aes Indiana

2025 Integrated Resource Plan

(IRP)

Volume I

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2025 Integrated Resource Plan (IRP)

Letter from AES Indiana's President

Powering Central Indiana's Energy Future

Across the state and in Central Indiana, we find ourselves at a great inflection point in our energy future. Changing customer needs, perceptions, and the rapid rise of electrification and AI have presented tremendous opportunity to grow our economy and strengthen our communities. For more than a decade, AES Indiana has led a responsible energy transition with a balanced and diverse energy mix to serve our customers' evolving needs, and this IRP is the next step in this journey.

Our 2025 plan builds on this momentum and charts a path to best meet the energy needs of our more than 530,000 customers, reflecting the dynamic changes taking place in our industry and the evolving policy and market conditions. Our approach to powering the future of energy is rooted in planning for two possible outcomes, ensuring we can adapt and deliver by investing in newer technologies, expanding battery storage, and embracing flexibility to meet potential new demands.

Our plan includes a preferred resource portfolio that identifies two options for resource additions. The first set of resource additions will be added to the portfolio regardless of the size and timing of a potential large-load customer, such as a data center. The second set of resource additions will only be added after a large-load customer is contracted. If a large-load customer locates in our service territory, we will add up to 700 megawatts of natural gas and up to 820 megawatts of battery storage.

While the IRP does not consider ratemaking as part of the resource portfolio, early rate analysis shows no negative rate impact to existing customers related to powering data centers that are interested in locating to our service territory. This is possible because, even though more investments are required to serve those customers, we will be able to spread costs over a larger amount of electricity sold and future data center customers paying their fair share. As we progress in our plan, each investment decision in our generation fleet is subject to regulatory and other approvals.

I would like to thank all our customers, partners, suppliers, and stakeholders who engaged in our 2025 IRP process. We know that energy is foundational to improving lives, and as we have for the past 100 years, we will continue to work 24/7 to power what matters most to each and every one of our customers.

Brandi Davis-Handy
President, AES Indiana

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Executive Summary

After a decade of guiding the energy transition with a steadfast commitment to our state's Five Pillars of Utility Electric Service (affordability, reliability, resiliency, stability, and environmental sustainability) and deep focus on our customers' needs, AES Indiana’s 2025 IRP brought unique challenges for our century old utility. With historic growth opportunities in Central Indiana the 2025 IRP evaluated varying levels of large load integration.

Large load customers like data centers are interested in calling central Indiana their home. While AES Indiana currently does not have an energy services arrangement with a large load customer, their decision to locate within AES Indiana's service territory could dramatically increase demand. AES Indiana has a regulatory obligation to serve customers within its territory. AES Indiana is evaluating how to meet this obligation in a current market environment marked by dramatic inflationary pressures and market rule changes.

AES Indiana worked alongside its stakeholders to thoughtfully analyze how to integrate large loads under a variety of market conditions while prioritizing the Five Pillars and risk and opportunity. For the first time, AES Indiana is presenting two preferred resource portfolios to guide resource acquisition through 2032: one to address current customer load electric growth, and another to support large load customers should they choose to site in AES Indiana’s service territory. In the face of significant changes, this approach allows AES Indiana to respond to customer needs flexibly.

Preferred Resource Portfolio and Short-Term Action Plan

AES Indiana has developed a Short Term Action Plan in its 2025 Integrated Resource Plan (IRP) that ensures AES Indiana can confidently provide the most cost-effective generation portfolio option for its more than 530,000 industrial, commercial, and residential customers in Central Indiana and prospective future customers, while maintaining its obligation to meet the requirements of any new customers that decide to locate within its territory.

Given the uncertainty around the timing and number of large-load customers that may locate in AES Indiana’s service territory, AES Indiana has two preferred action plans: the first set of resource additions will be added to the portfolio regardless of the size and timing of a potential large-load customer, and the second set of resource additions will only be added after a large-load customer is contracted. After months of modeling, reviewing, and through four public stakeholder meetings, these preferred portfolios were chosen while taking cost, risk, and uncertainty into consideration – as directed by Indiana State law.

The portfolios are shown in Figure 0-1.

Figure 0-1: Short-Term Action Plan

		2027	2028	2029	2030	2031	2032
Demand Response	No Data Center Load	44	61	107	130	144	152
	Mid DC Load	44	61	105	124	133	138
Energy Efficiency	No Data Center Load	34	57	78	98	116	133
	Mid DC Load	34	57	78	98	116	133
Battery Storage	No Data Center Load		20	20	20	20	40
	Mid DC Load		200	360	580	860	860
Gas CCGT	No Data Center Load						
	Mid DC Load						700
Gas CT	No Data Center Load						
	Mid DC Load						
Gas Reciprocating Engines	No Data Center Load						
	Mid DC Load						
Solar	No Data Center Load						
	Mid DC Load						
Wind	No Data Center Load						
	Mid DC Load						
Summer Capacity Market Purchases/(Sales)	No Data Center Load	2	27	(10)	(15)	(17)	(33)
	Mid DC Load	2	34	49	48	(0)	(50)
Winter Capacity Market Purchases/(Sales)	No Data Center Load	22	41	31	28	32	44
	Mid DC Load	23	(43)	22	49	48	(50)

No Data Center Load: Energy efficiency, demand response, and storage are required to meet existing customer load growth. This portfolio installs 152 MW of firm demand response and 133 MW of energy efficiency by 2032. This preferred portfolio includes up to 20 MW of storage installed capacity by 2028 and up to 40 MW by 2032.

Mid Data Center Load: The second portfolio would install additional resources should large loads commit to AES Indiana's service territory. This portfolio is based on the assumption that the large loads ramp profile reaches 1,500 MW by 2035. This adds 820 MW of battery storage and a 700 MW combined cycle by 2032, when data center load is modeled at about 1 GW.

The 2025 IRP modeled new, generic data center load ramps at different volumes, ramping up linearly over time. If a new data center customer is signed, AES Indiana will calibrate the preferred portfolio to match the new customer's actual projected ramp. Exact resource selection will be subject to approval by the Indiana Utility Regulatory Commission (IURC) in future regulatory filings, as will any associated rate design. Furthermore, resource selection will reflect the specific customer's requirements.

2025 IRP Framework

Every three years, AES Indiana submits an IRP to the IURC that identifies a forward-looking 20-year portfolio of generation that provides safe, reliable, and affordable energy to our 530,000 customers, while considering potential risks and key stakeholder input. The 2025 Integrated Resource Plan is a guide to AES Indiana's future resource decisions rooted in reliability, affordability, risk, sustainability, and economic impact. This months-long process of evaluation and stakeholder engagement provides a meaningful, objective look at our shared energy future.

In the 2025 IRP, AES Indiana evaluated four unique scenarios that represented different world views:

1.) ***Reference Case:*** Represent current market conditions. Tax credits are those under the One Big Beautiful Big Act.
2.) ***Gas Infrastructure Challenges:*** Gas prices are high.
3.) ***High Regulatory: Environmental:*** Return to a world with tax credits for renewables and storage. Proposed regulations under the Clean Air Act 111(b) implementing a 40% capacity factor limit on new combined-cycle units.
4.) ***Stable Markets Scenario:*** Return to a deflationary period where resource costs are more in line with historical trends, and commodity prices are low.

See Figure 0-2.

Figure 0-2: Summary of Scenario Assumptions

Scenario Driver ↓	Reference case	Gas infrastructure challenges	High regulatory: environmental	Stable markets scenario
EPA GHG NSPS	Repealed	Repealed	111B remains in effect	Repealed
Tax credits (ITC/PTC)	OBBBA	OBBBA	IRA reinstatement + extension	OBBBA
AES Indiana load	Base	Base	↑	↓
Natural gas prices	Base	↑	↑	↓
Thermal CAPEX	Base	Base[1]	↑	↓
Renewables CAPEX	Base	Base	Base	↓
EV/distributed solar	↓	Base	↑	Base

For each scenario, AES Indiana modeled four different levels of large load integration:

1.) ***No Data Center Load:*** no additions
2.) ***Low Data Center Load:*** 307 MW by 2032
3.) ***Mid Data Center Load:*** 956 MW by 2032

4.) ***High Data Center Load:*** 1,591 MW by 2032

See Figure 0-3.

Figure 0-3: Data Center Loads (Peak in MW By End of Calendar Year)

	Low	Mid	High
2027	0	50	75
2028	50	231	378
2029	114	413	681
2030	179	594	984
2031	243	775	1,288
2032	307	956	1,591
2033	371	1,138	1,894
2034	436	1,319	2,197
2035+	500	1,500	2,500

Optimizing for each of the four large profiles across four scenarios generated 16 unique sets of resources, or portfolios. These portfolios were frozen and run through all 4 scenarios, yielding 64 model runs. This scenario analysis allowed portfolio performance across a range of policy and commodity futures to be considered. The results were represented and evaluated using a scorecard, designed around the Five Pillars of Utility Electric Service (affordability, reliability, resiliency, stability, and environmental sustainability) and risk and opportunity.

Scorecard Evaluation and Results

The Scorecard helps contextualize performance surrounding resource mixes. See Figure 0-5. Results in the Portfolio Matrix are in Figure 0-4.

Figure 0-4: Scorecard Results

		AFFORDABILITY				RELIABILITY, RESILIENCY, AND STABILITY					RISK & OPPORTUNITY				ENVIRONMENTAL	
Data Center Case	Portfolio	10-Year Levelized Supply Cost	25-Year Supply Cost	10-Year PVRR	25-Year PVRR	Market Purchases + Sales	25-yr energy purchases, % of load	25-yr energy sales, % of load	Dispatchable Capacity, Percent of Peak (2035)	Dispatchable FIRM Capacity, Percent of Peak (2035)	Opportunity (Mean - P5)	Risk (P95-Mean)	Enviro. Scenario Risk	Avg. % Difference from Optimal	Total CO_2 Emissions (25-yr)	Carbon Intensity (25-yr avg.)
	Units →	$2026/MWh	$2026/MWh	2026$MM	2026$MM	%	%	%	%	%	%	%	2026$MM	%	Million Tons	lb/MWh
No Data Center Load	Reference Case	$149	$161	$5,126	$10,092	26%	16%	10%	111%	90%	17%	18%	$234	0%	147	772
	Gas Infrastructure Challenges	$149	$162	$5,154	$10,161	21%	13%	8%	111%	90%	17%	18%	$237	4%	146	766
	High Regulatory: Environmental	$156	$188	$5,906	$15,455	25%	11%	14%	111%	91%	7%	9%	$0	52%	99	523
	Stable Markets Scenario	$149	$161	$5,126	$10,070	27%	18%	9%	111%	90%	17%	19%	$57	0%	153	805
Low Data Center	Reference Case	$144	$151	$5,985	$12,654	23%	15%	8%	121%	99%	14%	18%	$239	3%	183	806
	Gas Infrastructure Challenges	$148	$153	$6,400	$13,047	21%	11%	10%	118%	98%	12%	15%	$970	7%	177	777
	High Regulatory: Environmental	$153	$180	$7,099	$19,827	26%	12%	14%	117%	96%	6%	8%	$0	53%	111	486
	Stable Markets Scenario	$145	$151	$6,020	$12,699	23%	15%	8%	119%	97%	15%	18%	$196	1%	194	854
Mid Data Center	Reference Case	$138	$139	$7,971	$18,187	17%	12%	5%	122%	102%	11%	16%	$658	3%	247	812
	Gas Infrastructure Challenges	$139	$140	$8,220	$18,499	17%	10%	7%	117%	99%	11%	15%	$1,217	6%	232	763
	High Regulatory: Environmental	$151	$174	$10,236	$30,040	21%	10%	11%	118%	98%	4%	6%	$0	60%	117	384
	Stable Markets Scenario	$138	$139	$7,967	$18,266	17%	12%	4%	121%	100%	12%	18%	$209	2%	278	914
High Data Center	Reference Case	$134	$132	$9,975	$23,754	15%	10%	5%	118%	102%	11%	15%	$1,434	3%	295	779
	Gas Infrastructure Challenges	$135	$133	$10,132	$24,032	14%	8%	7%	125%	109%	10%	14%	$1,851	5%	292	770
	High Regulatory: Environmental	$145	$164	$12,246	$37,871	18%	10%	8%	120%	99%	4%	7%	$0	52%	149	394
	Stable Markets Scenario	$134	$133	$9,959	$23,990	14%	10%	4%	133%	112%	11%	16%	$590	2%	333	879

Figure 0-5: Installed Capacity Across Portfolios within Short-Term Action Plan Window

No Data Center Load Portfolios	Resource	2027	2028	2029	2030	2031	2032
High Regulatory: Environmental	Solar	25	25	25	25	25	25
High Regulatory: Environmental	Wind				50	50	350
Reference Case	DR & EE	56	92	143	177	203	226
Gas Infrastructure Challenges		56	92	143	177	203	226
High Regulatory: Environmental		56	92	143	177	203	226
Stable Markets Scenario		51	75	99	120	140	159
Reference Case	Storage		20	20	20	20	40
Gas Infrastructure Challenges			20	20	20	20	40
High Regulatory: Environmental		40	100	100	100	120	120

Mid Data Center Load Portfolios	Resource	2027	2028	2029	2030	2031	2032
Gas Infrastructure Challenges	Solar		50	50	50	50	50
High Regulatory: Environmental	Solar	25	50	50	50	50	50
High Regulatory: Environmental	Wind				350	750	1,250
Stable Markets Scenario	Solar		100	100	100	100	100
Reference Case	DR & EE	56	92	141	173	196	216
Gas Infrastructure Challenges		56	92	143	177	203	226
High Regulatory: Environmental		56	92	143	181	212	239
Stable Markets Scenario		56	92	143	177	203	226
Reference Case	Storage		200	360	580	860	860
Gas Infrastructure Challenges			140	320	320	320	380
High Regulatory: Environmental		40	180	420	640	840	1,120
Stable Markets Scenario			80	180	400	660	700
Stable Markets Scenario	Gas Peaking						240
Reference Case	Gas CCGT						700
Gas Infrastructure Challenges					700	700	700

The Scorecard highlights the following points:

1) *Affordability*

- → The greater the data center load, the larger the future revenue requirement and/or potential investment required on behalf of the utility. This is shown in the PVRR metrics.
- → However, the more sales that costs are spread over, the lower the rate to serve the entire system. See the levelized supply cost metrics. This indicates that if large loads pay for the use of the existing system, there could be downward cost pressures. While the IRP can provide indications of cost pressures, it does not comment on how these pressures would impact different rate classes. Cost allocation and rate design require cost-of-service studies and rate cases. This involves stakeholder engagement and ultimately requires IURC approval.
- → Under current market conditions, the High Regulatory: Environmental resource mixes have the highest system rates. These portfolios bring online more resources to support reliability. Plus, these resources are subject to the tax credits under the One Big Beautiful Bill Act, which are less generous than those previously provided under the Inflation Reduction Act.

2) *Reliability, Resiliency, And Stability*

- → The portfolios were designed to be reliable. At a minimum, they had to meet the MISO required seasonal reserve margin. Capacity purchases were limited to 50 MW per season. Furthermore, energy purchases and sales were limited to 20% of the annual native load.
- → Because of this, all portfolios have dispatchable installed capacity and dispatchable firm capacity in excess of 90% of the 2035 peak load.

3) *Risk and Opportunity*

- → Overall, the High Regulatory: Environmental portfolios have less financial variation, as seen in the stochastic analysis where portfolios were exposed to 100 model runs with various commodity and weather conditions. Those portfolios are more insulated from natural gas price shocks.
- → However, the High Regulatory: Environmental portfolios also cost more compared to the ideal resource mix under current market conditions.
- → The Gas Infrastructure Challenges portfolios experienced the greatest financial risk, should markets transition to a more favorable world for renewables. This is because these portfolios install natural gas sooner, as more efficient units are needed in a high gas price world.
- → As large loads come online, the financial opportunities and risks associated with the portfolio decrease; this is because resource mixes were designed to cover new large loads with generation versus energy purchases.

4) *Sustainability*

- → The more load, the greater the carbon emissions on an absolute basis. However, except for the High Regulatory portfolio, the portfolios' carbon intensities are similar.

Next Steps

AES Indiana is planning for multiple eventualities, every day, with reliability and affordability top of mind. AES Indiana will continue to evaluate the best path forward, update stakeholders, and commit to its required regulatory processes as we work to accelerate the future of energy in Central Indiana.

Section 1: Introduction

AES Indiana provides electricity generation, transmission, distribution, and sales to approximately 531,000 retail customers across Indianapolis and surrounding communities within a 40-mile radius. Its service territory spans roughly 528 square miles.

The company is regulated by both the Indiana Utility Regulatory Commission (“IURC”) and the Federal Energy Regulatory Commission (“FERC”). AES Indiana actively participates in the electricity markets managed by the Midcontinent Independent System Operator (“MISO”). It is a transmission member of Reliability First (“RF”), one of eight Regional Reliability Councils governed by the North American Electric Reliability Corporation (“NERC”). NERC serves as the designated Electric Reliability Organization under the Energy Policy Act of 2005.

Every three years, AES Indiana submits an Integrated Resource Plan (IRP) to the IURC, as required by the Indiana Administrative Code (IAC 170 4-7). The IRP outlines projected electricity demand, identifies potential risks, explores future scenarios, and recommends a preferred resource portfolio to meet anticipated needs over a 25-year horizon. This planning process includes robust stakeholder engagement through a Public Advisory process.

The IRP serves as a strategic framework for future resource decisions, reflecting conditions at a specific point in time. These decisions may evolve based on updated analyses and regulatory developments. Any proposed additions to AES Indiana’s resource portfolio must receive regulatory approval.

1.1 IRP Objective

170 IAC 4-7-4(24)

The goal of AES Indiana’s IRP is to identify optimal resource portfolios that deliver safe, reliable, sustainable, and cost-effective energy to its customers. This planning process incorporates stakeholder input and evaluates potential risks to ensure balanced decision-making. The current IRP covers the study period from 2026 to 2050.

In preparation for the 2025 IRP, AES Indiana conducted a comprehensive bottom-up review of all modeling assumptions and methodologies used in its 2022 IRP. The company engaged stakeholders through four Public Advisory Meetings and four Technical Meetings, fostering a transparent and data-driven approach. This collaborative process informed the development of the IRP’s assumptions and modeling framework, which addresses the diverse challenges facing AES Indiana’s generation fleet over the next 25 years.

As detailed in this report, AES Indiana’s Preferred Resource Portfolio and Short-Term Action Plan were selected using a scorecard methodology. This evaluation considered key criteria including affordability, system reliability, resilience and stability, environmental sustainability, and incorporated a thorough risk assessment.

1.2 Guiding Principles

The guiding principles AES Indiana used in its 2025 IRP decision analysis process are as follows:

1. AES Indiana will comply with IURC Orders, IAC requirements, NERC reliability standards, and FERC-approved MISO tariffs.
2. Costs for supply-side replacement resources were based on responses from AES Indiana's 2024 All-Source Request for Proposals ("RFP"), AES Indiana's Thermal Development RFP, and multiple secondary sources. DSM was modeled as a selectable replacement resource in the capacity expansion analysis, in accordance with IURC rules. Demand-side cost estimates were based on a detailed Market Potential Study ("MPS") and AES Indiana Demand Side Management ("DSM") implementation experience.
3. Modeling was conducted using a reasonable least cost economic basis framework, subject to constraints for market access and resource availability that reflect risk tolerances and current market conditions.
4. AES Indiana tailored its IRP scorecard analysis to evaluate portfolios under a framework that reflects the Five Pillars of Electric Utility Service, as established in Ind. Code § 8-1-2-0.6.

AES Indiana recognizes the following items, among others, may initiate updates to AES Indiana's strategic direction.

- Large load integration – If new loads are located within the AES service territory, AES Indiana will update its forecasts and plan accordingly.
- Technology costs and improvements – Technology characteristics and pricing may need to be updated if market conditions, supply chains, regulatory frameworks, tax incentives, or technology development change.
- Natural gas prices – AES Indiana will closely monitor the potential impacts of the natural gas fleet on its operations.
- Environmental legislation – Proposed or implemented environmental regulations will be reflected.
- MISO capacity accreditation changes – AES Indiana has accounted for projected changes to generator accreditation by including the Direct Loss of Load ("DLOL") methodology. However, given that this has not yet been impacted, the exact impacts may differ from estimates. AES Indiana recognizes that with time, accreditation estimates may be refined. Furthermore, further market changes from MISO are possible.

During the 2022 IRP, the high load forecast did not come close to capturing the potential impacts of data centers. Similarly, it may be difficult for AES Indiana to predict what could happen in the future. AES Indiana, therefore, remains committed to agility and flexibility in long-term planning.

1.3 2025 IRP Improvements

AES Indiana has incorporated several changes in its IRP process for its 2025 IRP based on IURC and stakeholder feedback to its 2022 IRP:

5. AES Indiana created four worldviews, or scenarios, across four distinct load profiles. This results in 16 potential portfolios (resource mixes). Portfolios were subject to all four scenarios. This resulted in 64 model runs for evaluation. Seven additional sensitivities were incorporated to provide further analysis on topics of note to AES Indiana and stakeholders. The depth of the modeling supplied an expansive view of potential risks and opportunities.
6. AES Indiana engaged in extensive collaboration with stakeholders on DSM, which resulted in an agreement on the DSM bundling methodology and an expansion of DR resources modeled in the report.
7. AES Indiana expanded its IRP Scorecard metrics for portfolio evaluation, including the addition of levelized supply costs (system cost in $/MWh) as an affordability metric. AES Indiana also included additional reliability metrics on dispatchable capacity.

Figure 1-1 below provides an overview of the improvements AES Indiana made to its 2025 IRP based on stakeholder feedback and the IURC's Director's Report for AES Indiana's 2022 IRP.

Figure 1-1: Overview of 2025 IRP Improvements

Topic	Comments Summary (not exhaustive)[1]	2025 IRP Improvements
Load Forecasting	→ Calculate normal weather using more recent period trend models, using more than 50 years history to capture climate change effects → Clarity on how EVs and PVs forecasting were calculated.	→ Normal weather was calculated over 20 years from 2004 to 2023; climate change was explicitly included in the load forecast. → AES Indiana contracted with Carnegie Mellon to provide distributed generation and EV low, mid, and high forecasts. Carnegie Mellon's method leveraged spatio-temporal point process model that captures the spatial and temporal dependencies in the growth of DER/EVPV. By integrating conformal prediction with the point process, the improved method provides robust uncertainty quantification for the predicted number of EVDER installations across multiple regions. The model accounts for local adoption patterns, regional infrastructure, and policy impacts, generating probabilistic forecasts that inform grid planning decisions. This is detailed in the report.

[1] https://www.in.gov/iurc/files/Directors-Final-AES-IRP-Report-8-14-24.pdf

DSM Modeling	→ Business survey process did not achieve industry-standard 90/10 statistical significance → Attention to combining unrelated measures and the hourly impact of DSM measures → DSM rate constructs offered little explanation of the design of the time-varying rates	→ AES delivered DSM surveys through company communication systems, resulting in higher survey participation and 90/10 statistical significance. → AES Indiana used LBNL and NREL end-use load shapes to capture the hourly shapes associated with each DSM measure for inclusion in the portfolio modeling. DSM bundles are unique based on the mix of measures comprising the bundle and their associated load shape. → AES Indiana collaborated with its consultants and stakeholders to consider alternative approaches for measure bundling. Energy efficiency measures were bundled within Residential, Commercial, and Income-Qualified sectors. → AES worked with stakeholders to include diverse DR Resource options. Notably, DR bundles were by typology, diversifying the DR selectable options. → AES included TOU rate as an individual selectable bundle. AES included a discussion on how the TOU assumptions.
Scenario & Risk Analysis	→ Necessary that portfolios from all scenarios are tested across various scenarios	→ AES Indiana stressed all portfolios across all scenarios.
Five Pillars	→ AES did not include the average and levelized rate impact in the scorecard evaluation → Useful to show the annual revenue requirement of a candidate portfolio for each year of the planning period.	→ AES Indiana included levelized rate metrics in the scorecard. → AES Indiana showed the annual revenue requirement for each portfolio in the Report in nominal dollars.

