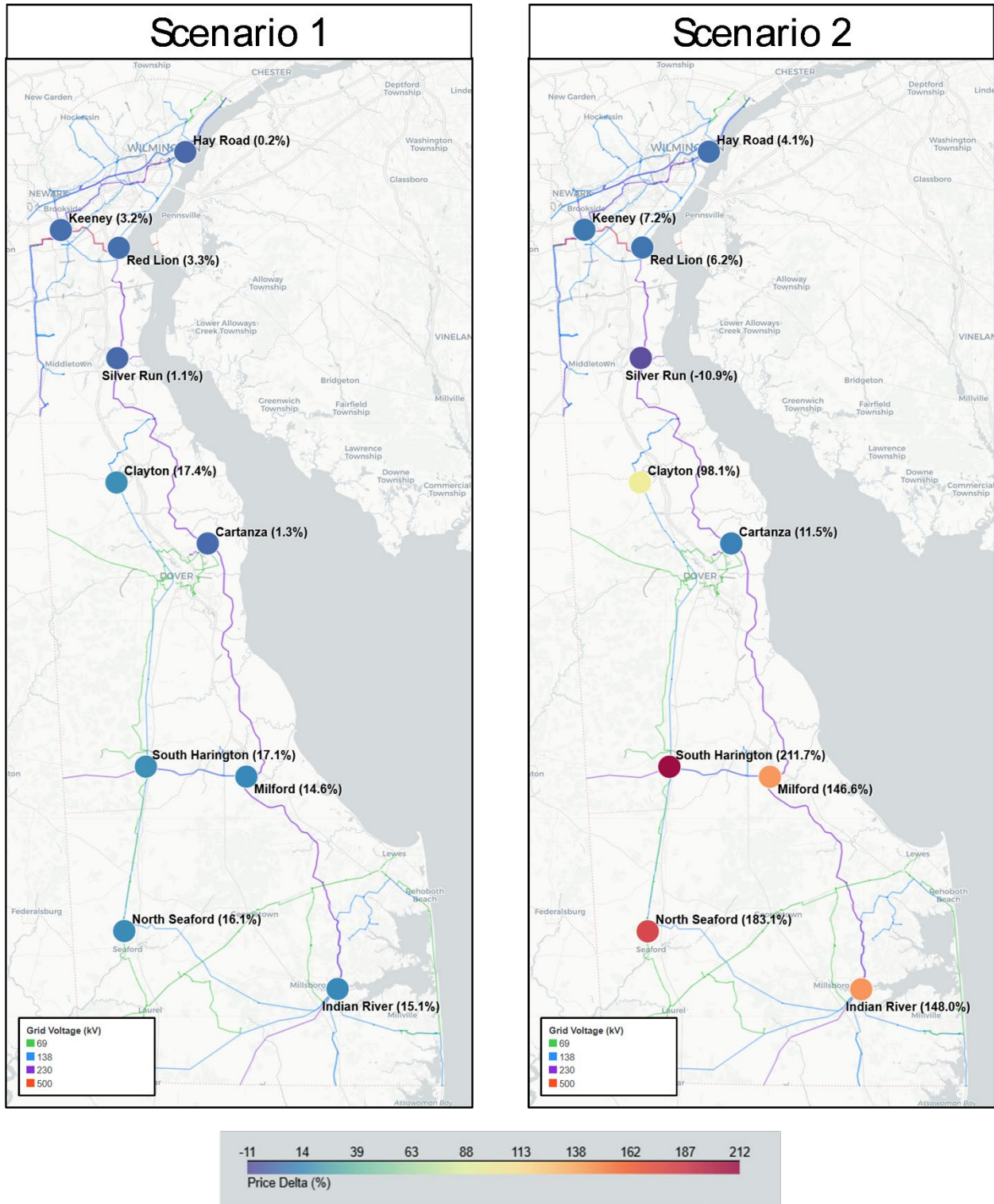


Figure 3. LMP Changes by Node Compared to Base Case for Scenario 1 and Scenario 2

These spatial differences reflect transmission bottlenecks and Delaware’s reliance on north-to-south power transfers. Increased congestion limits the ability to deliver lower-cost

power to southern Delaware, resulting in higher reliance on higher marginal cost generation in those areas.