1.4 Stakeholder Engagement

170 IAC 4-7-4(30)

The 2025 stakeholder meeting series covered a comprehensive range of topics, including the IRP process, modeling assumptions, data inputs, Market Potential Study ("MPS"), modeling of Demand Side Management ("DSM") and Demand Response ("DR"), strategy and scenario development, risk analysis, modeling outcomes, and Scorecard metric evaluation for portfolio comparison.

AES Indiana met with stakeholders who executed a Nondisclosure Agreement ("NDA") before each Public Advisory Meeting. Stakeholders who attended these four Technical Meetings. See Figure 1-2. It is important to note that Stakeholders with signed NDAs received the complete EnCompass database, allowing them to recreate and run their own modeling. AES Indiana also conducted 16 meetings on demand response and energy efficiency with stakeholders that provided an NDA.

Figure 1-2: IRP Data Sharing

Data Share	Date	Items Shared
Data Share #1	2/12/2025	→ Base Load Forecast → EV&PV Base, Low and High
Data Share #2	7/24/2025	→ New generic large load assumptions → Commodity curves: • Gas Infrastructure • High Regulatory • Reference Case • Stable Markets → High and low load forecast → Replacement resource costs and capacity accreditation
Data Share #3	9/2/2025 & 9/19/2025	→ Encompass IRP Scenario Loader → IRP Revenue Requirement – Reference Case → IRP Capacity Expansion – Net Capacity Position → IRP PVRR Results → EnCompass ERAP Scenarios & PVRR Results
Date Share #4	10/1/2025, 10/6/2025, 10/8/2025 & 10/15/2025	→ IRP Energy Position → Stochastic Data & Summary Results → IRP PVRR Results – Load Factor Sensitivities → IRP EE Resource Capacity → DR Hourly inputs → ERAP V1 EnCompass Scenario Loader → Stable Market Scenario – Blended Capital Costs → Sensitivities for data centers → Final IRP Scorecard

Stakeholder engagement dramatically improved the process. For example, stakeholder involvement led to the creation of the No Data Center Load Cases. It enhanced the modeling of energy-efficiency and demand-response bundles. Based on robust stakeholder discussions, AES Indiana initiated two additional modeling sensitivities and five stakeholder-requested sensitivities, as listed in Figure 1-3.

Figure 1-3: Additional Modeling Sensitivities

	Name	Description
AES Indiana initiated	1. Data center transmission investment	AES Indiana assumed a "Base" level of transmission investment required for the data center loads, which is added outside the model. High and low estimates were also developed to determine the potential impact of the transmission investment associated with interconnecting the new load.
	2. SMR breakeven analysis	SMRs were not selected in any scenario. AES Indiana forced on a new SMR to evaluate the breakeven capital cost required to match the PVRR of the optimized portfolios.
Stakeholder requested	3. Model ERAP instead of RAP for C&I	CAC and EFG requested additional analysis for Enhanced RAP for C&I EE bundles.
	4. Reinstate tax credits for wind and solar in the Reference Case	Clean Grid Alliance requested additional runs with IRA tax credits reinstated in the Reference Case to see if solar and wind get selected.
	5. Model a lower load factor for the data center load	Load factors for the data center load were reduced from 90% (base) to 70% in 5% increments to evaluate the $/MWh impacts of lower energy use while maintaining the same capacity requirement.
	6. Model case where the data center load leaves early	Request for analysis of data center load leaving early (e.g., after 10-15 years).
	7. Modify thermal costs in the Stable Markets scenario to reflect higher near-term pricing	The Stable Market scenario reflects lower CAPEX for all new capital resources starting in Year 1. EFG requested a more gradual decrease to reflect higher near-term costs, particularly for thermal resources.

AES Indiana also conducted four public stakeholder meetings. See Figure 1-4. These meetings were open to anyone.

Figure 1-4: Public Stakeholder Meetings

Date	Items covered in meeting
January 29, 2025 (link)	IRP Kick-off; Load Forecasting; Electric vehicle and distributed solar
July 24, 2025 (link)	RFP overview; New resource costs; DSM bundles; IRP scenarios and modeling framework; Fundament curves
September 10, 2025 (link)	IRP modeling framework review; Capacity expansion results; Reference Case cost
October 22, 2025 (link)	IRP scorecard and results; Sensitivity analyses; Preferred Plan; Short-term action plan

1.5 Contemporary Issues

170 IAC 4-7-4(17)

AES Indiana participates in the IURC's IRP Contemporary Issues Technical Conference held each year. Topics in 2025 include data center forecasts, implementation of the MISO reliability-based (sloped) demand curve, capacity expansion modeling, considerations for large load interactions, and coordination across planning processes. Additionally, AES Indiana had representatives at the IEA conferences, the Indiana Energy Conference, the Women in Energy Conference, the Midcontinent Energy Summit, and Governor Braun's Nuclear Energy Summit. The Company enjoys participating in these conferences, as they always cover current, relevant topics for Indiana utilities and stakeholders.

Section 2: Reliability – Resource Adequacy

170 IAC 4-7-6(b)(3)(B) and 170 IAC 4-7-6(b)(4)(E)

As the MISO generation resource mix changes, it has become increasingly critical to evaluate and ensure that customers will receive energy during peak periods or system emergencies. AES Indiana looked to MISO and work performed by other utilities for guidance on measuring and evaluating the reliability attributes of the IRP portfolios.

2.1 Resource Adequacy

Resource Adequacy is the ability of generation resources to reliably serve electric demand during peak or reasonably foreseen electric conditions. A utility achieves resource adequacy by possessing sufficient supply-side and demand-side resources to satisfy forecasted future loads. The IRP process focuses on developing potential resource portfolios needed to meet two different types of customer needs: energy use and peak demand. Energy use is measured in megawatt-hours ("MWh") to reflect the cumulative electricity used over time. Peak demand is the highest hourly usage during a defined time period and is measured in megawatts ("MW"). The Resource Adequacy analysis serves as the foundation of the IRP process to create resource portfolios that meet the quarterly forecasted peak demand throughout the 20-year study period. The energy contributions of each resource depend on the economic dispatch model results and the renewable generation profiles in each scenario. Each scenario includes a set of input assumptions based on varying potential futures and related risks, such as commodity prices, environmental policy changes, and increased or decreased load growth. The scenarios are described in Section 8.4.2 of this IRP.

For the purpose of IRP planning and consistent with MISO guidance, AES Indiana captures Resource Adequacy assumptions using two criteria: seasonal planning reserve margin requirements and resource accreditation/capacity credit.

2.1.1 Current Resource Adequacy Construct

AES Indiana participates in MISO's resource adequacy (or capacity) construct as outlined in Module E-1 of MISO's FERC-approved tariff. AES Indiana, not MISO, is responsible for resource adequacy and developing long-term resource plans pursuant to 170 IAC 4-7.

To calculate a utility's capacity requirement for MISO's capacity construct, MISO establishes a Planning Reserve Margin ("PRM") based on its Loss of Load Expectation ("LOLE") Study. This value is modeled to represent the margin above the utility's forecasted peak load for the North American Electric Reliability Council's (NERC) reliability standard of one day of loss of load in 10 years. For Planning Year 2025-2026, the Summer PRM was 7.9% as calculated in the LOLE Study.[2] This means that if all utilities in the MISO footprint carried an average of 7.9% reserves, the expectation would be that every 10 years, there would be no more than 24 hours of loss of

[2] MISO's Planning Year 2025-2026 Loss of Load Expectation Study Report https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

load events within the footprint resulting from peak load exceeding resources available at peak. The PRM is meant to account for forecast error and uncertainty. When the PRM is applied to the forecasted demand at time of MISO Peak, the result is the Planning Reserve Margin Requirement ("PRMR"). MISO performs this process for each of the four seasons.

This IRP was conducted to ensure capacity and energy adequacy across all four seasons.

Figure 2-1: Planning Reserve Margin by Season for PY 2025/2026

PRM (%) Summer	7.9%
PRM (%) Fall	14.9%
PRM (%) Winter	18.4%
PRM (%) Spring	25.3%

To meet the PRMR, resources are assigned Seasonal Accredited Capacity ("SAC") values that reflect their expected availability during peak load. If all resources collectively meet the PRMR, the Resource Adequacy metric is achieved. Alternatively, a short position can be resolved by purchasing capacity in the MISO Planning Resource Auction ("PRA").

Thermal resources receive SAC values based on an annual Generation Verification Test Capability ("GVTC") rating, which is discounted to a three-year rolling average availability rating ("XEFORd").

Wind capacity credit is currently calculated using Effective Load Carrying Capability ("ELCC"), which accounts for the probabilistic shortfalls of wind generation coinciding with peak load in the MISO footprint. Due to a mismatch between low wind production during high-load periods, wind is given a much lower capacity credit than thermal generation.

Similarly, most solar production does not occur during peak load. MISO currently provides solar resources capacity credit of 50% of its nameplate capacity for each solar resource's first year of operation, and future years' capacity credit is based on historical performance. Refer to Section 6.2.2 for more details on how solar capacity credit is being treated in AES Indiana's 2025 IRP.

2.1.2 Future Resource Adequacy Construct: Direct Loss of Load

MISO plans to implement Direct Loss of Load (DLOL) Accreditation in Planning Year 2028-2029. MISO believes that performing accreditation by resource class will improve accuracy. At a high level, the impact will be lower Planning Reserve Margins paired with lower Resource Accreditation. For purposes of the IRP, AES Indiana has incorporated DLOL values and DLOL-adjusted Planning Reserve Margins into projections for the future.

Figure 2-2: Indicative DLOL Planning Reserve Margins[3]

Summer	2.9%
Fall	4.1%
Winter	6.2%
Spring	2.1%

MISO has provided estimated values for the 2028-2029 Planning Year, and they will update the accreditation for wind, solar, and thermal generation every year.

Load Modifying Resources ("LMR") are demand response programs that can respond to emergency conditions for at least 4 hours and receive MISO capacity credit. In the seasonal construct, the credit received can vary by season, such as for Cool Cents, AES Indiana's air conditioning load management program.

AES Indiana plans for a combination of these resource types to meet its PRMR in the future. Please see Section 6.2 for the Capacity Credit and DLOL planning assumptions used in this IRP for the replacement generation resources.

2.2 Fuel Procurement

170 IAC 4-7-4(20)

AES Indiana procures and manages a reliable supply of fuel for its generating units at the lowest cost reasonably possible, consistent with maintaining low busbar cost and compliance with all environmental requirements and guidelines. Busbar costs reflect those costs needed to produce a kilowatt of energy at the production facility. They do not include transmission or substation expenses.

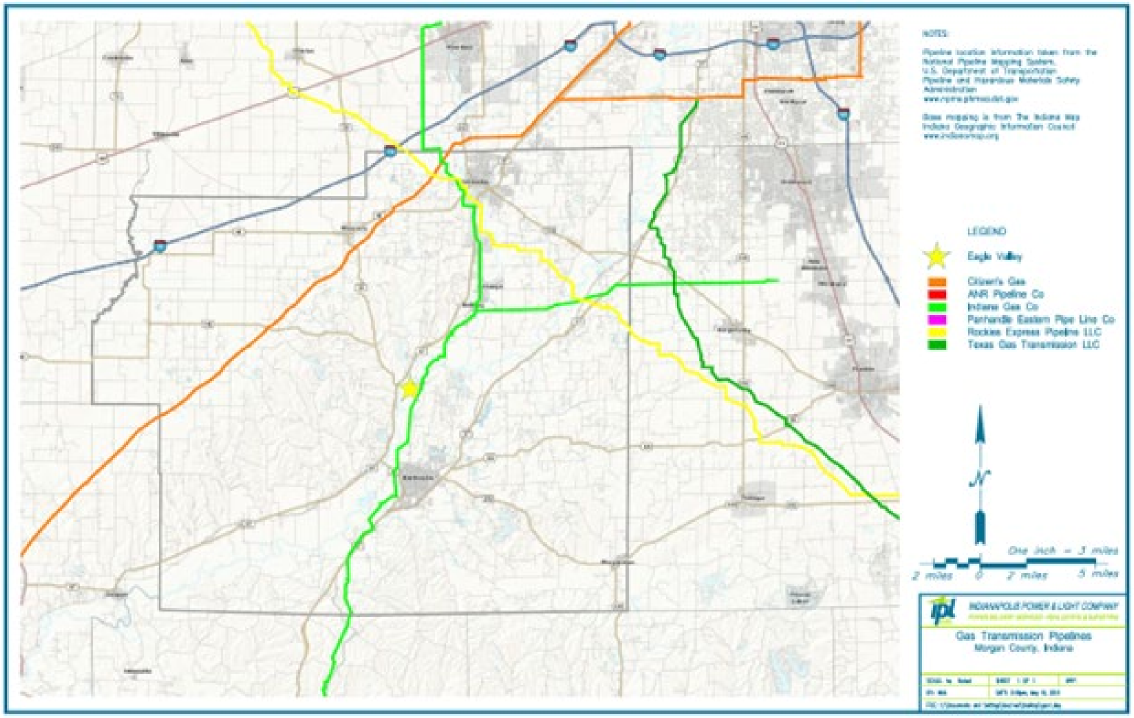
Natural gas ("NG") is currently purchased as a combination of hedges, baseload, and daily spot purchases from several suppliers for its NG-fired portfolio. Harding Street Station ("Harding Street"), Georgetown Generating Plant ("Georgetown"), and Eagle Valley are the currently active NG-fired units. In 2026, Petersburg Units 3 and 4 will be converted to NG-fired units as planned in the 2022 IRP. The hedging program was recently updated during an FAC proceeding to reflect this change, while continuing to use a combination of baseload hedges, including fixed-price, index, and daily purchases, to supply natural gas to the portfolio.

AES Indiana maintains a robust firm pipeline transportation portfolio to ensure reliable, diverse, and easily accessible natural gas for our units. This portfolio includes transportation on Texas Gas Transmission ("TGT"), Rockies Express Pipeline ("REX"), Panhandle Eastern Pipeline ("PEPL"), Trunkline ("Trunk"), and Midwestern Gas Transmission ("MGT"). This diverse portfolio allows for natural gas procurement across various production zones around the United States,

[3] https://cdn.misoenergy.org/Indicative%20DLOL%20Results%20PY%202025-2026667100.pdf

more opportunities for hedging, and provides firm service to our NG-fired units. The TGT contracts give AES Indiana scheduling flexibility to draw or hold a limited quantity of natural gas to address unexpected unit starts and stops and mitigate fuel availability risks. Figure 2-3 is a map of gas transmission around AES Indiana's Eagle Valley CCGT.

Figure 2-3: Gas Transmission Map Near Eagle Valley CCGT



Georgetown and Harding Street units are used for peaking needs, and AES Indiana has determined that firm transportation is valuable for providing reliability to those units, especially during the winter period. AES Indiana has procured on-system storage from Citizens Gas to mitigate the swings that naturally occur in peaking units and provide a source of firm supply. AES Indiana contracts with Citizens Energy Group for firm redelivery and balancing services to the generating units located at the Harding Street and Georgetown plants, and with Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CenterPoint") for firm redelivery to the Eagle Valley CCGT. Petersburg Units 3 and 4 will be directly connected to MGT, where AES Indiana has taken out firm transportation to ensure reliable service.

Section 3: Transmission Planning

170 IAC 4-7-6(a)(5), 170 IAC 4-7-6(b)(3)(B), 170 IAC 4-7-6(b)(4)(A)-(B), and 170 IAC 4-7-6(b)(4)(D)-(E)

3.1 Transmission System Overview

AES Indiana provides electric power to the city of Indianapolis and portions of the surrounding counties as a member of Midcontinent Independent System Operator ("MISO"). The AES Indiana transmission system includes 345 kV and 138 kV voltage levels. The AES Indiana transmission system consists of approximately 458 circuit miles of lines at 345 kilovolts ("kV"), 408 circuit miles of line at 138 kV, and associated substations. The 345 kV system consists of a 345 kV loop around the city of Indianapolis and 345 kV transmission lines connecting the AES Indiana service territory to the Petersburg Generating Station ("Petersburg") in southwest Indiana. At Petersburg, AES Indiana has 345 kV interconnections with Indiana Michigan Power Company ("AEP")[4] and Duke Energy Indiana, LLC ("DEI"), and 138 kV interconnections with DEI, Hoosier Energy Rural Electric Cooperative, Inc. ("HE"), and CenterPoint within the MISO footprint. In the Indianapolis area, AES Indiana has 345 kV interconnections with AEP and DEI and 138 kV interconnections with DEI and HE. Autotransformers connect the 345 kV network to the underlying AES Indiana 138 kV network transmission system, which principally serves AES Indiana load.

AES Indiana's electric transmission facilities are designed to provide safe, reliable, and reasonable least cost service to AES Indiana customers. As part of this transmission system assessment process, AES Indiana participates in and reviews the findings of assessments of transmission system performance by regional entities, including MISO and Reliability First ("RF") as it applies to the AES Indiana transmission system. In addition to the summer peak demand period, which is the most critical for AES Indiana, assessments are performed for a range of demand levels, including winter seasonal and other off-peak periods. For each of these conditions, sensitivity cases may be included in the assessment.

3.2 Transmission Planning Process

170 IAC 4-7-4(24)

As a NERC registered Transmission Planner ("TP"), AES Indiana performs an annual transmission reliability assessment to ensure that the NERC performance requirements are met. Additionally, AES Indiana participates in assessments of transmission system performance performed by MISO and RF.

As a member of MISO, AES Indiana actively participates in the MISO Transmission Expansion Plan ("MTEP") process with MISO functioning as the NERC registered Planning Coordinator ("PC"). MISO annually performs MTEP studies to facilitate a reliable and economic transmission planning process.[5] The AES Indiana assessment and MTEP study process includes identification

[4] AEP ties to the PJM footprint.

[5] The MISO MTEP analysis may be found on the MISO website at URL: https://www.misoenergy.org/planning/planning/mtep21/.

of transmission issues and potential solutions to those issues. AES Indiana studies its local system and submits any local upgrades to MISO. The local upgrade projects are then submitted to MISO for planning review ensuring no harm is done to the larger regional transmission system. MISO through either the MTEP or other study processes may propose additional transmission system projects or other upgrades that are not reliability based but are economically based to relieve congestion. For potential economic projects, MISO assesses costs and benefits to ensure that costs allocated are commensurate with benefits received. Factors in the cost/benefits analysis include: the value of congestion, fuel savings, reductions in operating reserve needs, system planning reserve margins, and transmission line losses of a proposed transmission project or portfolio. Through the MTEP, MISO ensures that transmission is developed system-wide through one uniform planning process that coordinates system needs to minimize costs. Generator interconnection requests (additions or material modifications) to the AES Indiana system would be coordinated and studied through the MISO Generation Interconnection Process. Generator retirements would be studied through the MISO Attachment Y process. AES Indiana actively participates in these MISO processes to ensure that the transmission system meets the performance requirements.

AES Indiana's FERC Form 715 is submitted annually by MISO to FERC. The latest FERC Form 715 was based on MTEP 24 studies, which contain the most recent power flow study available to AES Indiana including interconnections. In MTEP 24, MISO conducted studies using models for 2026 Spring Light Load, 2026 Summer Peak, 2029 Spring Light Load, 2029 Summer Shoulder, 2029 Summer Peak, and 2034 Summer Peak. MTEP 25 studies are being finalized.

Finally, AES Indiana and MISO utilize the latest internal customer load forecast, in conjunction with current and future system configurations, generator dispatches, and system transactions (as necessary), as a basis for the aforementioned system planning and reliability studies.

RF also performs seasonal, near-term, and long-term assessments of transmission system performance conditions based on information from each transmission planner, including both MISO and AES Indiana. The transmission system seasonal assessment summarizes the projected performance of the bulk transmission system within RFs footprint for the upcoming summer peak season and is based upon the studies conducted by RF staff, MISO, PJM Interconnection, L.L.C. ("PJM"), and the Eastern Interconnection Reliability Assessment Group ("ERAG"). As an entity within the reliability region of RF, AES Indiana actively participates and reviews the studies.

3.3 Transmission Planning Criteria

170 IAC 4-7-4(27)

AES Indiana transmission system is planned to meet the performance requirements based on system-specific transmission planning criteria, NERC reliability standards, distribution planning requirements, and other considerations, including, but not limited to, load growth, equipment retirement, decrease in the likelihood of major system events and disturbances, equipment failure, or expectation of imminent equipment failure.

Changes or enhancements to transmission facilities are considered when the transmission planning criteria are not expected to be met and when the issue cannot feasibly be alleviated by sound operating practices. Any recommendations to either modify transmission facilities or adopt certain operating practices must adhere to good engineering practice.

A summary of AES Indiana transmission planning criteria follows.[6] AES Indiana transmission planning criteria are periodically reviewed and revised.

- Identification of planning seasons for which seasonally dependent variables are adjusted as input into the MISO models for the MTEP.
- Limit transmission facility voltages under normal operating conditions to within 5% of nominal voltage, under single contingency outages to 5% below nominal voltage, and under multiple contingency outages to 8% below nominal voltage. In addition to the above limits, generator plant voltages may also be limited by associated auxiliary system limitations that result in narrower voltage limits.
- Limit thermal loading of transmission facilities under normal operating conditions to within normal limits and under contingency conditions to within emergency limits. New and upgraded transmission facilities may be proposed at 90% of the facility normal rating.
- Maintain stability limits, including critical switching times, to within acceptable limits for generators, conductors, terminal equipment, loads, and protection equipment for all credible contingencies, including three-phase faults, phase-to-ground faults, and the effect of slow fault clearing associated with undesired relay operation or failure of a circuit breaker to open.
- Install and maintain facilities such that three-phase, phase-to-phase, and phase-to-ground fault currents are within equipment withstand and interruption rating limits established by the equipment manufacturer.
- Provide adequate dynamic reactive capacity to support transmission voltages under contingency outage or other abnormal operating conditions.
- Design transmission substations such that the operation of substation switching involved with the outage or restoration of a transmission line does not also require the switched outage of a second transmission line. Design 345 kV transmission substations connecting to generating stations such that maintenance and outage of Facilities associated with the generation does not cause an outage of any other transmission Facilities connected to the substation. Coordinate planning studies and analyses with customers to provide reliable service as well as adequate voltage and delivery service capacity for known load additions.

[6] The AES Indiana Transmission Planning Criteria can be found on the MISO website at https://cdn.misoenergy.org/IPL%20TO%20Planning%20Criteria108233.pdf.

- → Consider long-term future system benefits and risks in transmission facility planning studies.

AES Indiana transmission facilities are also planned and coordinated with the following reliability criteria: the reliability standards of NERC including the Transmission System Planning Performance Requirements ("TPL") standards, Modeling Data Analysis ("MOD") standards, and Facility Ratings ("FAC") standards.[7]

The NERC TPL-001-5 Planning Events (Contingencies) that the transmission system is assessed to meet the performance requirements include the following:

- → System performance under normal (no contingency) conditions (Category P0).
- → System performance of the Bulk Electric System for the loss of one of the following elements: Generator, transmission circuit, transformer, shunt, or single pole of a direct current ("DC") line (Category P1).
- → System performance of the Bulk Electric System for the loss of one of the following elements: Opening of a line section w/o a fault, bus section fault, or internal breaker fault (Category P2).
- → System performance of the Bulk Electric System for loss of multiple elements: Generator and a generator, transmission circuit, transformer, shut, or single pole of a DC line (Category P3).
- → System performance following the loss of multiple Bulk Electric System elements caused by a stuck breaker attempting to clear a fault on a generator, transmission circuit, transformer, shunt, or bus section (Category P4).
- → System performance following the loss of multiple Bulk Electric System elements due to a delayed fault clearing due to the failure of a non-redundant protection system protecting the faulted element to operate as designed for one of the following: generator, transmission circuit, transformer, shunt, or bus section (Category P5).
- → System performance of the Bulk Electric System for loss of multiple elements: Transmission circuit, transformer, shunt, or single pole of a DC line (Category P6).
- → System performance of the Bulk Electric System for loss of multiple elements for circuits on common structure or loss of a bipolar DC line (Category P7).

3.4 Transmission System Performance Assessment

Individually and combined, the transmission performance assessments performed by AES Indiana, MISO, and RF demonstrate that AES Indiana meets the system performance requirements of NERC summarized above. From these transmission performance assessments, the AES Indiana transmission system is expected to perform reliably and with continuity over the long term to meet the needs of its customers and the demands placed upon it.

[7] The NERC reliability standards may be found on the NERC website at http://www.nerc.com.

The following is a summary of AES Indiana's transmission system performance.

→ AES Indiana transmission performance analysis using dynamic simulations for stability as evaluated under the NERC Transmission System Planning Performance Requirements ("TPL") reliability standards shows no evidence of system or generator instability.

→ AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows a few localized thermal violations appearing on AES Indiana lines and transformers resulting primarily from multiple element outages of internal AES Indiana transmission facilities. These overloads will be mitigated via operational procedures.

→ AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows transmission voltages in the expected range on AES Indiana facilities.

→ AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows expected loss of demand that is planned, controlled, small, and localized.

→ AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of curtailed firm transfers.

→ AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of area-wide cascading or voltage collapse.

→ Applicable operating and mitigation procedures, in conjunction with planned major transmission facility additions and modifications, result in transmission system performance which meets the requirements of the NERC TPL reliability standards.

3.5 Advanced Transmission/Grid Enhancing Technologies

AES Indiana is actively evaluating new transmission technologies to improve the safety, reliability, and affordability of our system. Advanced Transmission Technologies ("ATT") such as dynamic line rating, advanced power flow controllers, topology optimization, and advanced conductors are new tools in the transmission planning toolbox that can be applied to unique transmission use cases and can be faster to deploy and more cost effective than traditional transmission solutions.

To advance our understanding of ATTs, AES Indiana partnered with LineVision, a leading dynamic line ratings ("DLR") provider, to install 42 sensors across five transmission lines in AES Indiana and AES Ohio in late 2023.[8] AES Indiana's DLR system combines non-contact line sensors that monitor critical spans on three transmission lines with weather conditions and engineering data to deliver a 240-hour forecast of line capacity ratings to inform transmission operations. After one year of deployment, the data show DLR provided an average of 43% capacity increase on AES Indiana's 345kV line over existing static ratings. Importantly, the data indicate that the calculated hourly capacity of transmission lines monitored by dynamic line rating fluctuates based on actual, real-time environmental conditions. For example, DLR improved situational awareness of the line capacity during hot and low wind periods in the summer, indicating lower line capacity ratings compared to static ratings that rely on assumptions for weather conditions. The next phase of AES Indiana's DLR deployment will integrate the ratings into the transmission energy management system to bring these benefits to the real-time operation of the system. This phase is planned to coincide with AES Indiana implementation of ambient adjusted ratings ("AAR") in accordance with FERC Order 881.

In addition to DLR, AES Indiana has evaluated the use of advanced conductors for both new transmission and reconductoring applications. Composite conductors such as ACCC and TS Conductor were evaluated. While ATTs have the potential to improve the efficiency, reliability, and capacity of the transmission system, these tools alone cannot generate electricity. Generation resources remain essential to create and supply the energy that flows through the transmission network, making ATT a complement to, rather than a substitute for, robust generation portfolios.

[8] AES and LineVision release results of study assessing largest single deployment of Dynamic Line Ratings in the US | AES Indiana

Section 4: Distribution System Planning

4.1 Distribution System Overview

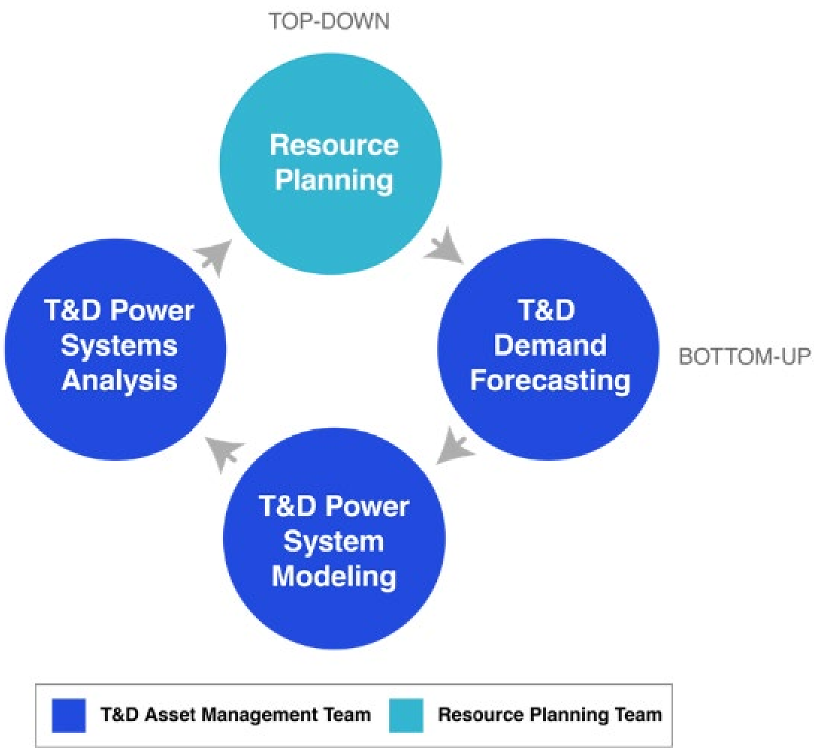
The distribution system consists of 4,208 circuit miles of underground primary cables and 3,619 circuit miles of overhead primary wire as well as 101 substations. AES Indiana uses a Secondary Network System to serve the City of Indianapolis Central Business District, sometimes also referred to as the "Mile Square." A unique feature of the Secondary Network System is that the loss of a single component, such as a primary feeder or a network transformer, typically will not result in any customer losing power.

4.2 Distribution System Planning Overview

170 IAC 4-7-4(18)

AES Indiana distribution planning works closely with Transmission Planning, Distribution Operations, Engineering, and Field Services teams to develop holistic solutions. Processes are mapped (as illustrated in Figure 4-1) such that Resource Planning and T&D forecasting work off same assumptions for top-down and bottom-up load forecasting. The forecasted generation resources and demands act as inputs to T&D power system modeling and analysis processes with common assumptions. As a result, AES Indiana T&D Planning is building the foundation with an aligned organization, smart grid devices, demand forecasting, and network modeling that will enable AES Indiana to effectively plan for multiple scenarios and test non-traditional solutions based on established planning criteria. Non-traditional solutions could be targeted distributed energy resource ("DER") installations, grid inverter orchestration, or strategic battery placements that could serve multiple purposes for distribution reliability and serve as part of overall capacity plan. AES Indiana is building the core platforms to study these scenarios to ensure implementations can be completed in a safe and reliable manner.

Figure 4-1: Integrated T&D Planning Process



As DERs such as photovoltaic systems, electric vehicles (EVs), charging stations, demand response programs, smart appliances, and energy storage systems continue to grow, AES Indiana is evolving its distribution system planning approach. AES Indiana is actively adopting advanced tools that enable proactive forecasting, modeling, analysis, and management of system needs. This enhanced planning process is illustrated in Figure 4-2.

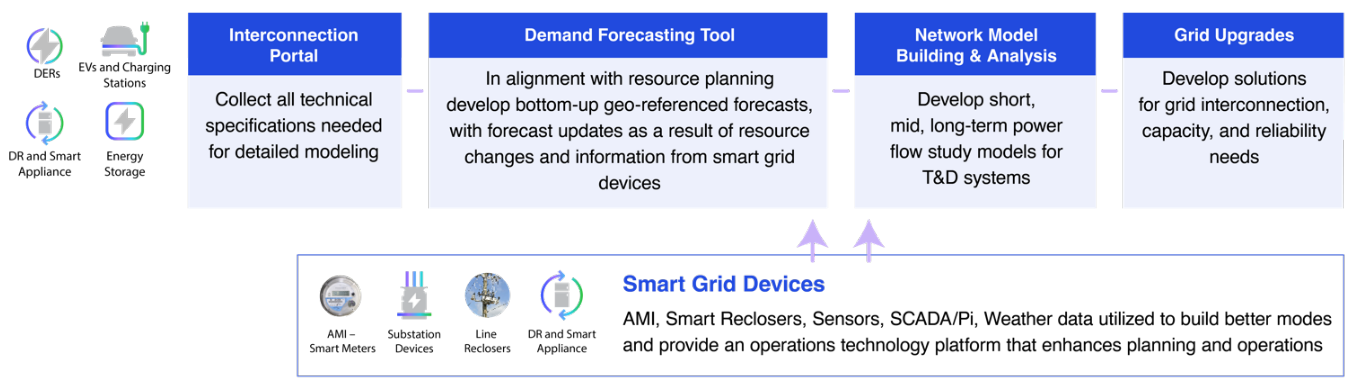
In order to streamline interconnection requests, AES Indiana created a more efficient and user friendly interconnection portal. This replaced paper applications and manual processing allowing for greater automation, seamless communications, and transparency to the customer on their application status. AES Indiana is working to bring cutting edge solutions to this portal by merging our current tools in order to provide a more automated approval and documentation process that minimizes human intervention.

The forecasting model will take the DER data from the interconnection portal as input along with the prior year's load data and corporate demand forecast. LoadSEER, an integrated spatial load/DER/EV forecasting tool developed by Integral Analytics, Inc., is used to create circuit- and transformer-level demand forecasts.

The modeling and analysis process involves building/modifying the CYME model and performing detailed CYME load flow and contingency analyses to ensure AES Indiana's distribution circuits maintain adequate capacity and reliability. Planning criteria have been established that provide the basis for determining the adequacy of the electric distribution system. In situations where the criteria are not met, grid needs are identified. In addition to the traditional distribution system studies, DER hosting capacity analysis will be performed regularly to improve internal and external awareness of available capacity for increasing DER interconnections once a hosting capacity map is created. When a complex DER/Energy storage project is proposed to connect to a distribution circuit, a DER impact study can be performed using CYME to ensure no steady-state and transient criteria is violated.

In the process of grid upgrades, requirements to meet the grid needs are determined, and traditional solutions and/or non-wires alternatives are developed. These solutions are evaluated against short-term and long-term needs/benefits, estimated costs, and physical installation constraints to identify an effective and economical solution with AES Indiana's Engineering and Construction teams. It is worth noting that during the calendar year, it is expected that new service requests or projects will arise that will require modifications to the circuit- or transformer-level forecasts. AES Indiana will, therefore, continually evaluate grid needs throughout the year and make decisions on when to address any grid deficiencies identified outside of the forecast and analysis processes.

Figure 4-2: Distribution Planning Process



4.3 AES Indiana's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan

170 IAC 4-7-4(16)

On March 4, 2020, AES Indiana received IURC approval for its seven-year TDSIC Plan ("TDSIC Plan"). AES Indiana's $1.2 billion TDSIC Plan includes 13 Project Types with defined projects that replace, rebuild, upgrade, redesign, and modernize a wide range of AES Indiana's aging transmission and distribution assets in two thematic areas: Age and Condition, and Deliverability. The 13 Project Types are listed in Figure 4-3 below.

The Age and Condition category (81% of the TDSIC Plan) addresses the many risks posed by aging assets. This category includes the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and rebuilding portions of the Indianapolis central business district. The Deliverability category (19% of the TDSIC Plan) deploys new technologies for advanced distribution management, adds new substation equipment to meet growth-driven capacity requirements, and creates system and operating efficiencies through automation, control functions, and other advanced infrastructure.

Both categories support AES Indiana's ability to maintain and operate the grid in a safe, reliable, and efficient manner. Many of the improvements are focused on giving AES Indiana's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other projects target improvement in overall levels of reliability and integrity.

As part of AES Indiana's TDSIC Plan, certain projects will impact the AES Indiana distribution system, such as the 4 kV Conversion project, the Advanced Metering Infrastructure ("AMI") project, and the Distribution Automation project. These projects contribute to a hardened and resilient grid that better withstands weather impacts and is easier to restore when outages inevitably occur.

AES Indiana is in Year 6 of the 7-Year TDSIC Plan. By the end of 2025, AES Indiana expects to be approximately 85% complete with the TDSIC Plan.

Figure 4-3: TDSIC Project Types

Project Type
Age & Condition Projects
Circuit Rebuilds
Substation Assets Replacement
XLPE Cable Replacement
4kV Conversion
Tap Reliability Improvement Projects
Meter Replacement (AMI)
CBD Secondary Network Upgrades
Static Wire Performance Improvement
Remote End – Breaker Relay/Upgrades
Pole Replacements
Steel Tower Life Extension
Deliverability Projects
Distribution Automation
Substation Design Upgrades

4.3.1 4 kV Conversion

The 4 kV to 13.2 kV conversion plan consists of the replacement of critical transformers and the conversion of radial circuits where 13.2 kV sources are available to avoid overloads on critical substations. This plan is formulated to avoid the failure of adjacent substations that may lead to a cascading outage event. Any equipment with remaining life that is removed due to conversion is used to provide adequate capacity to the remaining 4 kV loads, to provide spare units to cover unforeseen transformer or switchgear failures, or to permit the retirement of equipment that has outlived its useful life and cannot provide reliable service. As of August 22, 2025, AES Indiana has completed 75% of the 4 kV Conversion project.

4.3.2 Advanced Metering Infrastructure

AES Indiana replaced approximately 282,000 residential and small commercial single- and three-phase electric meters over a four-year period through 2023.

The AMI project included in the TDSIC Plan improves safety with the ability to connect, disconnect, and reconnect customers more efficiently through automated technology.

In summary, AES Indiana's AMI project mitigates the risk of a reasonably expected increase in urgent meter replacements due to failed or failing AMI meters. The AMI project enabled the delivery of operational and engineering benefits as well as customer care benefits made possible through an advanced metering network.

4.3.3 Distribution Automation

Distribution Automation has enhanced outage restoration with the additional reclosers and advanced relays allowing sections of circuits to be isolated if there is a fault on the system resulting in fewer customers experiencing a service interruption. In addition, quicker service restoration results when operators may remotely back-feed sections of circuits. Circuits are now operated more efficiently with interactive information received from devices with two-way communication equipment. AES Indiana has remote operation capabilities with feeder relays, reclosers, and capacitors.

As part of the TDSIC Plan, the Distribution Automation project adds distribution infrastructure and replaces older control systems with modern control systems that will increase automation, improve distribution system operation, and enhance safety and reliability. This project also facilitates outage management and service restoration, enables voltage control and associated energy conservation, and improves interconnection with distributed energy resources and new loads. AES Indiana plans to install approximately 1,200 new distribution line reclosers and a new central control system to further increase system automation.

An Advanced Distribution Management System improves reliability with Fault Location, Isolation, and Service Restoration ("FLISR") functionality. The FLISR functionality is expected to eliminate a significant number of customer interruptions per year. FLISR is also expected to reduce the duration of a significant number of interruptions per year to less than 5 minutes.

The Distribution Automation project offers a variety of benefits to the distribution system and AES Indiana's customers. This project improves reliability, enhances safety, and provides voltage management and associated energy conservation as well as modern infrastructure facilitates economic development. The Distribution Automation project also prepares the distribution system for the ongoing development of distributed energy resources and loads. As of August 8, 2025, AES Indiana has completed 92% of the Distribution Automation project.

4.4 Distributed Generation

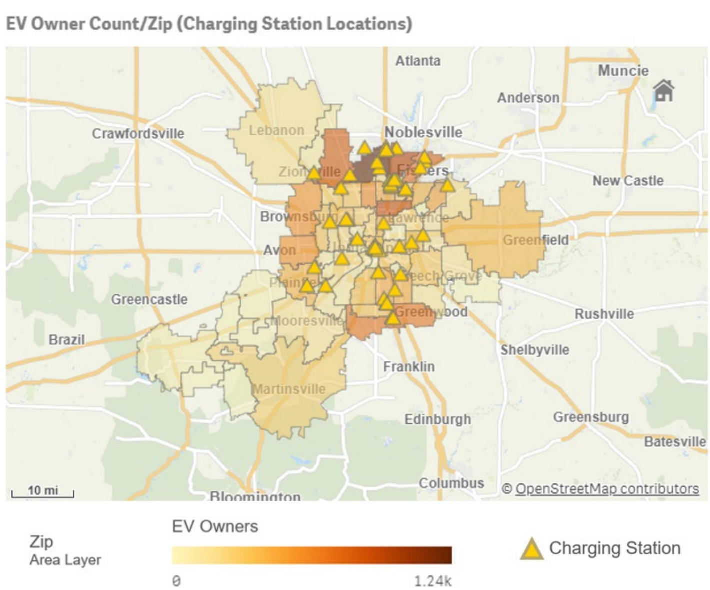
170 IAC 4-7-4(18)

As of August 22, 2025, AES Indiana has 1,589 Level 1 DERs with a total nameplate capacity of 8,889.388 kW, 320 Level 2 DERs with a total nameplate capacity of 24,811.061 kW, and 15 Level 3 DERs with a total nameplate capacity of 40,195 kW.

4.5 Electric Vehicles

Since AES Indiana's 2016 IRP, AES Indiana has worked to develop a process that utilizes internal and external data to map and locate Electric Vehicle ("EV") charging throughout its service territory. See Figure 4-5 below, which shows penetration of EV ownership by zip code per BMV. A higher penetration of EV ownership as shown in Figure 4-4 represents a proxy for associated on-premise charging in absolute terms. In other words, the heat map does not reflect the level of demand or energy associated with electric vehicle charging but defines geographic areas where EV adoption is highest. The existing EV adoption data was an input to a machine learning-based forecasting tool developed in collaboration with Carnegie Mellon University, which utilizes sequential data dynamics from historic data to infer future EV growth trends.

Figure 4-4: Heat Map of EV Adoption by Zip Codes



4.6 Future Smart Grid Expectations

170 IAC 4-7-4(16) and 170 IAC 4-7-4(18)

AES Indiana recognizes that as more DERs are added to its system, their role will increase in future transmission, distribution, and resource planning efforts. These planning efforts inform each other to ensure alignment in the consideration of DERs across the system. AES Indiana is working to build the foundational interconnection, forecasting, modeling, and analysis platforms to implement a smart grid with reliable solutions to the challenges presented by an evolving grid. In the future, as AES Indiana stands up its foundational forecasting, modeling, and analysis platforms, AES Indiana may bring pilot programs forward to test new ways of integrating distribution level resources into the resource plan through strategic DER and smart grid device placement plans using optimal device placement and advanced forecasting tools.

Section 5: Load Research, Load Forecast, and Forecasting Methodology

170 IAC 4-7-4(11)

AES Indiana forecasts its load to be relatively flat, with an average annual growth rate of 0.7% over the IRP planning horizon, before consideration of any future DSM impacts.[9] The Energy Information Administration's ("EIA") projected efficiency trends will continue to show improvements, which are a key contributor to the load trend. This section discusses AES Indiana's projected load growth, exclusive of data center-related load growth. Data center load growth is discussed separately in Section 5.6 entitled Data Center Load Discussion.

5.1 Load Research

170 IAC 4-7-4(13) and 170 IAC 4-7-4(16)

AES Indiana conducts load research based on historical customer load shape data by segment. This information is used in cost-of-service studies and rate design efforts. The granular data aligns with load forecasting data, but it is not a direct input to the forecast at this time. See Attachment 5-1 for the Hourly Load Shapes by Rate and Customer Class from the 2026 Test-Year in AES Indiana's Rate Case (Cause No. 46258). These estimated hourly profiles are based on AMI sample data from January 2022 to August 2024.

Historically, AES Indiana has used a statistical sample of interval meters installed throughout the service territory to collect load research data. This data collection and sampling methodology is discussed in Section 5.1.1 below.

With the high prevalence of AMI meters now installed at AES Indiana services, the Company is considering updating the statistical sample modeling approach mentioned below as an improvement in future rate cases and IRPs.

5.1.1 Load Research Methodology

Rate class hourly profiles are based on large AMI samples randomly selected within four usage stratums for residential rate classes and three stratums for commercial rate classes; this is known as a stratified random sample. Stratum/usage breakpoints are determined using a standard Dalenius-Hodges ("DH") method that calculates stratum breakpoints to minimize overall sample variance. Stratums are based on customers' 2022 annual kWh use. The DH method works well for distributions that are not normally distributed; DH considers the customer size (in terms of usage) as well as the number of customers.

[9] AES Indiana-sponsored DSM impacts have been removed from the load forecast. All future DSM savings will be selected as part of the IRP modeling process.

The Company randomly selected 15-minute interval data for 250 customers in each stratum, for a total of 1,000 customers in each residential rate class and 500 customers in each commercial rate class. The number of sample points was determined by both achieving standard load research precision targets (10% at the 90% confidence level) and LRS's (Itron's load research application) processing capacity. A few customers were ultimately excluded due to missing interval data. A mean per unit expansion (based on the ratio of population to sample customer counts) is used to develop sample loads for the residential rate classes, and a combined-ratio expansion (based on population-average use to sample-average use) is used for the commercial rate classes. The table below shows total customer counts and billed sales (2022), sample size, and the number of strata for the sample.

Figure 5-1 shows the load research sample design. The stratifications are shown for the following rates:

- → Residential General Service ("RS")
- → Residential General Service with electric heat ("RH")
- → Residential General Service with electric water heating ("RC")
- → Small C&I Secondary Service – Small ("SS")
- → Small C&I Secondary Service – Electric Space Conditioning ("SH")
- → Large C&I Secondary Service – Large ("SL")

Figure 5-1: Load Research Design

Rate	Customer Count	Billed MWh	Sample Size	Number of Stratums
RS	253,405	2,374,517	999	4
RH	166,724	2,412,350	913	4
RC	36,266	438,679	994	4
SS	51,249	1,260,777	470	3
SH	3,752	502,382	459	3
SL	4,331	3,264,549	422	3

Hourly 8,760 data is retained in Excel spreadsheets. Historical billing data by account for the demand-billed customers is maintained on an ongoing basis.

5.1.2 Large Commercial Customers

In addition to the residential and C&I meters outlined above, all other large C&I meters have 15-minute profile metering. The 15-minute information provides load research and billing increment data for AES Indiana's demand-metered customers.

5.1.3 Large Industrial Customers

Hourly load profiles for rate classes are estimated from meter data, except for industrial rate classes. The industrial rate class profiles are derived by aggregating all available customer interval data from the load research database.