5. System Operations and Reliability Considerations

In addition to higher energy costs, the study identified operational impacts that contribute to increased prices and elevated reliability risk. The incremental load places substantial stress on the 500 kV transmission corridor through Red Lion, including a reversal of power flow between Red Lion and Keeney. Sustained flow reversals on major transmission interfaces raise reliability concerns because protection systems are often designed assuming predominant flow in a specific direction. Such changes would require additional contingency and protection studies to ensure secure system operation.

The analysis also found that congestion at Red Lion reduces power flows along the 230 kV corridor serving southern Delaware. Under peak conditions, this resulted in two load-shedding events in Kent County in Scenario 1 that did not occur in the Base Case, indicating increased reliability risk during stressed hours. These operational constraints further contribute to higher LMPs during peak periods.

	Unique Hours of Load Shedding	Load Shed (MWh)
Base Case	0	0
Scenario 1	2	47.51
Scenario 2	322	28,030

In Scenario 2, high levels of load shedding were observed. Total load shed increased more than 500-fold relative to Scenario 1, indicating that the system was unable to reliably serve 2.4 GW of new data center load under the modeled conditions. The magnitude and persistence of this load shedding demonstrated that the system experienced severe stress and operating infeasibilities when subjected to this level of incremental demand. Load shed of this scale may also raise potential concerns regarding voltage stability, particularly given the transmission constrained nature of the affected area.

Load shedding occurred across a diverse set of locations, with impacts observed at nodes distributed throughout Kent and Sussex counties, as well as at nearby nodes at similar latitudes just across the Delaware-Maryland border. These nodes spanned multiple voltage levels, ranging from 230 kV to below 69 kV, indicating that the issue was systemic rather than driven by a single localized weakness or facility outage.

6. Marginal Cost Impacts

Delaware’s standard offer service is impacted by wholesale market outcomes. In this case, the increase in LMPs is an indicator of higher marginal energy procurement costs. Therefore,

higher LMPs from increased local demand will affect all residential, commercial, and industrial customers statewide. In Scenario 1, the analysis estimates an increase of approximately \$92 million per year in marginal wholesale energy costs attributable to the data center load in the DPL region, equivalent to roughly half a cent per kilowatt-hour on average.

	Marginal Cost Increase (Millions)	Percent Change over Base Case
Scenario 1	\$92.1	9.1%
Scenario 2	\$834.5	82.1%

In Scenario 2, results showed that LMPs will increase by approximately 82% over the Base Case. Applied to all non-data center load, this will result in \$742.4 million in incremental marginal costs added to Scenario 1. However, note that a 2.4 GW load increase represents an approximately 58% increase compared to the DPL region’s 2025 peak load. It may be unreasonable to expect such a high volume of energy to be transacted in day-ahead or real-time markets. It is more likely that a large portion of required supply, will be met through self-supply and bilateral contracts particularly by larger, more sophisticated end-use customers. Only 10-25% of total energy is traded on the day-ahead and real-time spot markets. In a constrained system, all three market segments (i.e. self-supply, bilateral contracts and spot markets) will increase in costs, but spot market prices will be impacted in the short term, while the other two segments will reflect impacts in prices over time.

The analysis assumed a fixed transmission and generation topology. In reality, DPL could make changes to transmission topology based on engineering and cluster studies conducted during the process of interconnecting large loads. However, such improvements are typically reliability focused and not aimed at relieving pricing concerns. Please note that these impacts do not include marginal capacity and transmission costs which will also experience price pressure from the addition of large loads in the absence of new generation at the same scale.

B. Reliability Impacts

Grid reliability is a growing concern in Delaware and across the PJM region. Central to this concern is resource adequacy, i.e., the aspect of system reliability that involves having sufficient power resources to meet future load while accounting for uncertainty in both supply and demand. When supply falls short of demand, an outage, or “loss of load,” occurs.

Ensuring that Delaware has a reliable power system will require managing both rapid demand growth and supply constraints. PJM’s 2026 load forecast projects summer peak load will increase by 15 GW, or 10 percent, between 2026 and 2029, driven largely by data

center load.⁶³ Load is expected to grow even faster in the longer term: PJM’s 2026 forecast projects a 39 percent increase in peak load by 2035 and a 53 percent increase by 2040. Large loads account for 86 percent of the increase in PJM peak load between 2026 and 2040, although none of these large load additions are assumed in the current PJM load forecast to be located in Delaware. On the supply side, the region has faced interconnection delays for large-scale-generation projects, global supply chain challenges, and local siting and permitting obstacles. These factors combine to inhibit the ability of new resources to help meet projected demand growth.