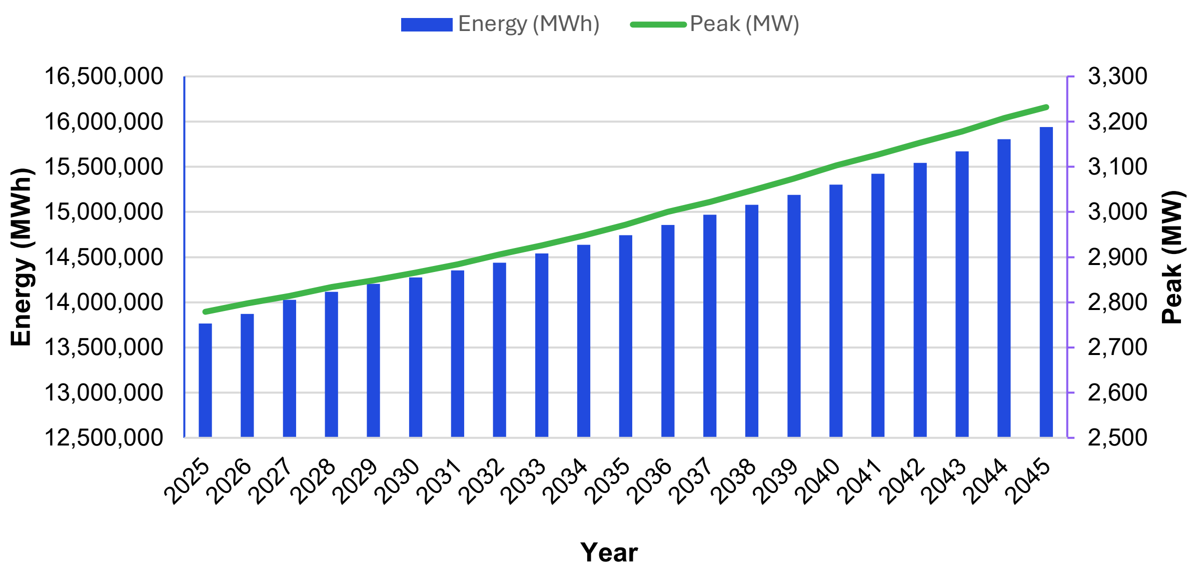
5.2 AES Indiana Load Forecast Overview

AES Indiana hired Itron to develop the 2025 IRP forecast using a bottom-up approach, in which customer-sector sales forecasts for residential, commercial, and industrial sectors are translated into long-term baseline energy and system demand requirements, excluding future impacts from energy efficiency and demand response programs. In the IRP study period, energy efficiency savings[10] are treated as a supply-side resource; thus, the forecast treats all future energy efficiency as selectable and excludes it from the models.

The baseline forecast is adjusted for the expected impact of behind-the-meter solar and electric vehicle charging loads.

Figure 5-2 below shows the forecasted annual energy demand (in MWh) and the associated peaks (in MW). This yields an average annual growth rate of 0.7% in energy and 0.8% in peak demand.

Figure 5-2: Forecasted Annual Energy Demand and Associated Peak Demand[11]



Customer growth, combined with modest growth in average use in the residential sector, results in an expected 1.3% annual load growth rate. AES Indiana anticipates stable customer growth in the residential sector with an average annual growth rate of 1.0% from 2025 through 2045. Load growth in the commercial and industrial sectors is expected to be modest, keeping load relatively flat with an average annual load growth rate of 0.3%.

[10] EE discussed in this Report refers to utility sponsored EE.
[11] Does not include future DSM. Future DSM is modeled as selectable resources in the IRP model.

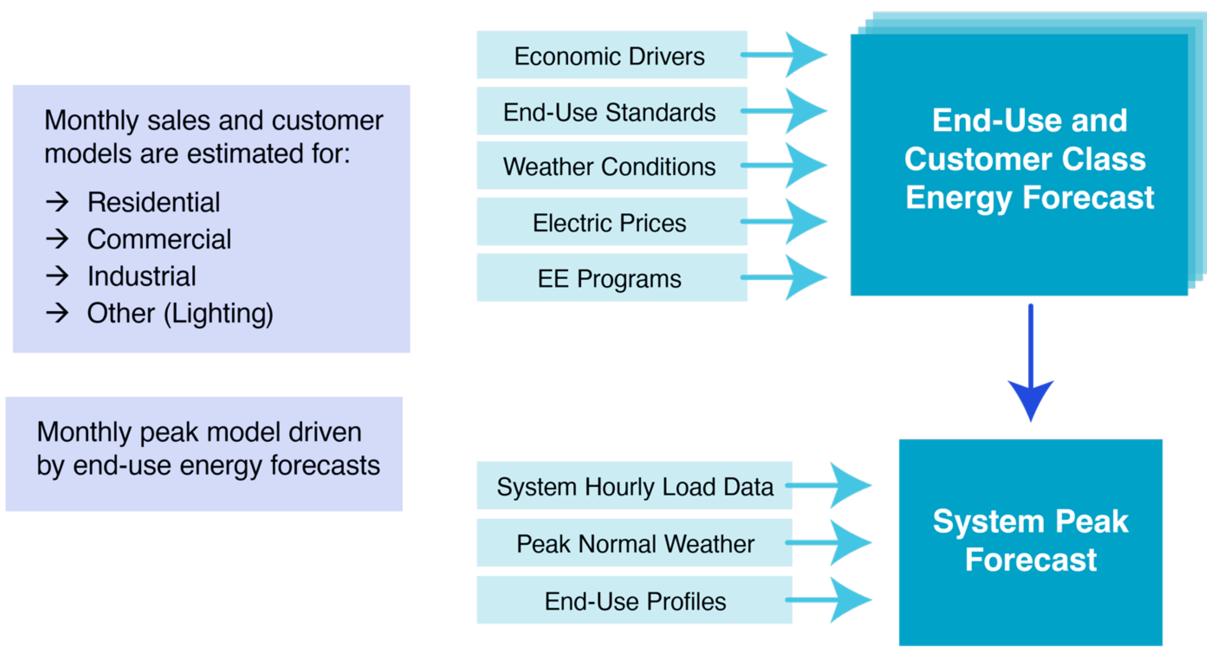
5.3 Forecast Methodology

170 IAC 4-7-4(1), 170 IAC 4-7-4(3), 170 IAC 4-7-4(28), 170 IAC 4-7-5(a)(4), 170 IAC 4-7-5(a)(7), 170 IAC 4-7-5(a)(8), 170 IAC 4-7-5(b), 170 IAC 4-7-5(c), and 170 IAC 4-7-6(a)(6)

The load forecast in AES Indiana's 2025 IRP was developed by Itron using their Statistically Adjusted End-Use ("SAE") load forecasting methodology. Historically, Gross Domestic Product ("GDP") and other economic indicators exhibited a strong correlation with electricity sales. As such, load forecasts were heavily reliant on GDP and economic forecasts. However, this linkage has been less pronounced since 2008. Sales flattened due to efficiency improvements driven by codes, standards, government-sponsored programs, and utility-sponsored DSM. However, over that same period, GDP continued to grow. Itron's SAE methodology addresses this issue by incorporating end-use saturations and efficiency trends from EIA data.

Figure 5-3 provides an overview of the workflow of Itron's SAE model that builds up to a system energy and peak forecast. The dependent variables are being predicted using estimates of cooling requirements ("XCool"), heating requirements ("XHeat"), and other uses ("XOther"). These three variables are constructed using the weather, economic, utility price, and end-use inputs. Thus, all structural and equipment changes, predicted economic impacts, price elasticities, and weather assumptions are captured in the resulting forecast.

Figure 5-3: Iton's SAE Modeling Framework



AES Indiana forecasts monthly sales and customers for each rate code using the method described above. Each customer class is modeled slightly differently owing to the unique characteristics of the classes. In the residential customer class, models are developed for average use and the number of customers; total sales are then the product of the two model outputs. Commercial sales are directly modeled using the SAE approach described above. Industrial sales are directly modeled using an econometric approach, given the lack of saturation and efficiency data provided by the EIA for the industrial sector. The rate code level forecasts are aggregated into a system-level forecast in which line losses are added based on historic loss factors. This system-level forecast, along with the system's hourly load history, peak-day weather, and end-use intensity data, drives the peak forecast. Please see Itron's 2025 Load Forecast Report, which is attached to this Report at Attachment 5-2, for more details on the forecast methodology and results.

The data source descriptions for model variables are as follows:

→ *Economic Drivers* – Economic inputs are Moody's Analytics projections from Q3 2024. See Confidential Attachment 5-5a. The high and low forecasts use a combination of different Moody's Q3 2024 economic scenarios and forecast model standard deviations, see Confidential Attachments 5-5b-c. The high and low load forecasting approach will be described later in this section.

→ *End-Use Standards* – Energy intensities are derived from the EIA's 2023 Annual Energy Outlook ("AEO") for the East North Central Census Division. The EIA End Use Data is available in Confidential Attachment 5-3a-f. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. The EIA does not provide saturation and efficiency trends for the industrial sector.

→ *Weather Conditions* – Historical and normal monthly heating degree days ("HDD") and cooling degree days ("CDD") are derived from National Oceanic and Atmospheric Administration ("NOAA") daily temperature data for the Indianapolis Airport. For residential classes, a temperature base of 60 degrees is used in calculating HDD, and a temperature base of 65 degrees is used in calculating CDD. For commercial classes, a temperature base of 55 degrees is used in calculating HDD, and a temperature base of 60 degrees is used in calculating CDD. Adjusting the base temperature for calculating the HDDs and CDDs for the commercial sector in AES Indiana's 2025 IRP generally improved key forecast model statistics (R-squared and Mean Absolute Percent Error). The improvement in the statistics indicates that this base temperature adjustment better captures the heating and cooling breakpoints for the commercial sector. Generally, industrial classes are not considered weather sensitive and only receive a small, if any, weather adjustment. The base temperature selection is determined by evaluating the sales/weather relationship and determining the temperature at which heating and cooling loads begin

→ *Electric Prices* – Historical prices are derived from billed sales and revenue data. Prices are calculated as a 12-month moving average of the average rate (revenues divided by sales, including trackers); prices are expressed in nominal dollars.

→ *Electric vehicle (EV) and photovoltaic (PV) forecast* – Carnegie Mellon University worked with AES Indiana to develop a machine learning tool that predicts the growth of EV and PV for the next 20 years in the AES Indiana territory. See Attachment 5-4. The method leverages a spatio-temporal point process model that captures the spatial and temporal dependencies in the growth of EV and PV. The forecasts not only estimate where and when these installations will occur but also provide a measure of uncertainty, which becomes the high and low cases in the forecast scenarios. EV and PV assumptions are embedded within the load forecast.

- *Historical class sales and customers* – AES Indiana tracks historical sales and customer data for each discrete rate code, which serves as an input into the load forecasting models.
- *DSM programs* – In Itron's model, the residential and commercial models include trued-up DSM program savings that persist into the study period. However, the 2025 IRP wanted to include DSM as a selectable resource. To allow future DSM as a selectable resource, future DSM savings had to be removed from the load forecast. AES Indiana grossed-up the load forecast, negating future DSM programs. AES Indiana made this adjustment in spreadsheets outside the model.

Capturing Increasing Temperatures

Since 1960, average annual temperatures have been increasing by 0.05 degrees per year, or 0.5 degrees per decade. The average annual temperature in 2023 is six percent higher than in 1960. Average minimum temperatures are increasing at an even faster rate of 1.2 degrees per decade. These results are similar to those found in the Purdue University study for the Indiana Climate Change Impact Assessment.[12] For the baseline forecast, AES Indiana has assumed that temperatures will continue to increase at the historical trend rates.

Low, Base, and High Forecasts

In addition to the base forecast, AES Indiana developed a high and low load forecast. The forecasts were developed using the growth rates Moody's "Alternative Scenario 1 – Upside – 10th Percentile" and "Alternative Scenario 3 – Downside – 90th Percentile." Each alternative scenario represents the case in which the economy has an estimated 10% chance of potentially performing at a higher (or lower, in the downside case) level. See Confidential Attachments 5-5a-c for the Moody's data. The economic scenarios are constructed by applying the scenario economic growth rates to the baseline economic variables starting in the first month of the forecast period (2025). Scenarios are further adjusted to ensure the growth rates are less than or equal to the baseline growth rates in the lower case and greater than or equal to the baseline growth rates in the high case. Please see Attachments 5-7 for AES Indiana's 20-year base, high, and low forecast. The different economic scenarios are used to explore the model's sensitivity to the economic inputs as well as capture risk and uncertainty associated with different economic environments. However, the economic input produced only modest changes in the results across most scenarios. Through the modeling results, AES Indiana found that the uncertainty in the future state of the EV and DG markets was the greatest source of risk in the models. The adoption of

[12] https://ag.purdue.edu/indianaclimate/indiana-climate-report/.

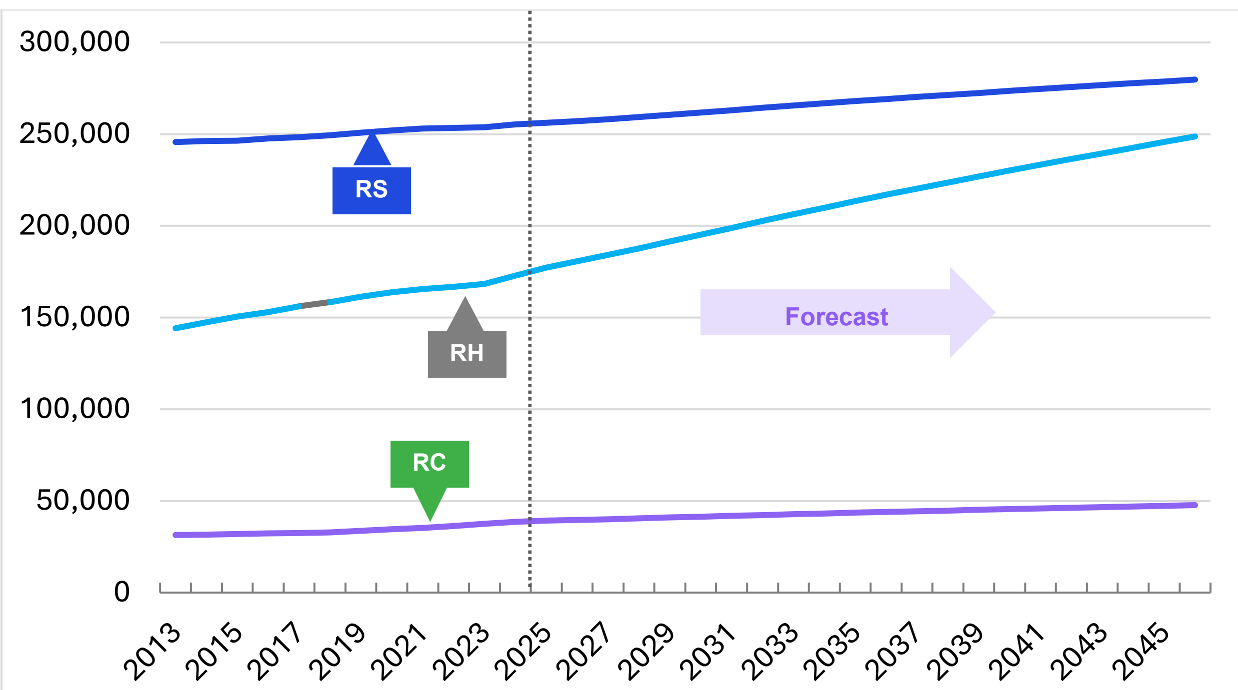
EV and DG is still in its early stages, with tremendous potential to impact load growth in the coming years.

5.3.1 Residential Sector

The residential sector makes up 40% of AES Indiana's total sales. The residential sector is comprised of three primary customer types: natural gas heat, electric heat, and natural gas heat with electric water heat. On a percentage of customer basis, the residential customer types are disaggregated as follows: 55% natural gas heat, 37% electric heat, and 8% natural gas heat with electric water heat. While on a percentage of sales basis, the residential customer types are disaggregated as follows: 46% natural gas heat, 45% electric heat, and 9% natural gas heat with electric water heat.

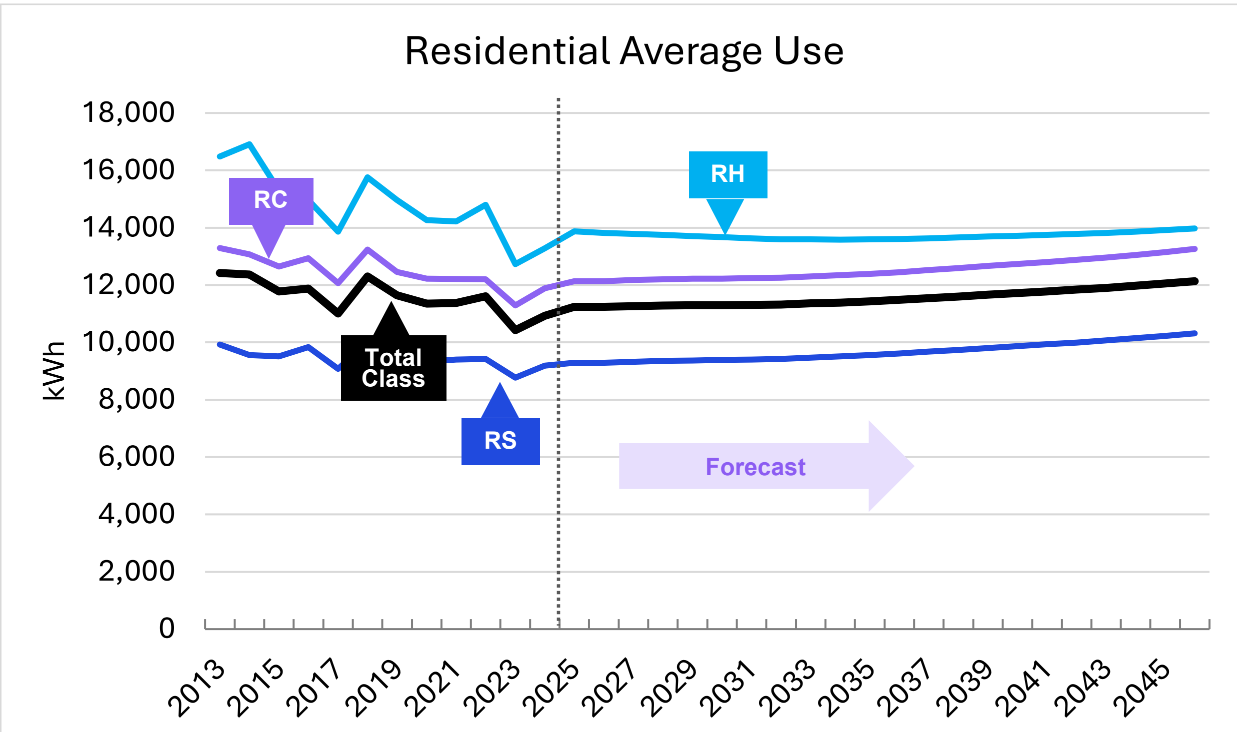
Residential customers are forecasted using a composite economic variable which is comprised of Marion County and Indianapolis metropolitan statistical area household projections. Although the majority of AES Indiana's service territory lies within Marion County, residential customers are more highly correlated with Indianapolis households than Marion County households. For this reason, a composite customer variable was constructed which places a 75% weight on Indianapolis households and 25% weight on Marion County households. While all residential customer classes are forecasted to increase, the RH and RC classes are increasing at a significantly faster rate than the RS class. RH customers are forecasted to increase 1.6% annually, RC customers 0.9% and RS customers 0.4%. Figure 5-4 shows the residential customers forecast.

Figure 5-4: Residential Customer Counts



Residential average use has been declining since 2013. However, average use flattens out and even begins to increase over the forecast period. This forecasted increase is caused largely by two factors: economic growth countering improving end-use efficiency, and future DSM program savings being excluded in the forecast period. Total rate class average use increases partly due to the increasing share of customers with electric heat. Figure 5-5 below shows the historical and forecasted average use, excluding future DSM.

Figure 5-5: Residential Average[13]



The residential sales forecast is generated as the product of the average use and customer forecasts. Total residential sales are calculated by totaling the rate level forecasts. Figure 5-6 below shows the forecasted residential customer sales and average use before future DSM, distributed generation, and electric vehicle adjustments.

[13] Does not include future DSM. Future DSM is modeled as selectable resources in the IRP model.

Figure 5-6: Forecasted Residential Customer Sales and Average Use[14]

Year	Sales (MWh)	Annual Percent Increase (%)	Customers	Annual Percent Increase (%)	Average Use (kWh)	Annual Percent Increase (%)
2025	5,311,304		425,237		12,490	
2026	5,366,192	1.0%	429,001	2026	5,366,192	1.0%
2027	5,432,370	1.2%	432,885	2027	5,432,370	1.2%
2028	5,499,770	1.2%	437,015	2028	5,499,770	1.2%
2029	5,565,805	1.2%	440,588	2029	5,565,805	1.2%
2030	5,630,158	1.2%	445,759	2030	5,630,158	1.2%
2031	5,696,609	1.2%	450,367	2031	5,696,609	1.2%
2032	5,765,185	1.2%	453,801	2032	5,765,185	1.2%
2033	5,844,860	1.4%	456,395	2033	5,844,860	1.4%
2034	5,919,268	1.3%	459,577	2034	5,919,268	1.3%
2035	6,000,610	1.4%	466,733	2035	6,000,610	1.4%
2036	6,086,967	1.4%	472,476	2036	6,086,967	1.4%
2037	6,174,901	1.4%	477,305	2037	6,174,901	1.4%
2038	6,262,362	1.4%	482,278	2038	6,262,362	1.4%
2039	6,350,503	1.4%	487,500	2039	6,350,503	1.4%
2040	6,435,900	1.3%	492,874	2040	6,435,900	1.3%
2041	6,522,227	1.3%	498,345	2041	6,522,227	1.3%
2042	6,610,395	1.4%	503,809	2042	6,610,395	1.4%
2043	6,700,334	1.4%	509,242	2043	6,700,334	1.4%
2044	6,794,592	1.4%	514,590	2044	6,794,592	1.4%
2045	6,891,753	1.4%	519,705	2045	6,891,753	1.4%
2025-45		**1.3%**		2025-45		**1.3%**

5.3.2 Commercial Sector

Commercial sales are also estimated using an SAE model structure; the difference is that the commercial sector sales forecast is based on a total sales model rather than an average use and customer model. The constructed model variables include HDD, CDD, billing days, commercial economic activity variable, price, end-use intensity trends, and historical DSM savings. All but miscellaneous end-use intensities are trending down as the end-use efficiency continues to improve, as can be seen in Figure 5-7. Figure 5-7 shows the commercial end-use intensities that are forecasted through the IRP forecasting horizon from 2025 to 2046.