1. Analytical Methods and Input Assumptions

Synapse used scenario analysis and the Strategic Energy & Risk Valuation Model (SERVM) to evaluate resource adequacy under different future levels of load growth in 2029, with a focus on assessing the impacts of load growth from data centers built in Delaware. SERVM is a widely used resource adequacy model. SERVM evaluates an electric system through the lens of uncertainty and risk by combining information about past risks—including historical weather, economic forecast error, load uncertainty, unit performance, and other information—and performing thousands of simulations to evaluate the likelihood, magnitude, and economic cost of future reliability events.⁶⁴ For each weather year, SERVM uses historical weather patterns to develop load profiles to estimate how loads would respond if the weather experienced in that particular year were to repeat. These weather years also reflect the changing profiles of renewable resources. SERVM probabilistically models the uncertainty around generator unit availability through the simulation of random unit outage draws. This information is then combined to report metrics related to the frequency of loss-of-load events, event duration, and event magnitude.

Using SERVM, Synapse modeled three scenarios for 2029: a base scenario using PJM’s 2026 load forecast, a second scenario adding 1.2 GW of data center load, beyond what is included in PJM’s 2026 forecast, and a third scenario adding 2.4 GW of incremental data center load in Delaware. These scenarios are intended to represent the uncertainty around the amount of data center load that could materialize by 2029 and are summarized in Table 7. Other load components are identical across scenarios and based on the 2026 PJM load forecast.

⁶³ PJM Resource Adequacy Planning. *PJM 2026 Long-Term Load Forecast Report*. 2026. <https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process>.

⁶⁴ SERVM is developed by PowerGEM. More information about SERVM can be found at: <https://power-gem.co/software/servm-resource-adequacy-planning/>.

Scenario	Additional Delaware Data Center Load	Description
Base	0 GW	PJM’s 2026 load forecast; no additional Delaware data center load modeled
Scenario 1	1.2 GW	Base scenario plus 1.2 GW
Scenario 2	2.4 GW	Base scenario 2.4 GW of Delaware data center load

All three scenarios use identical resource portfolios for 2029. To develop resource capacity assumptions for 2029, Synapse relied on existing resources in the SERVM database, calibrated with Form EIA-860 data on proposed additions, retirements, and coal to gas/oil conversions, as well as Siemens’ modeling inputs. For units listed as “Proposed” in EIA-860, Synapse included resources coming online between 2026 and 2029 and classified as “Construction complete,” “Regulatory approvals received,” or “Under construction.” Like Siemens, Synapse incorporated Reliability Resource Initiative (RRI) resources based on the latest project statuses.⁶⁵

2. Base scenario Reliability Findings

Reliability can be measured in multiple ways. The results for the base scenario are presented in Table 8, alongside descriptions of each reliability metric. All results are presented on a weighted-average basis: while the SERVM estimates reliability impacts in thousands of simulations, each of these simulations has a stated likelihood of occurring. As a result, all results can be combined by weighting the simulation probabilities to estimate the “most likely” outcome. All results are PJM-wide.⁶⁶ Loss-of-load events due to insufficient capacity to meet load can occur anywhere across the PJM region, not just in Delaware.

⁶⁵ RRI project statuses were updated as of March 5, 2026. Selected RRI resources that have withdrawn from the PJM queue were not included in the model.

⁶⁶ This is due to simplifications in the default SERVM topology.

Table 8. Reliability analysis results for base scenario

Metric	Unit	Base Scenario	Description
Additional Data Center Load in Delaware	GW	none -	
LOLE (Loss of load expectation)	days per year	3.2	LOLE describes the number of days per year with firm load shed. This metric does not indicate the magnitude, duration, or number of events. The PJM standard is 1 day in 10 years or 0.1 days per year. ⁶⁷
LOLH (Loss of load hours)	hours per year	10.7	LOLH describes the number of hours per year with firm load shed. This is a measure of the duration of loss-of-load events. There is no defined standard in PJM, but ERCOT uses a standard of 12 hours (allowed to exceed once every 100 years) and SPP uses a standard of 2.4 hours per year. ^{68, 69}
EUE (Expected unserved energy)	GWh	72.5	EUE describes the total quantity of unserved energy per year. There is no defined standard in PJM. Alberta, Canada, for example, uses a standard of 0.8 GWh per year. ⁷⁰
Expected outage duration	minutes	142	The expected outage duration describes the average number of minutes per loss-of-load event. There is no defined standard for this metric in PJM.
Outage maximum magnitude	GW	15.0	The maximum outage magnitude describes the highest amount of unserved load per year. There is no defined standard in PJM. ERCOT, for example, uses a standard of 19 GW once per 100 years or 0.19 GW per year. ⁷¹
Outage maximum magnitude	% of PJM peak load	8.55%	The maximum outage magnitude can be expressed as a percentage of peak load in PJM.
Outage maximum magnitude	# of households with outage for 1 hour	12 million	To get a sense of the scale of the maximum outage magnitude, the event can be expressed in terms of number of households in PJM who would lose power for one hour if an event of this magnitude exclusively affected residential customers. ⁷²

In the base scenario, which incorporates only the data center load that PJM has already included in its latest forecast, the PJM system exceeds the PJM standard reliability metric by

⁶⁷ PJM Resource Adequacy Planning. *PJM Manual 20A: Resource Adequacy Analysis*. 2025. <https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.ashx>, p. 8.

⁶⁸ Ming, Z., D. Delgado. *The Role of Metrics in Determining a Reliability Standard*. Presentation at MISO RA Risk Metrics Workshop. 2024. <https://cdn.misoenergy.org/20240926%20RA%20Risk%20Metric%20Workshop%20Item%2004%20Ming%20E3%20MISO%20Role%20of%20Metrics%20in%20Reliability650106.pdf>.

⁶⁹ The Brattle Group. *Resource Adequacy Requirements: Reliability and Economic Implications*. 2013. <https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf>.

⁷⁰ *Id.*

⁷¹ *Id.*

⁷² This metric is a heuristic to approximate the number of households that would be affected by an outage. It divides the maximum expected event magnitude (MW) by an estimate of energy used hourly per household and assumes the outage would only affect residential customers.

a large margin. Systemwide LOLE, modeled at 3.2, is 32 times worse than the PJM reliability standard of 0.1 event-days per year, meaning the system is expected to experience loss-of-load events far more frequently than what is considered acceptable. At an LOLE of 3.2, the probability of outages occurring is 3.2 events per year, versus the 1-in-10-years standard implied by the 0.1 LOLE metric used by PJM.

Other system metrics, while not in wide use at PJM, illustrate the reliability challenges faced by PJM's projected level of load in 2029. Synapse estimates 10.7 hours of outages, with an average duration of 142 minutes or 2.4 hours. The maximum estimated outage is 15 GW, which is 8.55 percent of PJM's load. Put another way, the load loss in this maximum outage event is equal to 12 million customers losing load for 1 hour.⁷³

As a point of reference, the North American Electric Reliability Corporation (NERC) 2025 Long-Term Reliability Assessment estimates 67 GWh of EUE and an LOLH of 9.97 hours in PJM in 2029.⁷⁴ Although NERC uses a different set of modeling assumptions, these values are both within 10 percent of the Synapse base results.

As discussed later, this level of unreliability carries significant economic consequences.

3. Reliability Impacts of Additional Data Center Load

While the load projected in the 2026 PJM forecast alone has dire implications for system reliability, adding even more data center load worsens an already stressed system. Synapse assessed two "with data center" scenarios, each including additional quantities of data center load (1.2 GW and 2.4 GW, respectively) added to Delaware's grid.

The results for the scenarios with additional Delaware data center load are shown in Table 9.

⁷³ According to EIA Form 861, there were 28 million households in PJM in 2024, with 473,500 in Delaware.

⁷⁴ NERC. *2025 Long-Term Reliability Assessment*. 2026. https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf, p. 92.

Table 9. Reliability analysis results for all scenarios

Metric	Unit	Base Scenario	Scenario 1 (1.2 GW addition)	Scenario 2 (2.4 GW addition)
Additional Data Center Load in Delaware	GW	none	1.2	2.4
LOLE (Loss of Load Expectation)	days per year	3.2	3.9	4.7
LOLH (Loss of load hours)	hours per year	10.7	13.2	16.0
EUE (Expected Unserved Energy)	GWh	72.5	89.5	108.5
Expected Outage Duration	minutes	142	151	159
Outage Maximum Magnitude	GW	15.0	16.2	17.3
Outage Maximum Magnitude	% of PJM peak load	8.55%	9.17%	9.72%
Outage Maximum Magnitude	# of households with outage for 1 hour	12 million	13 million	14 million

As data center load increases across scenarios, Delaware residents and businesses experience a higher likelihood of outages. If an initial 1.2 GW comes online, with no other changes to the electric grid, PJM-wide LOLE increases from 3.2 to 3.9 event-days per year. This outage frequency is 39 times worse than PJM’s reliability standard. If another 1.2 GW of data center load comes online alongside the initial 1.2 GW, LOLE worsens further to 4.7 event-days per year, or 47 times worse than PJM’s reliability standard.