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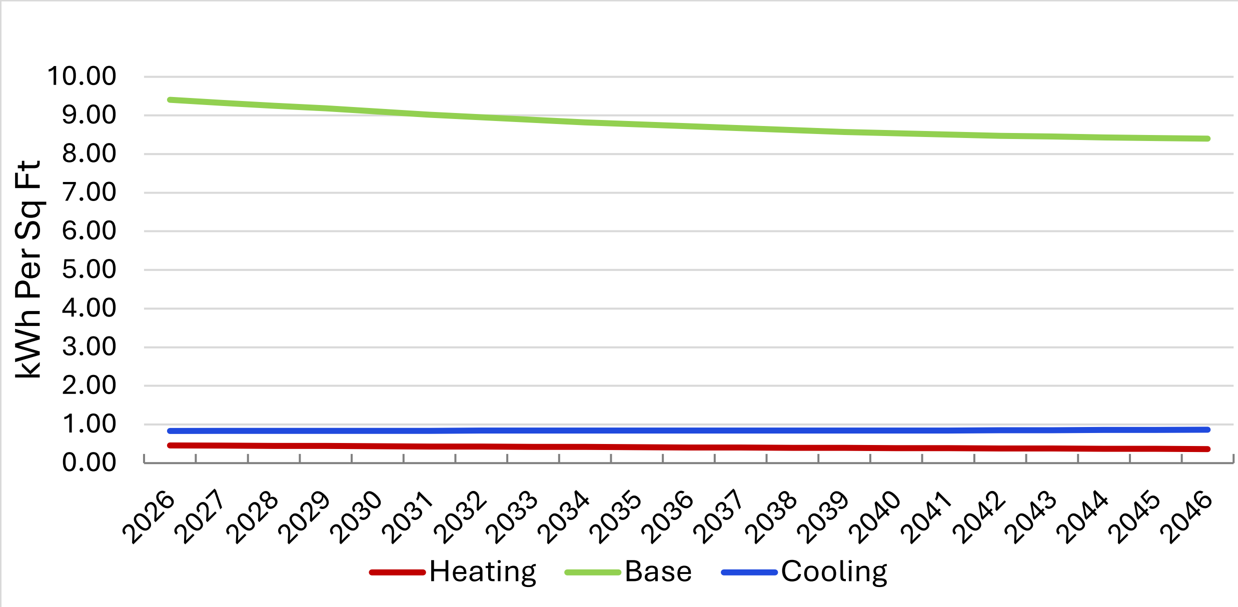
[14] The forecasted sales and average use values do not include future DSM, distributed generation (PV), or electric vehicle adjustments.

Figure 5-7: Aggregated Commercial End-Use Intensity



Commercial sales, like residential sales, have been trending down. Since 2013, annual commercial sales have declined on average by 0.4% per year. The COVID-19 pandemic had a significant impact on commercial electric sales, with sales declining by over 7% in 2020. Sales continue to recover in 2021 but have not fully returned to pre-COVID levels. Excluding 2020 and 2021, commercial sales have declined on average by 0.4% annually from 2011-2019. Aside from negative shock from COVID, the primary factors driving commercial sales are expected economic activity, declining end-use intensities, electric prices, and historical DSM program savings. Over the next twenty years, employment and output average 0.4% and 1.9% annual growth, and total end-use intensity declines 0.5% per year. The combination of these factors results in 0.3% annual commercial sales growth through 2045 before DSM savings adjustments. Figure 5-8 shows the commercial sales forecast, which excludes the impact of future DSM program activity.

Figure 5-8: Commercial Sales Forecast

Year	Commercial (MWh)	Annual Percent Increase (%)
2025	1,850,420	
2026	1,858,783	0.5%
2027	1,861,686	0.2%
2028	1,865,911	0.2%
2029	1,870,946	0.3%
2030	1,872,035	0.1%
2031	1,873,667	0.1%
2032	1,876,522	0.2%
2033	1,880,591	0.2%
2034	1,885,060	0.2%
2035	1,890,455	0.3%
2036	1,897,035	0.3%
2037	1,901,765	0.2%
2038	1,906,375	0.2%
2039	1,910,711	0.2%
2040	1,916,807	0.3%
2041	1,924,141	0.4%
2042	1,932,222	0.4%
2043	1,941,182	0.5%
2044	1,950,137	0.5%
2045	1,959,208	0.5%
2025-45		**0.3%**

5.3.3 Industrial Sector

The industrial sector is forecasted using a more traditional econometric modeling approach – please see page 16 of Itron's 2025 Load Forecast report in Attachment 5-2 for more information regarding the industrial load forecasting methodology.

The high load factor and primary service rate classes are mostly for industrial customers. These classes have relatively few customers, ranging between 3 and 30 customers per class. Sales in these classes are often not highly correlated with economic drivers and have large fluctuations in sales from month to month. The models do not include economic drivers; the resulting forecast is flat, only reflecting seasonal and monthly usage patterns. The industrial models include a CDD variable to account for weather response in the summer months, but do not include an HDD variable, are their sales do not increase or decrease with changes in winter temperatures. The models are estimated over a shorter time period, beginning in 2018.

Figure 5-9 shows the industrial sales forecast, which excludes the impact of future DSM program activity. In order to capture the load that will be coming on the AES Indiana system that is not represented in the historical data, the load forecasting team meets with the AES Indiana Strategic Accounts team to assess new customer load. A hypothetical example of a new customer load may be that an existing customer is adding a new 10 MW facility on January 1, 2026. Using the customer input on the type of facility, AES Indiana estimates a load factor for the addition (for example, 80%) to calculate annual MWh consumption (in this hypothetical case, 10*0.8*8760 = 70,080 MWh annually). AES Indiana then divided this estimate by 12 months and added it to the load forecast starting January 1, 2026. This load remains on the system unless the customer indicates that it is only temporary or shutting down.

Figure 5-9: Industrial Sales Forecast

Year	Industrial (MWh)	Change
2025	6,020,015	
2026	6,059,504	0.7%
2027	6,140,103	1.3%
2028	6,152,803	0.2%
2029	6,166,796	0.2%
2030	6,172,540	0.1%
2031	6,179,214	0.1%
2032	6,188,794	0.2%
2033	6,201,081	0.2%
2034	6,214,465	0.2%
2035	6,229,696	0.2%
2036	6,247,511	0.3%
2037	6,261,714	0.2%
2038	6,275,733	0.2%
2039	6,289,031	0.2%
2040	6,306,513	0.3%
2041	6,326,497	0.3%
2042	6,347,892	0.3%
2043	6,371,140	0.4%
2044	6,394,370	0.4%
2045	6,417,920	0.4%
2025-45		**0.3%**

New large load requests for data center load are not embedded in the forecast; these are handled by modeling different loads within the portfolios and scenarios.

5.3.4 Streetlighting

The Commission's December 13, 2017, Order in Cause No. 44981 approved a Public Lighting Agreement between AES Indiana and the City of Indianapolis, which provided a three-year Light-Emitting Diode ("LED") conversion project and the installation of additional LED street lighting in the city. The conversion work commenced following the awarding of contracts in the spring of

2018 and concluded in November 2021. Throughout the life of the program, the number of LED conversions is 26,000 or approximately 60% of all fixtures. The forecast model for street lighting is a trended time series model. Since the conversion and additions were included in the model's input data, street lighting was reflected in the forecasted load.

5.4 Load Model Performance and Analysis

170 IAC 4-7-4(2) and 170 IAC 4-7-5(a)(10)

AES Indiana periodically evaluates the load forecast model performance: (1) when the model is created, (2) on a monthly basis as a variance analysis, and (3) after-the-fact as a year-end comparison.

During forecast development, a number of models are analyzed at the rate level. The adjusted R-squared statistics, Mean Absolute Percent Error ("MAPE"), the Durbin-Watson statistics, and the reasonableness of each model to AES Indiana are statistically evaluated. The target adjusted R-squared values are better than 90%, which is accomplished in nearly all cases. Further, MAPE is targeted at less than 2%, and the Durbin-Watson statistics are targeted at around 2.0. AES Indiana considers independent variables with T-statistics of at least 2.0 acceptable. This judgment is somewhat subjective and dependent upon the implied importance of the variable. Please see Attachment 5-2, Itron's Load Forecast report, for more information regarding these model statistics.

At the start of the COVID-19 pandemic, AES Indiana began seeing large deviations from its projected energy sales. At the start of the COVID-19 pandemic, AES Indiana started to update its load forecast on a rolling monthly basis. During these monthly updates, customer data is rolled forward to include the most recent data, along with expected weather, load, and shift variables related to COVID. Additionally, AES Indiana continues to evaluate the variance of energy sales each month and considers the impact of weather adjustments. AES Indiana's forecasting staff uses this information to evaluate model performance. If the monthly variance moves reasonably with the current "knowns," like economic factors and/or weather, a conditional approval supports the forecast. However, should variance move contrary to "knowns," an investigation of possible bias and other elements is undertaken. A similar determination, but with greater detail, is made at year-end.

5.5 Electric Vehicles and Distributed Solar

170 IAC 4-7-4(18)

With the ongoing advancements in EV and PV technologies and related program implementations, the penetration rates of these resources continue to grow within the Indiana region. AES Indiana recognizes the importance of monitoring long-term EV and PV adoption scenarios to effectively anticipate future demand and to provide cost-effective solutions and customer benefits.

AES Indiana hired Shixiang (Woody) Zhu and his team from Carnegie Mellon University to create the EV and distributed PV forecasts that were embedded into the load forecast.

5.5.1 EVs in AES Indiana's Territory

Building on the foundational work of the 2022 IRP to advance a resilient smart grid capable of accommodating the increasing energy demand from EV charging, AES Indiana has initiated several pilot programs to explore innovative integration of distribution-level resources into the resource plan. These initiatives include a range of C&I public use programs that evaluate the electrification plans and their impact on commercial customers' load growth, as well as test peak-shaving and interconnection offset opportunities by leveraging smart EV charging devices to manage peak impact.

Additionally, drawing on insights from early residential rate-based pilots and emerging smart charging technologies, AES Indiana has phased out the time-of-use (TOU) rate EVX that required customers to install a secondary meter, in favor of a more accessible incentive-based program that only requires a compatible smart device to participate. By leveraging Wi-Fi-enabled electric vehicles and chargers, these expanded programs test multiple methods for incentivizing customers to shift EV charging to off-peak hours to better inform demand response strategies as EV adoption rates continue to climb.

5.5.2 Literature Review and Prototypical Electric Vehicle

According to the 2024 U.S. Transportation Statistics Annual Report[15], EV sales in the U.S. increased from approximately 500,000 in 2012 to 1.5 million in 2021 and further to 2.5 million in 2023, demonstrating an exponential adoption trend. The majority of this growth is attributed to light- and medium-duty vehicles, while heavy-duty EVs currently occupy a relatively small market share. These developments underscore the need for utility planners and policymakers to prioritize EV adoption in resource planning efforts, with particular emphasis on modeling the adoption of light- and medium-duty vehicle segments.

A range of methodologies has been developed for scenario modeling of distributed energy resources (DERs), including EVs and PV systems. Adoption modeling approaches span econometric models, time series models, and bass diffusion models, which are adept at leveraging macro-level indicators—such as socioeconomic and weather data—to project aggregate adoption trends. Alternatively, agent-based modeling (ABM) offers a complementary framework that utilizes micro-level indicators to simulate customer-level decision-making and market dynamics, thereby providing a more granular perspective on DER adoption behaviors.

5.5.3 Forecasting Methodology

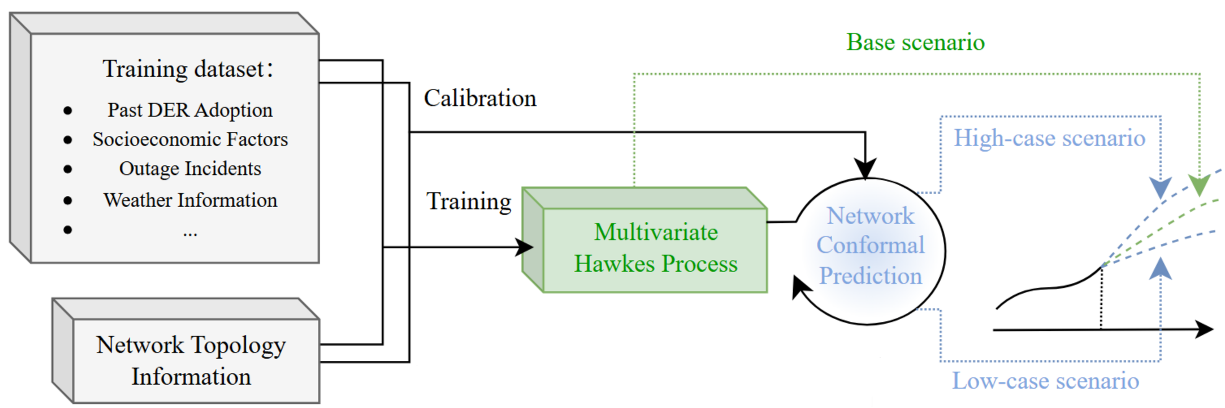
The forecasting methodology developed for this study aims to generate base, low, and high load scenarios for EV and PV adoption trajectories (measured in number of premises) from 2025 to 2050. The base scenario reflects a business-as-usual trajectory, assuming current trends and policy conditions remain relatively stable. The low scenario models a more conservative pathway, incorporating assumptions of slower technological advancement, reduced policy support, and lower customer engagement. Conversely, the high scenario reflects an accelerated adoption

[15] https://rosap.ntl.bts.gov/view/dot/79039

trajectory, supported by favorable policy measures, declining technology costs, and heightened public participation in EV and PV programs.

To support this effort, a general framework has been established for modeling EV and PV adoption across residential and commercial sectors. Specifically, the base forecast utilizes a probabilistic model known as the multivariate Hawkes process, which is calibrated from historical adoption data using a bottom-up approach. The low and high scenarios are derived from the base forecast through a statistical technique called conformal prediction, which quantifies forecast uncertainty and bounds alternative adoption trajectories.

Figure 5-10: Scenario Modeling Framework



The same modeling framework is applied across both EV and PV technologies and across residential and commercial sectors, with variations in key hyperparameters tailored to each segment. Figure 5-10 above shows a graphical overview of the modeling framework provided in the following section to illustrate the methodological process.

Base Load EV and PV Forecast Modeling

The base case forecast for EV and PV adoption was developed using a probabilistic modeling framework based on the multivariate Hawkes process. This statistical approach enables the modeling of continuous-time adoption events at the customer level and captures key behavioral dynamics observed in the distributed energy resources (DER) adoption lifecycle. The model was applied at the distribution level, with results aggregated via a bottom-up process to estimate system-wide adoption trajectories.

Key components and assumptions of the model are detailed below.

Social Diffusion Effect

The model explicitly accounts for peer effects in EV and PV adoption, a phenomenon well-documented in both academic literature and market data. Social diffusion describes how the likelihood of an individual adopting EVs or rooftop PV systems increases when others in their social or geographic proximity have already adopted these technologies. The multivariate Hawkes framework incorporates this interdependence through a calibrated parameter that governs the intensity of peer influence. This parameter was estimated using maximum likelihood techniques applied to historical installation data.

The social diffusion effect has been shown to be a significant factor in accelerating DER adoption, particularly in residential neighborhoods. It serves as a micro-level mechanism that can give rise to the S-shaped adoption curve commonly captured by Bass diffusion models. Incorporating this dynamic enables the model to better reflect the real-world momentum of adoption trends.

Saturation Effect

The model includes a representation of saturation dynamics, which captures the diminishing rate of new adoptions once a region reaches a critical mass of DER penetration. This effect is modeled through a learnable parameter that attenuates adoption intensity based on the existing penetration level. The saturation effect of DER adoption is well-documented in marketing science studies.[16] The inclusion of saturation behavior supports more realistic long-term forecasts by accounting for the finite nature of the potential adopter pool and the declining marginal influence of early adopters over time.

In the base scenario, the saturation effect—which governs the deceleration of adoption as market potential is approached—is modeled as a piecewise linear function of the theoretical penetration rate and a tipping point. This formulation reflects a stylized but empirically supported representation of technology diffusion in utility and consumer markets.

- *Theoretical Penetration Rate:* Defined as the estimated maximum proportion of customers within a given service area who are likely to adopt the technology under consideration (e.g., EVs or PV systems). This value serves as the upper bound for adoption in the long term.
- *Tipping Point:* Defined as the point in time when the adoption curve experiences its steepest slope, i.e., the inflection points of acceleration. Based on prior research in the energy technology diffusion literature, the tipping point often coincides with a 5% market penetration threshold. This empirical benchmark is widely cited and used to calibrate early-to mid-stage diffusion trajectories.

In this study, these two conceptual definitions of the tipping point—temporal acceleration and 5% penetration threshold—are treated as functionally equivalent, consistent with established findings in market adoption studies. Figure 5-11 below provides a summary of the adopted parameter values, sources, and rationale used to define the saturation effect in the modeling framework. These values ensure internal consistency and traceability to recognized industry and academic standards.

Figure 5-11: Assumption for saturation rate parameter specification

	EV	PV
Theoretical Penetration Rate	56.25% (Total)	7% (Residential) and 4% (Commercial)
Tipping Point	2029	2032

16 https://resources.environment.yale.edu/gillingham/BollingerGillingham_PeerEffectsSolar.pdf

The data in Figure 5-11 is described below.

Theoretical Penetration Rate

EVs

The assumed long-term EV penetration rate for the region is 56.25%. This estimate reflects the expected share of customers who will adopt EVs over the forecast horizon and is consistent with a range of recent consumer surveys and global market projections:

→A national survey indicated that 54% of internal combustion engine (ICE) vehicle drivers would consider purchasing an EV within the next 3–5 years.[17]

→A global survey found that 57% of respondents expect to own an EV within the next decade.[18]

→In the U.S., 38% of respondents reported that they would seriously consider buying an EV, with an additional 40% expressing openness to the idea.[19]

PV

The model assumes a maximum PV penetration rate of 7% for the residential sector and 4% for the commercial sector. These values are informed by historical model fitting and comparative benchmarks.

→The residential value is approximately 1.5× the current PV penetration level observed in California, indicating a conservative but forward-looking forecast for Indiana. The current penetration of California is around 4.5% (1.8 million solar installations divided by 40 million population, both 2024 estimates[20]). The scaling factor 1.5 is derived by analogy from the electricity sales ratio, where Indiana's technical potential for solar is 29.5% of statewide electricity sales[21], and the 2023 California in-state generation from solar is 19.17%[22], yielding 29.5% ÷ 19.17% ≈1.54.

→Only a limited saturation trend in the commercial sector has been observed, indicating the potential for continued growth beyond the modeled horizon. This is supported by a Stanford-led study finding that non-residential rooftops have large unused capacity, which

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[17]https://www.coxautoinc.com/news/cox-automotive-2024-path-to-ev-adoption-study-suggests-electric-vehicle-consideration-will-surge-in-second-half-of-decade/
[18]https://www.computerweekly.com/news/366615502/Electric-vehicle-tipping-point-for-US-drivers-expected-in-next-10-years
[19]https://advocacy.consumerreports.org/wp-content/uploads/2024/02/CR_2023EV-Survey_Facthseet_Final.pdf
[20]https://www.californiadgstats.ca.gov/charts/
[21]https://docs.nrel.gov/docs/fy16osti/65298.pdf
[22]https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2023-total-system-electric-generation

could be utilized to meet >20% of annual residential demand in ⅔ of disadvantaged communities.[23]

Tipping Point

EVs

The EV tipping point is assumed to occur in January 2029. This selection is supported by multiple sources, including a market potential analysis conducted by Camus Energy[24] in partnership with AES Indiana, which identified early 2029 as the expected point of rapid acceleration in EV adoption for the Indianapolis region. Additionally, global market data suggest that the EV tipping point was reached around late 2021 internationally, with U.S. adoption following a similar trajectory within the current decade.[25]

PVs

The tipping point for PV adoption is defined at a 7.56% penetration level, based on market dynamics and policy outlooks. Supporting evidence includes:

→The Shining Cities 2022 solar energy survey, which ranks Indianapolis 12th nationally in total solar capacity, identifying it as a "solar superstar" city.[26]

→The SEIA Solar Market Insight Report (2024) projects continued growth in U.S. residential and commercial solar installations through at least 2029.[27]

→Federal and state policy drivers are expected to sustain adoption momentum, including the Clean Electricity Investment Tax Credit (CEITC)[28], in effect through 2032, and Indiana Senate Enrolled Act 309, which provides incentives for systems installed through 2047.[29]

Macro-Level Drivers and Exogenous Covariates:

In addition to peer and saturation effects, the model integrates a set of macroeconomic and infrastructure-related covariates known to influence DER adoption patterns. These variables are included in the model as linear predictors that affect the base intensity of adoption. Key inputs include the following:

- *Household Median Income (2022 dollars):* Household median income was derived from U.S. Census Bureau datasets, with spatial granularity at the census tract level. Income levels are positively correlated with both EV and PV adoption, consistent with prior empirical studies.
- *Feeder-Level Load Characteristics:* Total power line load was calculated using time-averaged three-phase current data across feeders. Load values were converted to

[23] https://news.stanford.edu/stories/2024/04/stanford-led-research-shows-how-commercial-rooftop-solar-power-could-bring-affordable
[24] https://www.aes.com/ev-tipping-point
[25] https://cleantechnica.com/2024/03/28/the-ev-revolution-has-passed-a-tipping-point/
[26] https://frontiergroup.org/resources/shining-cities-2022/
[27] https://seia.org/research-resources/solar-market-insight-report-q3-2024/
[28] https://www.irs.gov/credits-deductions/clean-electricity-investment-credit
[29] https://legiscan.com/IN/text/SB0309/id/1590334

kilovolt-amperes (kVA) using system voltage and standard conversion factors. These values serve as a proxy for existing infrastructure utilization and localized demand, informing technical feasibility and attractiveness of DER adoption in specific areas. The unit is kilovolt-ampere, and the data spans from the beginning of 2021 to the end of 2023.

- *System Average Interruption Duration Index (SAIDI):* This metric represents the average duration of customer power interruptions and is calculated at the circuit level. SAIDI serves as a proxy for local reliability and infrastructure quality, which can influence customer decisions regarding distributed energy resource adoption, calculated as:

System Average Interruption Duration Index Formula

$$SAIDI = \frac{Total\ minutes\ of\ power\ outages}{Number\ of\ customers}$$

SAIDI is calculated from the exact coordinates and duration of each outage. The temporal coverage extends from the beginning of 2004 to August 2024.

- *Annual Rooftop Solar Generation Potential:* The model also incorporates estimates of the total annual solar energy generation potential across all rooftop areas within the region, measured in kilowatt-hours (kWh). These estimates, sourced from Google Project Sunroof (as of the August 2019 update), are provided at the census tract level. This covariate captures the physical feasibility of PV adoption based on rooftop orientation, shading, and area.

The linear coefficients associated with these covariates were estimated using maximum likelihood methods, enabling the model to quantify their influence on adoption rates while controlling for other factors.

Low and High EV and PV Forecast Modeling

To capture the inherent uncertainty in future EV and PV adoption, low and high load scenarios were developed using a statistically rigorous, data-driven methodology. These scenarios were derived through a calibration procedure known as conformal prediction, applied to the base model trained on adoption data from the 2018 to 2024 period.

Conformal prediction is a statistical technique used to generate valid prediction intervals without requiring strong assumptions about the distribution of the underlying data. In this application, the approach leverages out-of-sample residuals from the base model to construct nonconformity scores, which quantify the deviation of observed adoption events from the model's expectations. By selecting appropriate quantiles of these scores corresponding to the desired confidence level, the method defines the lower and upper bounds of the prediction interval. These bounds are used to define the low and high scenarios, respectively.

A key advantage of the conformal prediction framework is that it removes the need for manual tuning or subjective specification of scenario assumptions, which can introduce bias or inconsistency. Instead, the model uses historical data to derive statistically valid bounds on forecast uncertainty. Additionally, the conformal approach is distribution-free, meaning it does not rely on assumptions about the specific form or behavior of EV or PV adoption trends, making it particularly well-suited for modeling emerging technologies with evolving dynamics.

This methodology enhances the robustness of scenario planning by ensuring that both the low and high adoption projections remain consistent with historical patterns and uncertainty levels observed in the reference dataset. For technical details regarding the implementation of conformal prediction in this context, readers are referred to the accompanying technical documentation.

Units to Energy Conversion Formulas

Adoption forecasts, expressed in terms of the number of customer premises adopting EVs or PV systems, are translated into estimated electricity consumption and generation impacts using sector-specific conversion methodologies. These methodologies are tailored to reflect differences in load behavior and system integration between technologies and customer classes.

EVs

For EV adoption, a top-down estimation approach is applied. The total electricity demand attributable to EVs is first computed at the system level and then disaggregated into residential and commercial sectors. The total EV-related load is calculated using the following formula:

Figure 5-12: EV Energy Conversion Formula

$$\text{MWhs} = \sum_{i=\text{Cars, Light trucks}} \frac{\text{Avg distance driven} \times \text{Energy consumption} \times \text{EV units} \times \text{Ratio of } i}{1000}$$

This formulation accounts for two primary vehicle classes: passenger cars and light trucks. The forecasted number of EV-adopting premises is obtained from the base adoption model, while vehicle mix ratios, annual vehicle miles traveled (VMT), and energy intensities are sourced from national transportation and energy datasets. A summary of these assumptions is provided in Figure 5-13 below. These assumptions ensure consistency with broader electrification planning and reflect current technology benchmarks.

Figure 5-13: EV Transportation and Energy Assumptions

	Low	Base	High
Average distance driven (miles)	4,000 (cars and light trucks)	5,300 (cars and light trucks)	8,000 (cars and light trucks)
Energy consumption (KWh / miles)		0.345 (cars and light trucks)	
Ratio of vehicle type		56.7% (cars) and 43.3% (light trucks)	

Residential and commercial EV electricity loads are disaggregated from the total electricity load above using the following formulas:

$$Residential\ EV\ Energy\ (MWh) = 54.9\%\ x\ Total\ MWh$$

$$Commercial\ EV\ Energy\ (MWh) = 41.5\%\ x\ Total\ MWh$$

The scaling factors of 54.7% for residential and 45.1% for commercial are from the EIA[30], according to the total industry energy consumption ratio by sectors.

PVs

In contrast, PV system generation is modeled using a bottom-up approach, in which residential and commercial sectors are analyzed independently and then aggregated to obtain total generation potential. This approach reflects the sector-specific differences in system sizing, rooftop availability, and typical production profiles.

For each sector, total generation is computed by combining the number of adopted premises with assumptions regarding system size, capacity factor, and solar potential. Assumptions are adjusted for geographic and structural considerations. The resulting energy estimates are then summed across sectors to provide total distributed solar generation for the planning horizon. PV electricity load is computed by the following formula:

$$Residential\ PV\ Energy\ (MWh) = 10.31\ x\ Residential\ Units$$

$$Commercial\ PV\ Energy\ (MWh) = 81.70\ x\ Commercial\ Units$$

10.31 and 81.70 are conversion factors obtained from the AES Indiana 2022 IRP report.[31] The residential and commercial installed PV units are obtained from the base scenario model forecast.

30 https://www.eia.gov/energyexplained/us-energy-facts/
31 https://www.aesindiana.com/sites/default/files/2022-12/AES-Indiana-2022-IRP-Volume-I.pdf

5.5.4 Electric Vehicle and Distributed Solar Forecasting Results

This section summarizes key forecast results for EV adoption and load growth and distributed PV generation, based on the modeling framework described in previous sections. Results are presented for the total, residential, and commercial customer segments where applicable. Although twelve outputs were generated in total, this section focuses on four primary outputs: Total EV load, Residential EV load, Commercial EV load, and Total PV generation. Detailed results, including sector-level PV breakdowns and additional scenario outputs, are available in the accompanying technical documentation.

EV Forecast Results

The forecast for total EV electricity demand (in MWh) indicates substantial potential under the optimistic scenario, with sustained near-linear growth exceeding 50,000 MWh per year. By 2040, EV load is projected to reach approximately 800,000 MWh annually, rising to 1,400,000 MWh by 2050. In contrast, the business-as-usual (base case) and pessimistic scenarios show significantly lower demand, with the base case reaching around 500,000 MWh with an annual growth rate of 25,000 MWh and the low case approaching 200,000 MWh by 2050. Notably, the saturation effect modeled does not appear to limit growth (i.e., no pronounced S-curve is observed), suggesting a high theoretical saturation threshold and substantial untapped market potential for EV adoption in the broader Indianapolis region, with a gap of 900,000 MWhs between the high and base scenario forecast by 2050.

Figure 5-14: Projected Total Sales (MWh) of EVs in AES Indiana's Service Territory

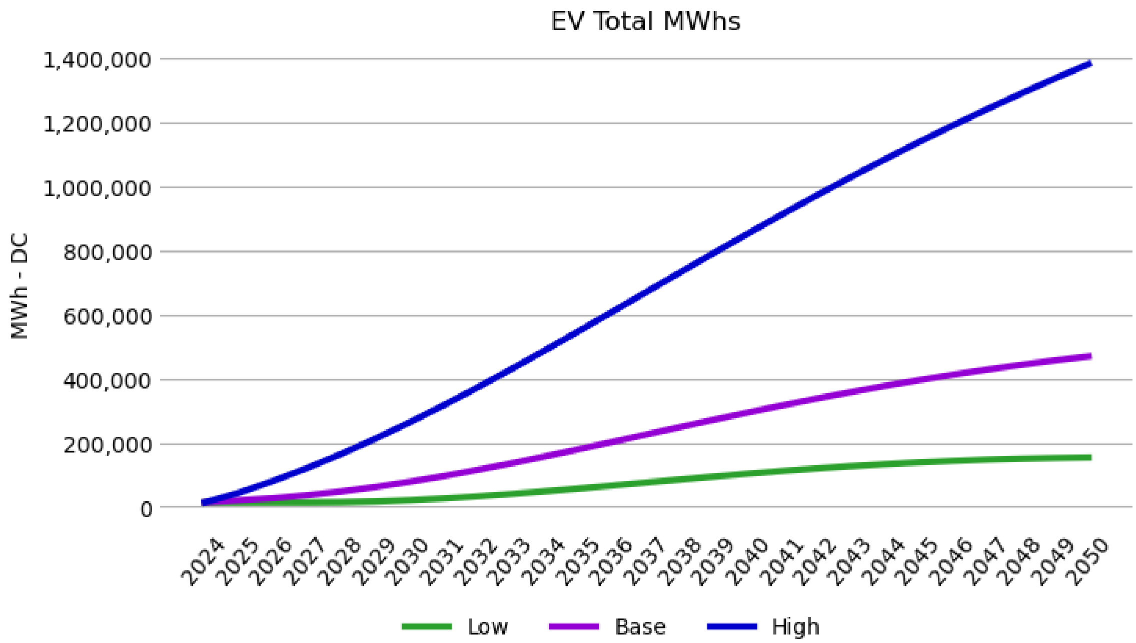


Figure 5-15: Projected Residential Sales (MWh) of EVs in AES Indiana's Service Territory

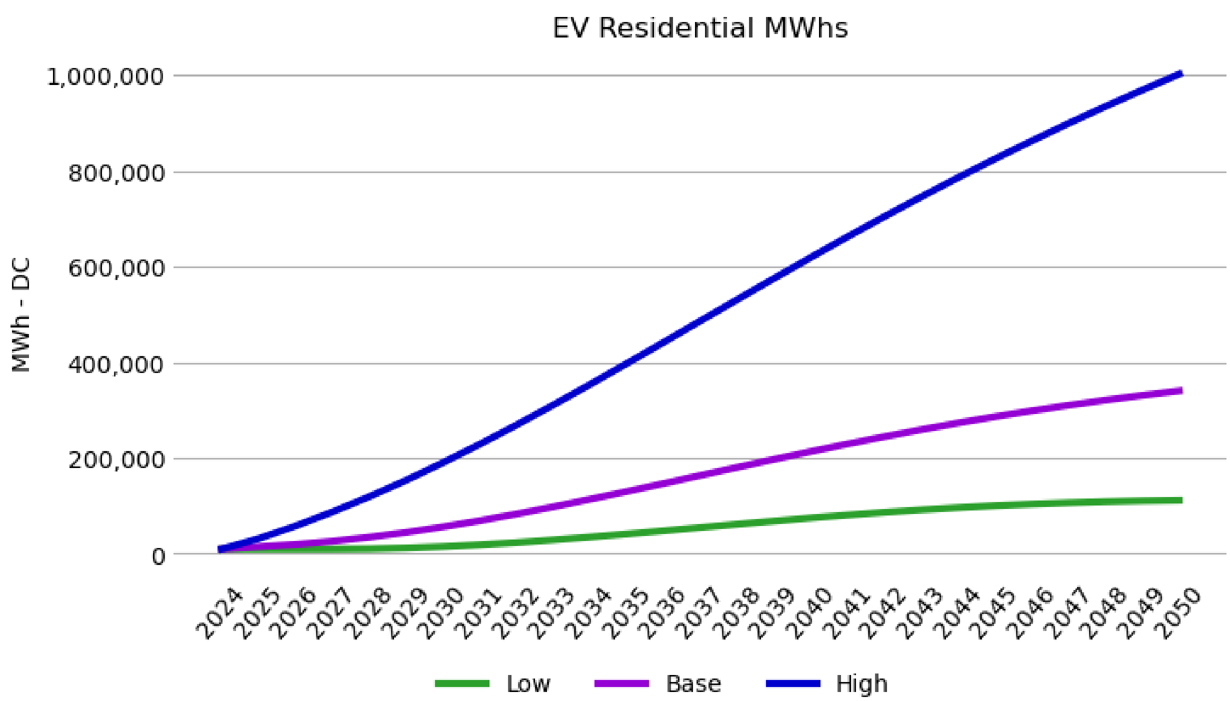
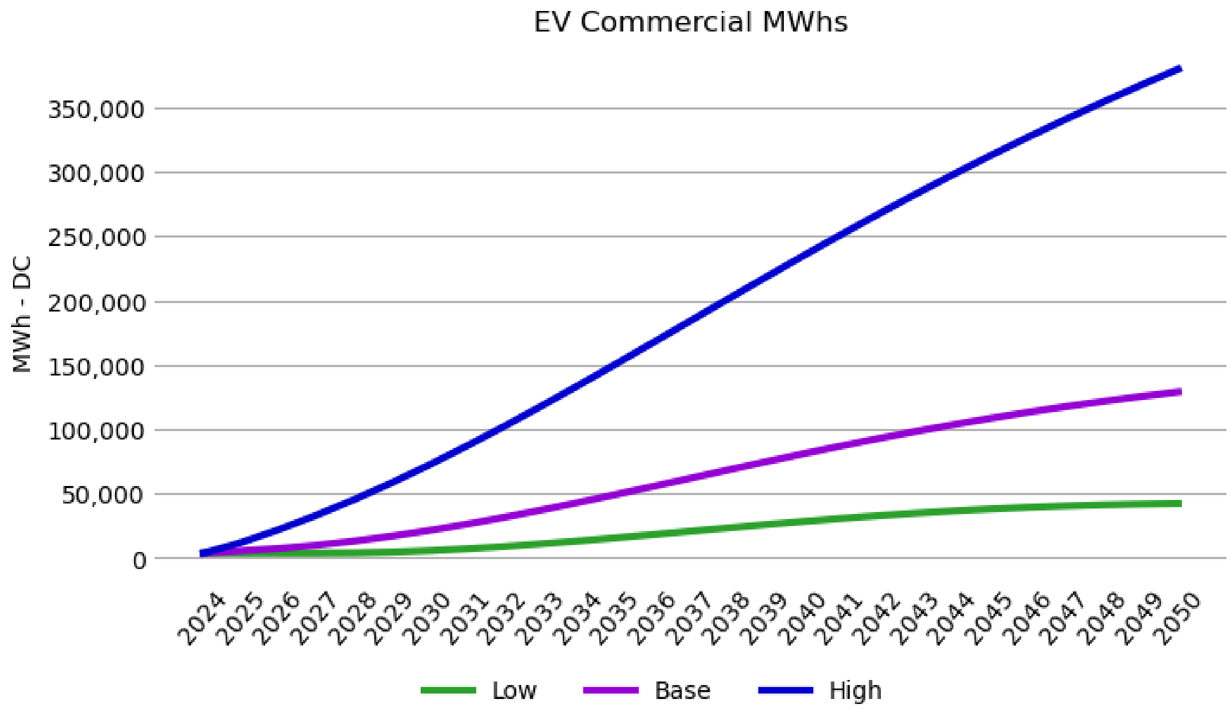


Figure 5-16: Projected Commercial Sales (MWh) of EVs in AES Indiana's Service Territory



Alternatively, examining the sectoral EV load forecast reveals that the residential sector is the dominant contributor, reaching nearly 1,000,000 MWh by 2050. In contrast, the commercial sector contributes less than half of that, with an estimated 400,000 MWh by 2050.

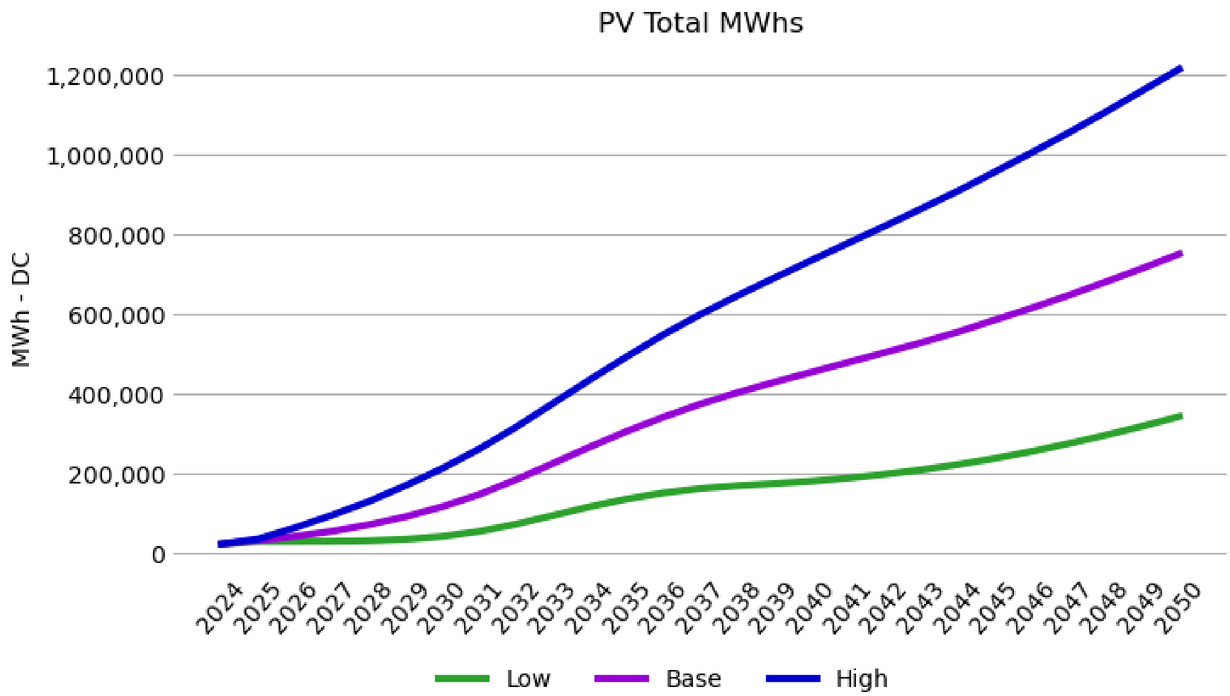
One limitation of this study is its focus on only passenger cars and light trucks, excluding medium- and heavy-duty vehicles. This omission may lead to an underestimation of the commercial sector's load. However, as previously noted, the current number of medium and heavy-duty EVs remains relatively low, so the resulting bias is expected to be minimal, as noted by the 2024 U.S. Transportation Statistics Annual Report.[32]

PV Forecast Results

The PV electricity generation shows a relatively steady trend, with the low and high scenarios symmetrically and tightly distributed around the base scenario forecast. An annual generation of less than 50,000 MWhs is expected, with the base scenario reaching over 400,000 MWhs by 2040 and 800,000 MWhs.

[32] https://rosap.ntl.bts.gov/view/dot/79039

Figure 5-17: Total Solar PV System Energy Production (MWh-DC)



Based on the application of the assumptions noted above, the CMU Team developed three adoption scenarios for solar PV installations are described below:

→ Low; up to 6% market adoption by 2050

→ Medium; up to 15% market adoption by 2050

→ High; up to 29% market adoption by 2050

The forecasts for system and energy (MWh-DC) are shown in Figure 5-17.

5.5.5 Distributed Solar (Non-Net Metered/Rate REP)

The majority of AES Indiana's other distributed energy resources are related to the AES Indiana feed-in-tariff Rate Renewable Energy Production ("Rate REP"). Rate REP was initially offered in 2011 and is fully subscribed and not available to new participants. Under this offering, the total output of the 37 projects is approximately 94 MW.

EV and PV Forecast Assumptions

The EV and PV forecast from Carnegie Mellon were combined with the load forecasts from Itron to make the inputs for the IRP. The resulting combinations for the Scenarios are listed in

Figure 5-18.

Figure 5-18: Load, EV and PV Forecasts By Scenario

	Reference case	Gas infrastructure challenges	High regulatory: environmental	Stable markets scenario
AES Indiana load	Base	Base	↑	↓
EV/distributed solar	↓	Base	↑	Base

5.6 Data Center Load Discussion

In recent years, data centers have emerged as a rapidly growing segment of electric load in power systems across the United States. Characterized by their high energy density, consistent load profiles, and growing operational footprints, data centers are increasingly being viewed as a critical new end-use category—particularly in the context of digital transformation, artificial intelligence, cloud computing, and advanced manufacturing.

Indiana is becoming an attractive destination for data center development. AES Indiana has received inquiries from hyperscale and enterprise customers expressing interest in developing large-scale data center campuses in the region. This trend reflects broader national patterns and introduces a new layer of uncertainty in long-term load forecasting.

Given the magnitude and pace of potential data center deployment, AES Indiana has, for the first time, incorporated dedicated data center load forecasts into its 2025 IRP. Each scenario is optimized for a no, low, mid, and high data center forecast. This allows AES Indiana to differentiate the resource decisions needed for native load growth and new large load customers.

Background and Industry Trends

Data centers are specialized facilities that house computer systems and associated infrastructure, such as networking and storage. These facilities serve as the backbone of the digital economy, supporting applications ranging from e-commerce and online banking to video streaming, scientific computing, and artificial intelligence workloads.

Key characteristics of data center loads include:

- High load factors (often greater than 90%) and relatively flat load profiles.
- Rapid development timelines, especially among hyperscale customers.

- Significant cooling and backup generation infrastructure, sometimes impacting local capacity and interconnection dynamics.

Across the U.S., data center power demand is projected to more than double over the next decade. The continued expansion of cloud computing, the proliferation of AI and machine learning applications, and the increasing electrification of industrial digital infrastructure drive this growth. In regions such as Virginia, Texas, and Ohio, data center loads are already exceeding 1–2 GW in some utility footprints.[33]

While deployment is still in its early stages, AES Indiana has received inquiries from new large load customers. The exact timing, location, and magnitude of future needs remain uncertain and are subject to land use permitting, economic development efforts, customer procurement decisions, and transmission availability, among other factors.

Data Center Load in the 2025 IRP

Incorporating data center load materially affects long-term planning outcomes within an IRP. Data center penetration accelerates the need for new generation or capacity resources.

AES Indiana incorporated data center load in its capacity expansion modeling as four possible blocks of additional load (no, low, mid, and high penetration). The four load scenarios represent bookend trajectories based on customer discussions, national market trends, interconnection data, and industry forecasts.[34] Each scenario was optimized for the four data center loads to create a distinct portfolio of resources. This allowed the impact of incremental data center load on resource selection to be reviewed.

Each scenario provides an estimate of the incremental peak demand associated with data centers, defined as the additional load expected by the end of each calendar year. The scenarios were modeled independently of baseline economic and demographic load drivers.

[33] https://www.cesa.org/wp-content/uploads/Load-Growth.pdf; https://nescoe.com/resource-center/data-centers-primer/.

[34] https://www.energy.gov/articles/doe-releases-new-report-evaluating-increase-electricity-demand-data-centers
https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf
https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf

Figure 5-19: Data Center Scenarios for 2025 IRP

Peak by End of Calendar Year (MW)	No	Low	Mid	High
2027	0	0	50	75
2028	0	50	231	378
2029	0	114	413	681
2030	0	179	594	984
2031	0	243	775	1,288
2032	0	307	956	1,591
2033	0	371	1,138	1,894
2034	0	436	1,319	2,197
2035	0	500	1,500	2,500
2036	0	500	1,500	2,500
2037	0	500	1,500	2,500
2038	0	500	1,500	2,500
2039	0	500	1,500	2,500
2040	0	500	1,500	2,500

- **The Low Scenario** assumes modest adoption, limited to a few mid-size enterprise data centers.
- **The Mid Scenario** represents AES Indiana's current planning baseline. It assumes successful development of one or more hyperscale campuses and moderate- to mid-size data centers, with a ramp-up to 1,500 MW by 2035.
- **The High Scenario** assumes accelerated growth driven by regional clustering, robust site development, and large procurement contracts. It reflects scenarios in which multiple hyperscale, mid-size, or colocation providers establish operations concurrently.

As shown in Figure 5-19 above, all three scenarios show a ramp from 2027 to 2035, assuming no further data center growth after 2035. This reflects industry practices, in which customers aim to achieve commercial operation within 24 to 36 months of project initiation. The forecast is expressed in incremental peak, representing additional demand expected on the system.

These ramp assumptions were informed by regional project-siting data, standard development timelines, and consultation with internal teams engaged in large load customer service planning.

Ongoing Monitoring and Future Updates

As additional clarity emerges, the scenarios presented here may be refined, either upward or downward, in the future. AES Indiana's approach emphasizes transparency, flexibility, and proactive planning to ensure system readiness.

Section 6: Resource Options

170 IAC 4-7-4(11) and 170 IAC 4-7-4(31)

AES Indiana has a diverse portfolio of existing resources, including coal, natural gas, wind, solar, batteries, demand response, and energy efficiency.

The Company received IURC approval to procure an additional solar plus battery resource, Crossvine Solar (IURC Cause No. 46113), to convert the last two coal-fired units at Petersburg to natural gas (IURC Cause No. 46022), and to build an additional storage resource, Pike County BESS (IURC Cause No. 45920).

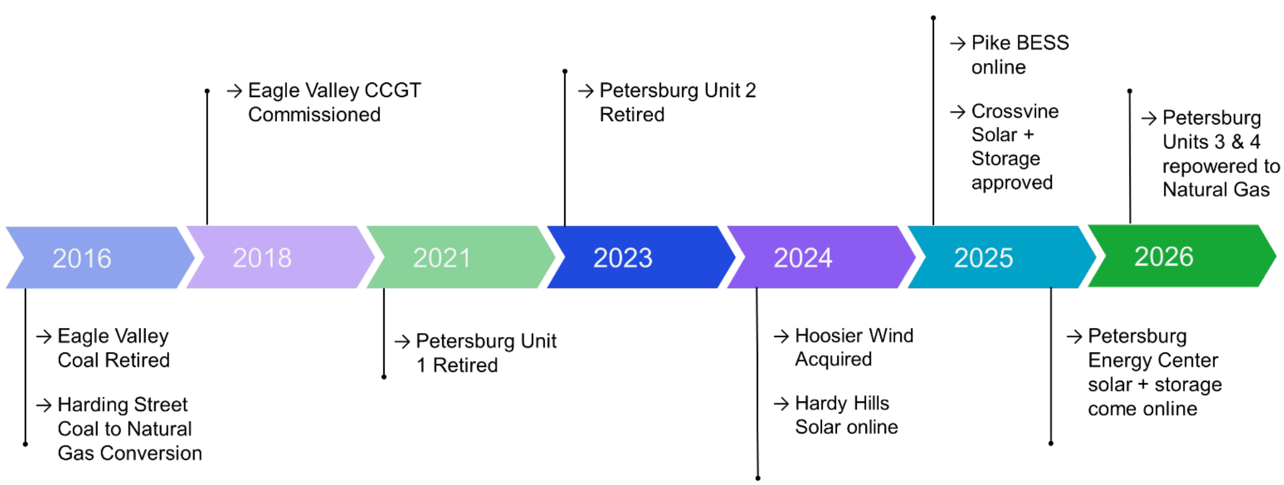
For potential replacement resources, AES Indiana examined natural gas, wind, solar, solar plus storage, stand-alone storage, small modular nuclear reactors, demand response, and energy efficiency.