Other system metrics also worsen. With additional data center load, Synapse estimates average aggregate outages increasing by 2.5 to 5.3 hours. The outage time experienced in each event is estimated to increase by 9 to 17 minutes. The maximum expected outage increases by 1.2 to 2.3 GW, or an equivalent increase of another 1 to 2 million households without power for an hour. This approaches half of all households in PJM.

Synapse does not expect these results to align with Siemens’ findings, primarily because the two analyses use fundamentally different models designed to answer unique questions. Siemens employed a nodal-level production cost model with power flow analysis, while Synapse used a probabilistic reliability model designed to capture uncertainty in outage, load, and weather conditions. Key methodological differences include weather-correlated outages (only in SERVM), load inputs and forecast error assumptions, and system topology representations. As a result, the outputs from each analysis are better understood as complementary rather than directly comparable.

4. Economic Impacts of Worsened System Reliability

Power outages have economic impacts on households and businesses. For example, power interruptions could require residential customers to turn on backup power generation or risk food spoilage, stay home from work and school, or relocate temporarily. Businesses might face disruption to production, ruined inventory, or costs associated with mitigating impacts, such as procuring backup generation or relocating.

The value of avoiding electricity losses can be quantified using a value of lost load (VOLL) metric. To calculate the average VOLL per scenario, Synapse used Berkeley Lab’s Interruption Cost Estimate (ICE) Calculator to calculate the average VOLL at each modeled reliability level.⁷⁵ Synapse then multiplied the average VOLL per scenario by the total expected quantity of unserved energy in each scenario to calculate the total expected economic impact across the PJM region. The PJM-wide economic impacts were scaled down using Delaware’s share of PJM annual load in 2029 (2 to 4 percent, depending on the scenario).⁷⁶ This step assumes that Delaware’s share of power interruptions is proportional to its share of PJM’s annual load in 2029.

Table 10 shows the expected economic impacts of power interruptions in each modeled scenario on the overall PJM region, as well as in Delaware specifically. In Scenario 1, Delaware customers face an additional \$260 million in economic impacts in 2029, and in Scenario 2, Delaware customers face an additional \$638 million in economic impacts in 2029. Both values are estimated relative to the base, and are not inclusive of the outage-related costs that may be present in the base scenario (which is estimated to have an LOLE metric 32 times worse than the PJM standard).

Table 10. Expected Economic Impacts of Power Interruptions in 2029				
Scenario	Average value of lost load in \$/kWh	Economic impacts on all PJM customers	Economic impacts on Delaware customers	Incremental economic impacts on Delaware customers, relative to Base
Base	\$186	\$13.5 billion	\$252.6 million	-
Scenario 1	\$198	\$17.7 billion	\$512.3 million	\$259.8 million
Scenario 2	\$211	\$22.9 billion	\$890.8 million	\$638.3 million

Note: All monetary values are reported in 2025 dollars.

One element of uncertainty in this estimate is the distribution of power interruptions across the PJM region. Since Synapse conducted a regional, PJM-wide reliability analysis, its

⁷⁵ In calculating the average VOLL, the number of residential customers relative to commercial and industrial customers in Delaware was based on EIA 861 data from 2024. For more information on the ICE Calculator, see: <https://icecalculator.com/interruption-cost/config/select-states>. In general, it is observed that the VOLL as estimated by the ICE calculator tends to increase as reliability worsens, indicating that customers tend to value reliability more when outages are more frequent or longer lasting.

⁷⁶ Load share percentages were calculated using Table E1 of the 2026 PJM load forecast for DPL and PJM RTO, adjusted to include the additional Delaware data center load modeled in each scenario.

modeling did not specify where these power outages would occur. Delaware's share of power interruptions could be greater or less than its load share. Another dimension is the distribution of power interruptions between residential, commercial, and industrial customers. Each of these customer classes has a different value of lost load, and so a different distribution of which customers face power interruptions could lead to higher or lower total economic impacts. This calculation currently uses data on Delaware's current customer class distribution to produce an average VOLL for all customers. Incorporating the impact of the additional data center load would lead to a greater share of commercial and industrial. This, in turn, would result in a higher VOLL (since these customers tend to face greater economic impacts from power interruptions than residential customers), and would lead to higher outage-related costs.