6.1 Existing AES Indiana Resources

170 IAC 4-7-4(4) and 170 IAC 4-7-6(a)(2)

AES Indiana's portfolio has transformed over the last 15 years, becoming less dependent on coal, particularly. Figure 6-1 highlights the more substantial changes.

Figure 6-1: Transitions in the AES Indiana Portfolio



6.1.1 Existing Supply Side Resource

170 IAC 4-7-6(a)(1)

AES Indiana operates the coal-fired Petersburg Generating Station in Pike County, Indiana. This plant has four units. Unit 1 was retired May 31, 2021, and Unit 2 was retired May 31, 2023, as a result of the 2019 IRP. Units 3 and 4 are scheduled to be repowered to natural gas in 2026 as a result of the 2022 IRP. Figure 6-2 further details AES Indiana's existing coal power units.

Figure 6-2: AES Indiana: Existing Coal Power Units

Coal Units	Technology	ICAP (MW)	In-Service Year	Estimated Last Year In-Service
Petersburg Unit 3	Coal ST	520	1977	2026
Petersburg Unit 4	Coal ST	520	1986	2026
	Total Coal:	**1,040**		

AES Indiana operates several natural gas-fired generators using steam turbines ("ST"), combustion turbines ("CT"), and combined cycle ("CCGT") technology. The Harding Street and Georgetown plants are located in Marion County, Indiana. The Eagle Valley CCGT is located in Morgan County, Indiana. See Figure 6-3.

Figure 6-3: AES Indiana: Existing Natural Gas Units

Unit Name	Technology	Summer ICAP (MW)	In-Service Year	Estimated Last Year In-Service
Eagle Valley	Combined cycle	671	2018	
Harding Street ST5	Steam turbine	100	1958	2040
Harding Street ST6	Steam turbine	98	1961	2040
Harding Street ST7	Combustion turbine	420	1973	2040
Harding Street GT4	Combustion turbine	75	1994	
Harding Street GT5	Combustion turbine	75	1995	
Harding Street GT6	Combustion turbine	160	2002	
Georgetown GT1	Combustion turbine	75	2000	
Georgetown GT4	Combustion turbine	75	2001	
Petersburg Unit 3	Steam turbine	526	2026	
Petersburg Unit 4	Steam turbine	526	2026	
	Total Natural Gas:	**2,801**		

AES Indiana has a Power Purchase Agreement ("PPA") with Lakefield Wind Park, located in southern Minnesota. Lakefield Wind Park does not receive capacity credit because of its interconnection service. Lakefield's PPA expires within the next ten years. Since Lakefield Wind Park is not in Indiana and does not have interconnection service, it is unlikely that AES Indiana will try to retain this contract past its expiration.

Hoosier Wind Park is a wind project located in northwest Indiana and is advantageous because of its proximity to AES Indiana's load and firm capacity in MISO's Zone 6; therefore, the company acquired this asset in February 2024.

AES Indiana has contracted with several solar installations under its Rate REP structure on its distribution system in Marion County, Indiana. These solar resources reduce AES Indiana's load obligation. AES Indiana has also announced the additions of the following:

→ Hardy Hills Solar, a solar resource in Clinton County, Indiana
→ Petersburg Energy Center, a solar plus Battery Energy Storage System ("BESS") hybrid resource in Pike County, Indiana
→ Pike County Battery Energy Storage System, a standalone storage resource in Pike County, and
→ Crossvine, a solar plus Battery Energy Storage System ("BESS") hybrid resource in Dubois County.

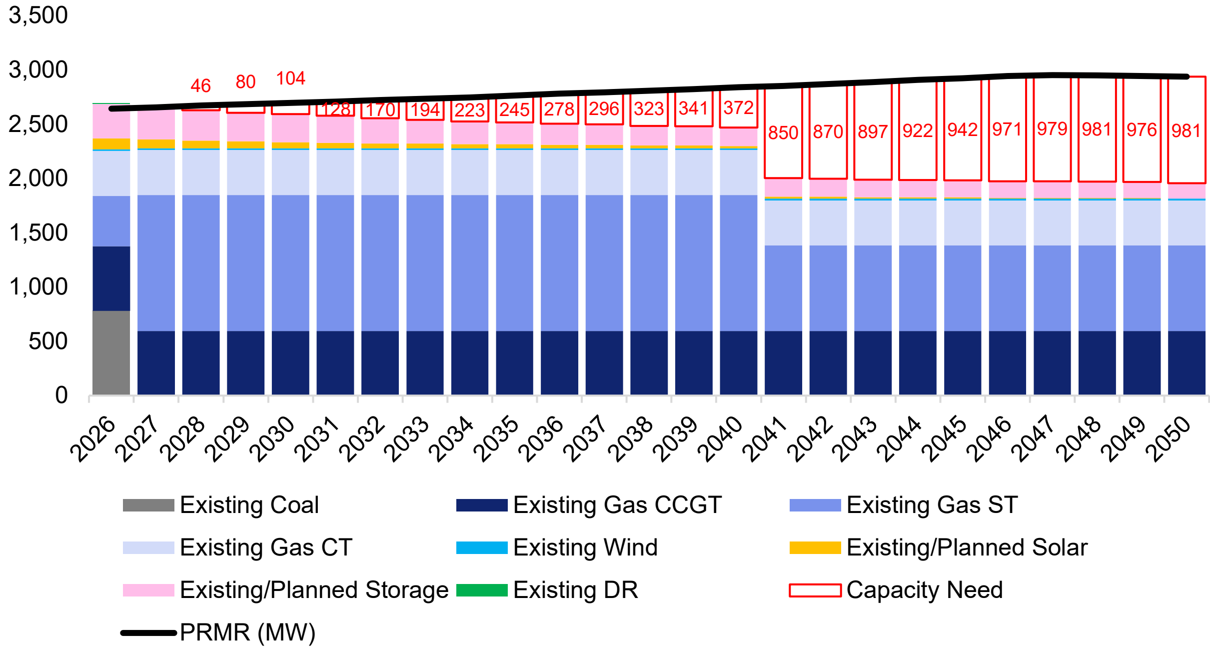
These projects are expected to come online in 2025-2027 as a result of AES Indiana's 2019 and 2022 IRPs. Figure 6-4 details AES Indiana's existing and IURC-approved wind, solar, and storage projects.

Figure 6-4: AES Indiana Existing and IURC-Approved Renewable and Storage

Resource Name	Technology	ICAP (MW)	In-Service Year/PPA Start	Estimated Last Year In-Service/ PPA End
Hoosier	Wind	100	2009	
Lakefield	Wind	200	2011	2031
Rate REP	Solar	96	Various	Various
Hardy Hills	Solar	195	2024	
Pike County	4-Hour Storage	200	2025	
Pete Energy Center	Solar	250	2025	
	4-Hour Storage	45	2025	
Crossvine	Solar	85	2027	
	4-Hour Storage	85	2027	
	Total Wind:	**300**		
	Total Solar:	**626**		
	Total Storage:	**330**		
	Grand Total:	**1,256**		

Figure 6-5 shows the Company's current capacity position. AES Indiana develops a notably shorter capacity position due to the age-based retirements of the Harding Street steam-powered generators at year-end 2040.

Figure 6-5: AES Indiana: Winter Capacity Position



6.2 Supply Side Resource Options

170 IAC 4-7-4(6), 170 IAC 4-7-4(7), and 170 IAC 4-7-6(b)(3)(A)

AES Indiana considered several commercially viable technologies for its supply-side modeling:

Renewables and Storage

- Wind
- Utility-Scale Single-Axis Tracking Photovoltaic Solar
- Stand-Alone Storage of 4- ,6- and 8-hour durations
- Solar Plus Storage Hybrid

Natural Gas

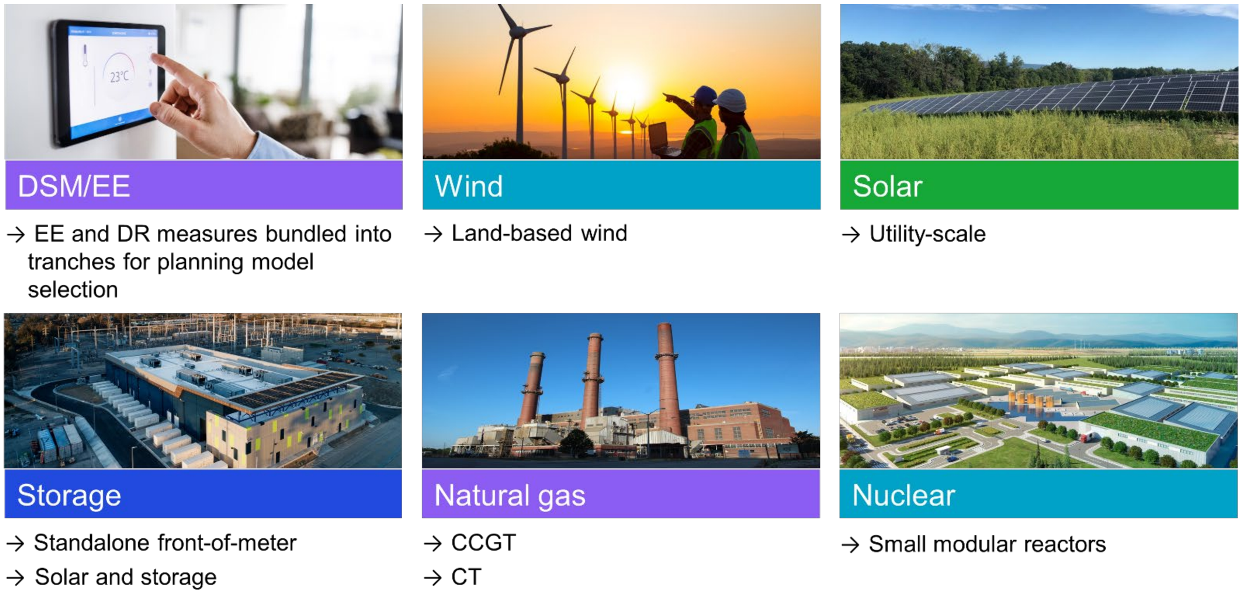
- Combined Cycle Natural Gas Turbine (“CCGT”)
- Simple Cycle Combustion Turbine (“Frame CT”)
- Reciprocating Internal Combustion Engines (“RICE Engines”)

Nuclear

- Small Modular Reactor (“SMR”)

Figure 6-6 describes the replacement resources that were modeled in AES Indiana’s 2025 IRP.

Figure 6-6: New Replacement Resources Modeled in AES Indiana's 2025 IRP



Ownership Structure

AES Indiana's capacity expansion model is agnostic to the ownership structure and captures all the costs associated with financing and operating new resources.

Capital Costs

Capital costs for newly constructed resources were developed using NREL's 2024 Annual Technology Baseline ("ATB"), Wood Mackenzie's 2024 Base Case Update, and Bloomberg New Energy Finance's ("BNEF") Second Half ("2H") 2023 Levelized Cost of Energy ("LCOE") Report. NREL's ATB is a public data source, while Wood Mackenzie and BNEF require subscriptions to access their data.

Capital costs were also informed by AES Indiana's 2024 All Source RFP and 2025 Thermal RFP, both administered by Charles River Associates. AES Indiana aggregated proposals received through its RFPs by technology type and calculated the average cost for each technology. This estimate serves as the base cost for solar and storage in 2026. Gas and wind costs were further adjusted due to the small number of bids received.

AES Indiana then used the average trend from Wood Mackenzie, NREL, and BNEF capital cost forecasts by technology type to determine the changes to the cost starting point over the planning period. This approach captures the potential technology learning curve or cost efficiencies from improvements in design and manufacturing processes.

SMR capital cost estimates were developed using RFP responses and secondary sources. Please see Confidential Attachment 6-1a and b for a detailed description of the capital cost assumptions used in AES Indiana's 2025 IRP.

In addition to project costs, AES Indiana added an interconnection cost to resource capital costs that varied by technology. Charles River Associates provided a levelized estimate of the cost of utilizing tax equity to fund projects that qualify for the production tax credit or investment tax credit.

6.2.1 Tax Credits

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA") was signed into federal law. The bill contained significant changes to tax credits for wind and solar. AES Indiana incorporated this into the IRP for three of the four scenarios. Figure contains the base case tax credit assumptions for the IRP modeling. Tax credits for storage and nuclear were relatively unchanged, but wind and solar tax credits were pulled forward and expire at the end of 2029 for projects that achieve safe harbor in 2025.

AES Indiana considered a scenario in which tax credits are fully reinstated and extended through the end of the study period.

Figure 6-7: OBBBA: Base Case Tax Credit Assumptions in IRP

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036 +
Solar*	ITC	30%	30%	30%	30%	30%	0%	0%	0%	0%	0%	0%	0%
Storage	ITC	30%	30%	30%	30%	30%	30%	30%	30%	30%	23%	15%	0%
Wind*	PTC**	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Nuclear	PTC**	100%	100%	100%	100%	100%	100%	100%	100%	100%	75%	50%	0%

* Wind and Solar: assumed that selectable projects in the IRP achieved safe harbor for begin construction in 2025

** PTC shown as percentage of $/MWh PTC value

6.2.2 Capacity Accreditation

New supply-side resources are assumed to be in the state of Indiana and capable of providing firm capacity to MISO's Zone 6. MISO's seasonal capacity construct requires differentiation of capacity credit across seasons. This has a profound effect on wind and solar, both of which have capacity credits determined by their effective load-carrying capability ("ELCC"), or the amount of generation these resources provide during times of need. AES Indiana's resource accreditation for the 2025 IRP is based on a combination of sources, including indicative MISO direct loss of load ("DLOL") modeling, MISO-provided AES Indiana indicative DLOL values for existing resources, and internal projections for future penetration levels of various technologies, particularly solar and storage.

Thermal Resources and SMR

MISO provided indicative DLOL accreditation values for all AES Indiana thermal assets. The indicative values were for PY 2025/2026 and were based on actual unit performance for 2022-2024. AES Indiana made adjustments to account for unit forced outages that are rolling off in future planning years, and the final values established seasonal accreditation values for existing and new thermal assets. Figure contains seasonal capacity accreditation for thermal and nuclear assets in the IRP. These capacity values are maintained throughout the study period. AES Indiana acknowledges that capacity accreditation under DLOL will vary year to year based on unit performance, shifting high-risk hours, and other market rule changes.

Figure 6-8: Thermal and Nuclear Firm Capacity Credit for IRP

	Summer	Fall	Winter	Spring
Gas CCGT	94%	95%	85%	85%
Gas CT	85%	85%	85%	85%
Gas ST	75%	75%	75%	75%
Oil	70%	70%	80%	80%
Nuclear	94%	90%	87%	81%

Figure compares the indicative DLOL capacity volumes received from MISO compared to the IRP assumptions for AES Indiana's existing natural gas resources. AES Indiana established seasonal capacity credit values that reflect a conservative view of forward-looking capacity credit estimates for thermal resources in the IRP modeling. Any deviations from these forecasts could be accommodated by future resource decisions, short-term capacity purchases, or sales.

Figure 6-9: Firm Capacity for Existing Thermal – IRP Assumption vs MISO Indicative DLOL (Firm MW)

Type	Variable	Summer	Winter
CCGT	Indicative DLOL	640	611
	IRP Assumption	611	595
Gas ST and CT	Indicative DLOL	862	882
	IRP Assumption	855	855
Total Gas*	Indicative DLOL	1,502	1,493
	IRP Assumption	1,466	1,450
	Difference	-36	-44

**Eagle Valley, Harding Street, Georgetown*

Solar, Wind, and Storage

MISO has provided indicative DLOL accreditation values for all asset types, but the most uncertainty lies in the capacity value for renewables and storage.

For wind, AES Indiana leveraged MISO-provided, unit-specific DLOL values for Hoosier Wind as a proxy for future generic wind accreditation.

For solar, MISO has provided multiple views of solar capacity value. In all forecasts, the capacity value of solar decreases as more solar is installed on the system. In the MISO RRA study published in late 2024, MISO produced DLOL capacity values based on installed capacity volumes that far exceed what is commercially executable, even under an aggressive assumption about the percentage of the MISO generation queue that could be installed. Additional uncertainty added from the OBBBA lends support for an installed capacity volume moving forward that is far less than what MISO used in the RRA study. Therefore, AES Indiana took a more gradual approach to the ELCC declines in all seasons, as it is expected that installed solar capacity will take a more linear step change higher through the early 2030s.

For battery storage, MISO continues to refine the methodology for modeling storage in the DLOL approach. Early indications from MISO pointed to a 4-hour storage capacity of 30-40% in the winter, and more recent modeling suggests accreditation above 90% even as more storage is added to the system. AES Indiana leveraged a combination of MISO publications and other ISO/RTO accreditation reports[35,36] to develop a more conservative approach to winter accreditation for 4-hour storage. The 2025 IRP used a declining ELCC from 95% to 50% over the study period, accounting for increasing duration of scarcity events as more storage is added to the system and the net load curve flattens. Longer duration systems are expected to be required. AES Indiana will continue to participate in MISO RASC and LOLE stakeholder meetings, and we will account for changes in accreditation in future IRPs.

Figure 6-10: Seasonal Capacity Accreditation for Solar, Wind, and Storage

	Solar				4-Hour Storage				Wind			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2026	39%	24%	16%	24%	95%	95%	95%	95%	7%	11%	17%	12%
2027	34%	21%	13%	21%	95%	95%	95%	95%	7%	11%	17%	12%
2028	30%	19%	11%	19%	85%	85%	95%	95%	7%	11%	17%	12%
2029	28%	17%	10%	18%	85%	85%	80%	85%	7%	11%	17%	12%
2030	25%	16%	9%	16%	85%	85%	78%	85%	7%	11%	17%	12%
2031	23%	15%	8%	15%	85%	85%	76%	85%	7%	11%	17%	12%
2032	22%	14%	7%	14%	85%	85%	70%	85%	7%	11%	17%	12%
2033	20%	13%	7%	13%	85%	85%	66%	85%	7%	11%	17%	12%
2034	19%	12%	6%	12%	85%	85%	63%	85%	7%	11%	17%	12%
2035	18%	11%	6%	12%	85%	85%	61%	85%	7%	11%	17%	12%
2036	17%	10%	5%	11%	85%	85%	59%	85%	7%	11%	17%	12%
2037	16%	10%	5%	10%	85%	85%	57%	85%	7%	11%	17%	12%
2038	15%	9%	4%	10%	85%	85%	55%	85%	7%	11%	17%	12%
2039	14%	9%	4%	9%	85%	85%	54%	85%	7%	11%	17%	12%
2040	13%	8%	3%	9%	85%	85%	52%	85%	7%	11%	17%	12%
2041	12%	8%	3%	8%	85%	85%	51%	85%	7%	11%	17%	12%
2042	12%	7%	3%	8%	85%	85%	50%	85%	7%	11%	17%	12%
2043	11%	7%	2%	8%	85%	85%	49%	85%	7%	11%	17%	12%
2044	10%	6%	2%	7%	85%	85%	48%	85%	7%	11%	17%	12%
2045	10%	6%	2%	7%	85%	85%	47%	85%	7%	11%	17%	12%

[35] https://spp.org/documents/72346/2024%20spp%20elcc%20wind%20solar%20&%20esr%20report.pdf
[36] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf

6.2.3 Solar, Wind, and Storage

Figure below provides a summary of the new solar, wind, and storage resource characteristics included in AES Indiana's capacity expansion model.

Figure 6-11: Wind, Solar, and Storage Unit Parameters

	Generic Project Size (ICAP MW)	Capacity Factor (%)	Round-Trip Efficiency (%)	2030 Reference Case CAPEX ($/kW)	2030 Low CAPEX ($/kW)	Fixed O&M (2030$/kW-year)
Wind	50	40%	-	$3,391	$2,543	$55
Solar	25	24.50%	-	$2,004	$1,107	$17
Hybrid Solar/Storage	25/20	24.50%	85%	$3,357	$1,538	$25
4-Hour Storage	20	-	85%	$1,889	$1,180	$28
6-Hour Storage	20	-	85%	$2,980	$1,626	$39
8-Hour Storage	20	-	85%	$3,779	$2,072	$55

Figure 6-12: Base Capital Costs for New Wind Resources

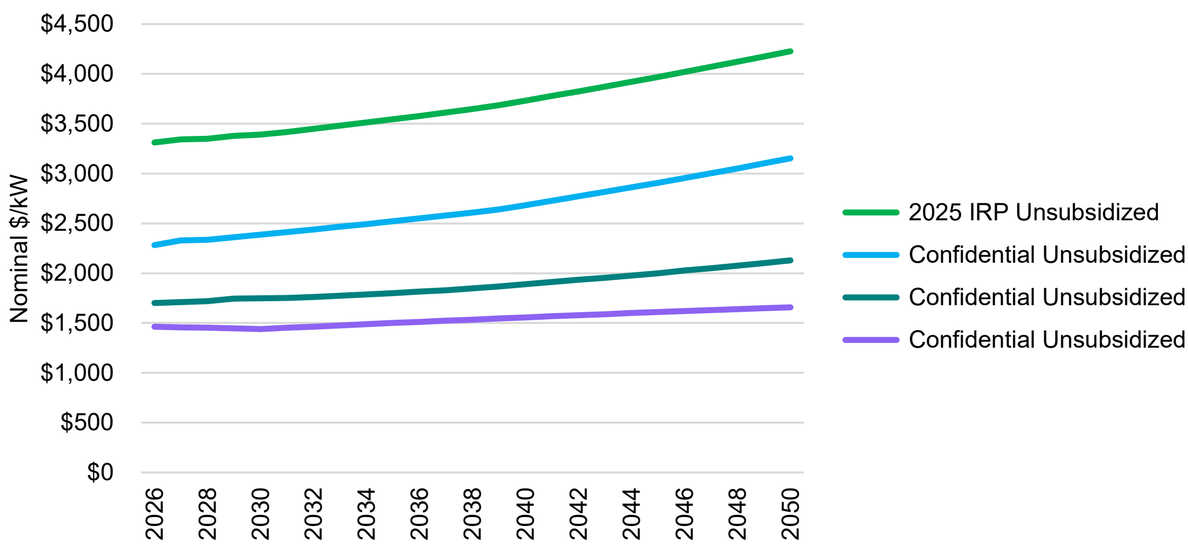


Figure 6-13: Base Capital Costs for New Solar Resources

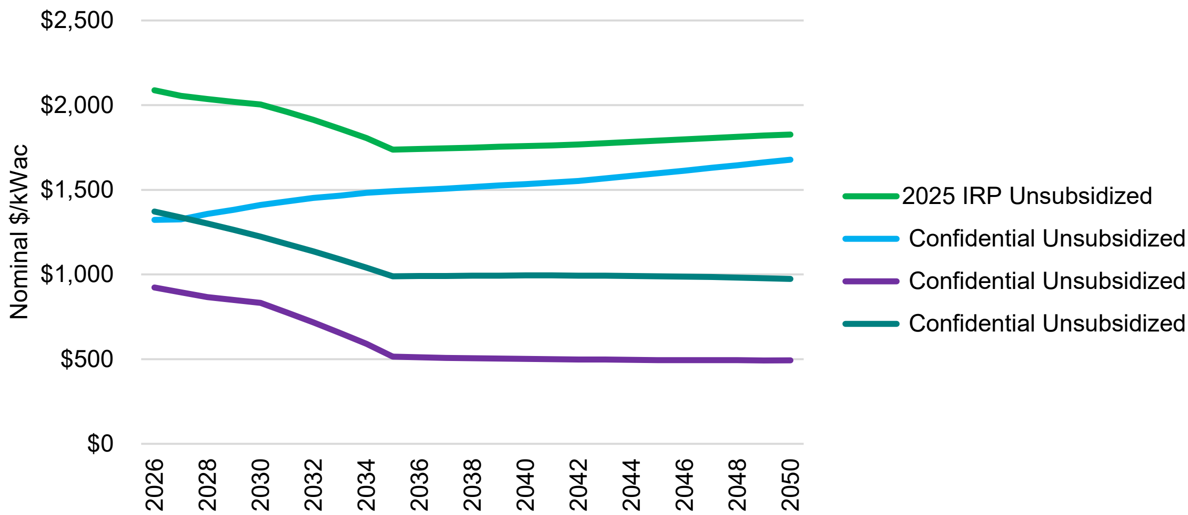


Figure 6-14: Base Capital Costs for New Hybrid Resources

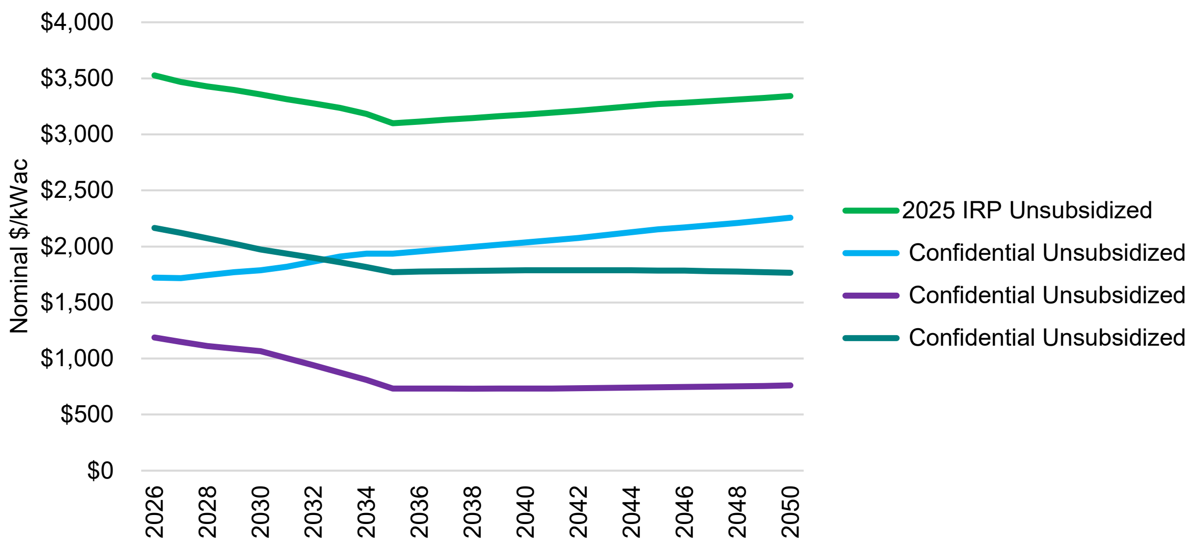


Figure 6-15: Base Capital Costs for New 4-Hour Storage Resources

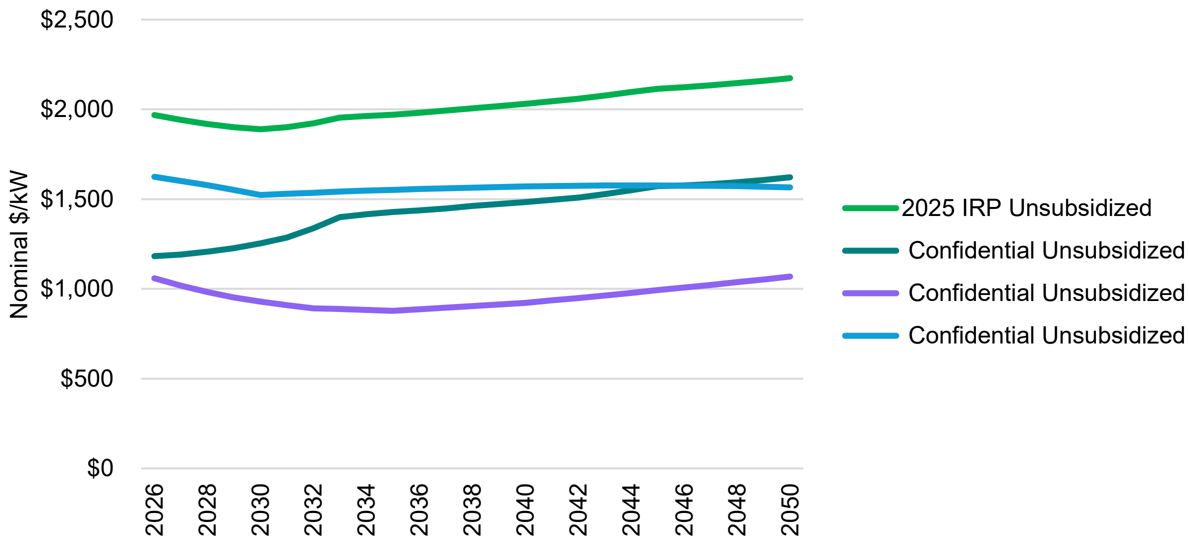
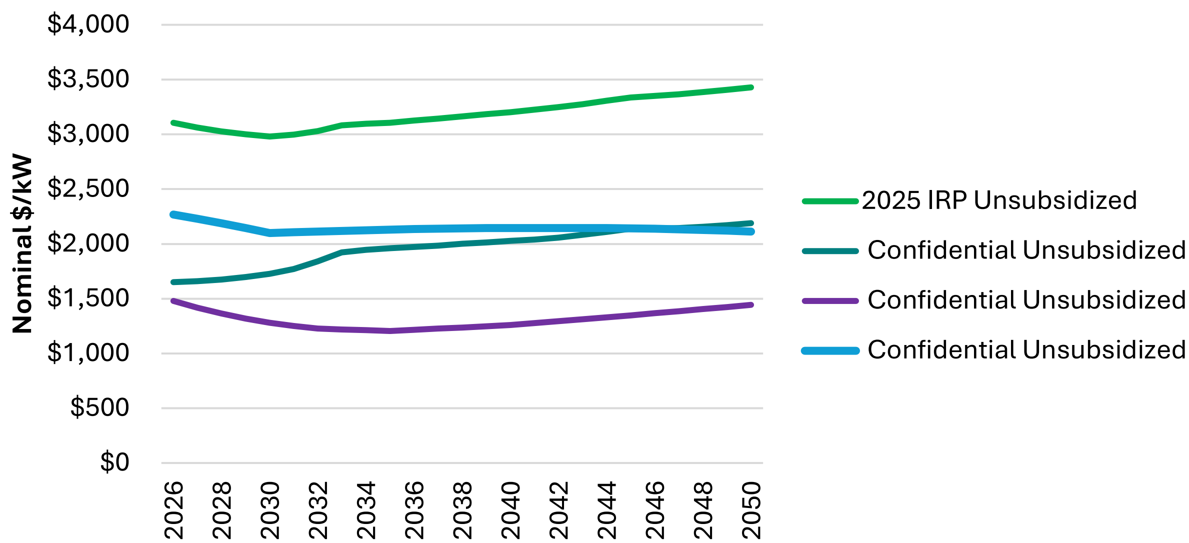


Figure 6-16: Base Capital Costs for New 6-Hour Storage Resources



6.2.4 Natural Gas Resources

This section provides a brief description of each modeled natural gas resource, along with key modeling assumptions.

→ Combined Cycle Natural Gas Turbine (CCGT)

→ Simple Cycle Combustion Turbine (Frame CT)

→ Reciprocating Engines

CCGT Resource Description

The typical combined cycle consists of natural gas turbines discharging waste heat into a heat recovery steam generator ("HRSG"). The HRSG supplies steam that is expanded through a steam turbine cycle, driving an electric generator. Combined cycle units are the most efficient fossil-fueled power plants available. Additionally, the units have relatively low pollutant emissions, low water consumption, reduced space requirements, and modular construction. AES Indiana modeled new generic CCGTs after AES Indiana's Eagle Valley CCGT, a 2x1 configuration with two F-class natural gas turbines, each with an HRSG feeding a single steam turbine generator. It was assumed that a new combined cycle would be located at Eagle Valley.

Frame CT Resource Description

Frame CTs are a mature technology, widely used for peaking applications. AES Indiana's existing units include Georgetown Unit 1, which reached commercial operation in 2000, and Harding Street Unit 6, which reached commercial operation in 2002. AES Indiana also purchased Georgetown Unit 4 in 2007. AES Indiana modeled new generic Frame CTs after Harding Street Unit 6.

Reciprocating Engine Resource Description

Reciprocating engines are characterized by low startup costs, fast ramp rates, and the ability to turn engines off to run at very low minimums. They range in size from 3 MW to 18 MW but are commonly installed as a bank of engines. AES Indiana's 2025 IRP analysis assumed a bank of three 18 MW units for a total of 54 MW as a selectable resource.

Unit Cost Information

The base costs were developed using an average of NREL's 2024 Annual Technology Baseline ("ATB"), Wood Mackenzie's 2024 Base Case Update, and Bloomberg New Energy Finance's ("BNEF") Second Half ("2H") 2023 Levelized Cost of Energy ("LCOE") Report. Responses to AES Indiana's 2024 RFP and 2025 Thermal RFPs also helped to inform the capital cost assumptions for natural gas resources. Final capital costs include an interconnection cost estimate using MISO's queue data. Data for reciprocating engines is based on an aggregate of publicly available cost estimates. Reciprocating engines are not installed at the same volume as frame CTs or CCGT, so there is less transparency into recent pricing trends.

The fixed costs include firm natural gas delivery costs, which were derived from AES Indiana's internal estimates based on conversations with other marketers and pipelines. These conversations estimated a baseline of $0.50/MMBtu/day in fixed reservation fees, which, for a CCGT, equates to $29.94/kW-yr and $29.20/kW-yr. For the Challenged Gas Infrastructure Scenario, the fixed reservation fees were increased to $0.65/MMBtu/day, which equates to $38.92/kW-yr for a CCGT and $37.96/kW-yr. Fixed costs for thermal resources are levelized to remove the cyclical nature of maintenance outages.

Figure 6-17: Generic Thermal Assets – Key Modeling Inputs

	Combustion Turbines	Reciprocating Engines	Combined Cycle
Summer ICAP (MW)	240	54	640
Winter ICAP (MW)	240	54	700
Heat Rate at Max (Btu/kWh)	10,012	7,400	6,200
2030 Variable O&M ($/MWh)	$1.56	$7.60	$3.40
2030 Fixed O&M ($/kW-year)	$22.93	$22.93	$30.14
2030 Base Firm Gas Transportation ($/kW-year)	$32.24	$32.24	$33.06
2030 Base Total Fixed Costs ($/kW-year)	$55.16	$55.16	$63.20
2030 High Firm Gas Transportation ($/kW-year)	$41.91	$41.91	$42.98
2030 High Total Fixed Costs ($/kW-year)	$64.84	$64.84	$73.12
2030 Reference Case CAPEX ($/kW)	$1,627	$2,215	$2,771
2030 Low CAPEX ($/kW)	$1,007	$2,215	$2,078
2030 High CAPEX ($/kW)	$2,115	$2,714	$3,464

Figure 6-18: Base Capital Costs for Natural Gas CCGT

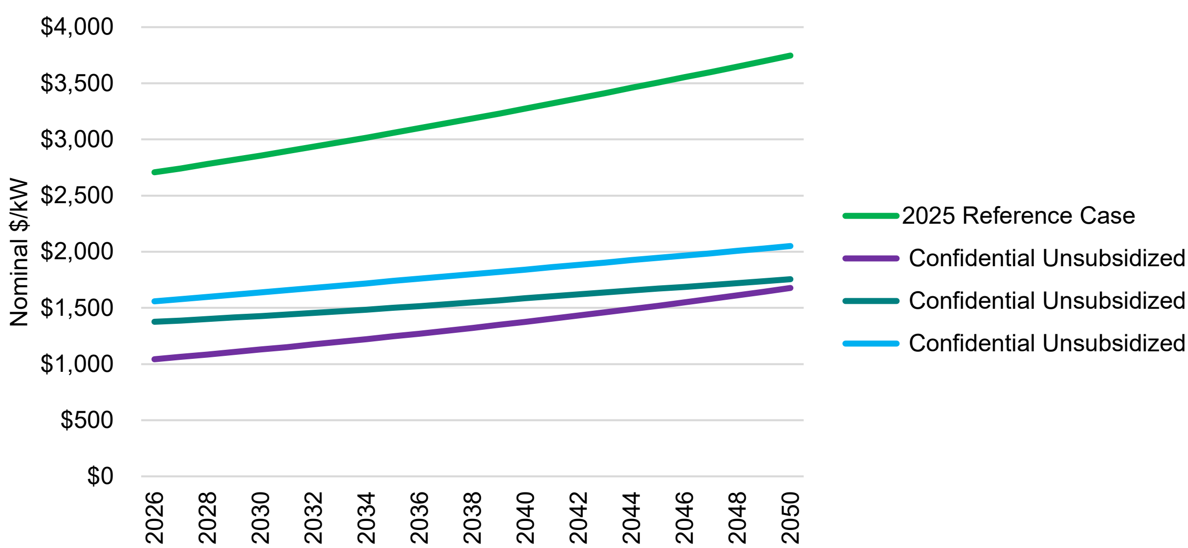
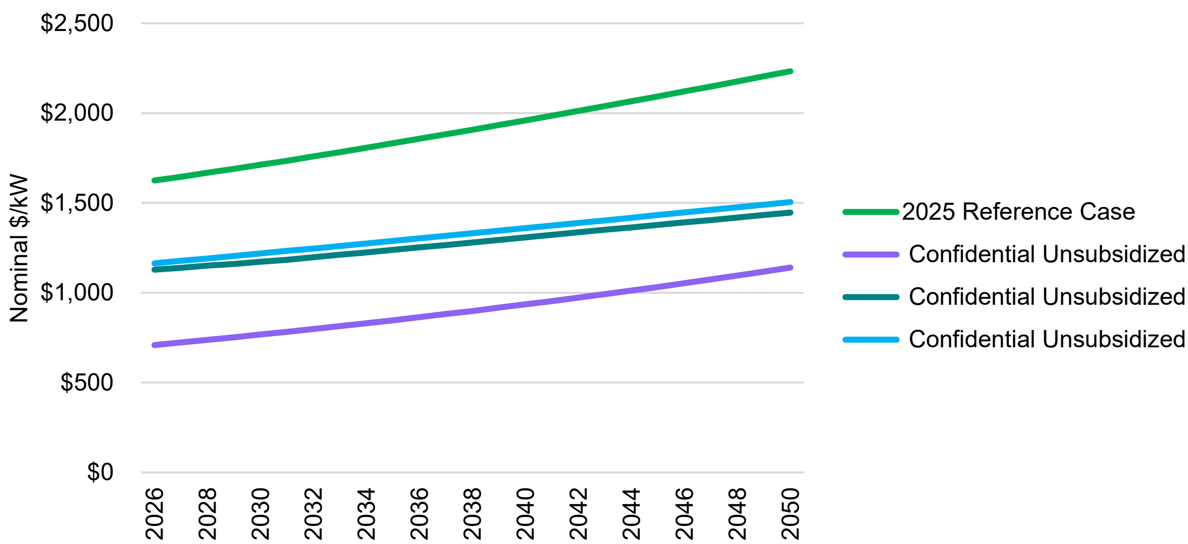


Figure 6-19: Base Capital Costs for Natural Gas CT



6.2.5 Small Modular Reactors

Small Modular Reactor Resource Description

Small Modular Reactors (SMRs) are advanced nuclear fission reactors designed to produce up to a few hundred megawatts of electricity per unit—about one-third the capacity of traditional nuclear power plants. Smaller size allows for factory fabrication and transport to installation sites. This streamlines construction and reduces costs.

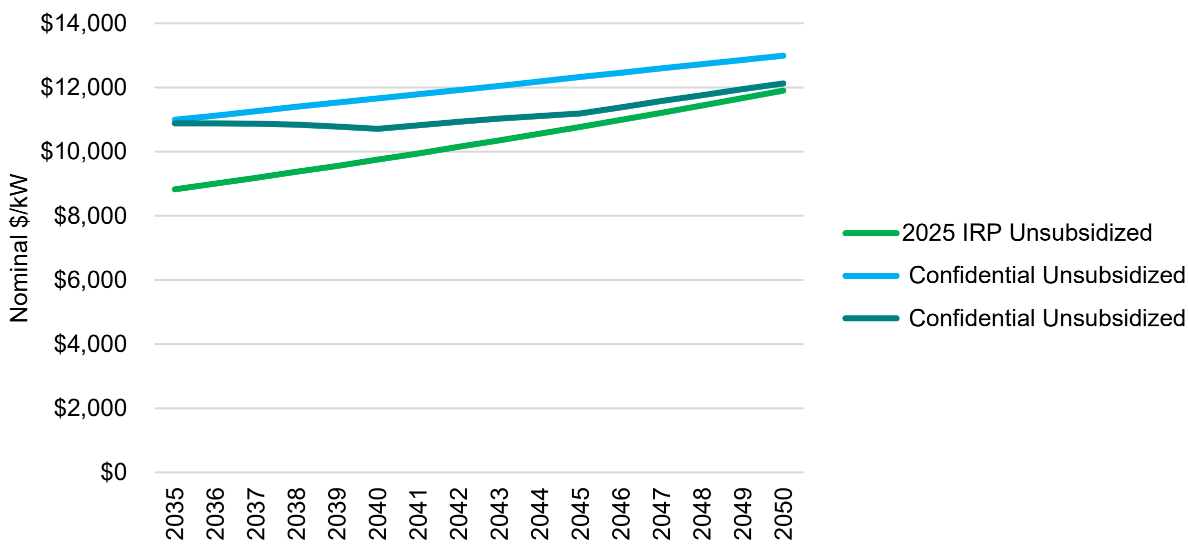
Figure 6-20: Small Modular Reactor Resource Characteristics

Small Modular Reactor Resource Summary
→ **Project Size**: 470 MW ICAP
→ **Heat Rate at Max Economic Load:** 9,180 Btu per kWh
→ **Useful Life:** 40 years
→ **Spring Capacity Credit:** 91%
→ **Summer Capacity Credit:** 91%
→ **Fall Capacity Credit:** 91%
→ **Winter Capacity Credit:** 95%

Capital Costs and Fixed O&M

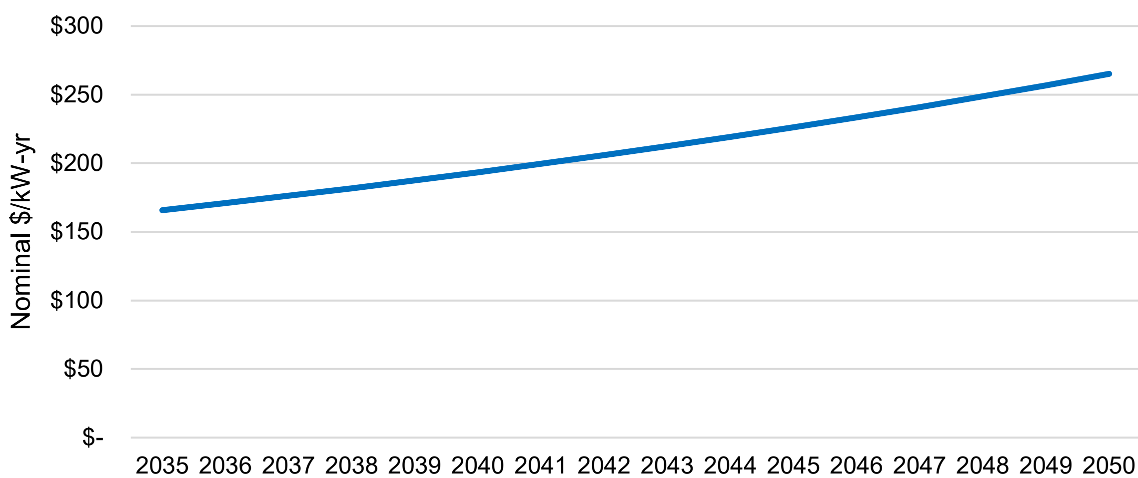
AES Indiana used capital costs obtained from NREL's 2024 Annual Technology Baseline ("ATB") and Wood Mackenzie's 2024 Base Case Update, along with developer estimates received in its 2024 RFP, to help inform the base cost assumptions for SMRs as shown in Figure 6-21.

Figure 6-21: Base Capital Costs for SMRs



Estimates for fixed operating and maintenance costs for SMRs were based on NREL's 2024 Annual Technology Baseline ("ATB") and Wood Mackenzie's 2024 Base Case Update and are shown in Figure 6-22

Figure 6-22: Fixed O&M for a New SMR Resource



6.3 Summary of Supply Side Resources

170 IAC 4-7-4(6) and 170 IAC 4-7-6(b)(3)(A)

Since the 2022 IRP, the energy industry has experienced significant changes. Anticipated demand has surged. Emphasis has been placed on the increased electricity requirements of planned data centers. Additionally, the One Big Beautiful Bill Act ("OBBBA") has altered the financial landscape for renewable energy projects. This legislation phases out tax credits for wind and solar by the end of the decade, while incentives for standalone storage and SMRs remain largely unaffected. Furthermore, markets are in an inflationary state post-COVID. Increased demand is pitted against higher-cost resources; those resources become even more costly. AES Indiana finds itself planning for new demand in a new market.

AES Indiana's supply-side replacement options include a broad range of commercially viable technologies.

- Renewable energy resources include wind and solar. Wind energy is considered primarily for Northern Indiana, where it offers moderate capacity factors but faces challenges such as transmission congestion and siting constraints. Solar energy is represented by utility-scale, single-axis tracking photovoltaic systems. These solar resources can be paired with battery storage to form hybrid systems, enabling stored energy to be dispatched during peak periods rather than curtailed.

- Dispatchable resources include natural gas and storage. Modeled natural gas resources are combined cycle, combustion turbines, and reciprocating engines. Standalone energy storage systems with four-, six-, and eight-hour durations are also considered.

- SMRs were also included. SMRs are an emerging low-carbon technology with the potential for firm generation, though they carry uncertainty regarding upfront costs and lack a proven performance record.

6.4 Demand Side Resource Options

170 IAC 4-7-4(6), 170 IAC 4-7-6, and 170 IAC 4-7-6(b)(2)(A)

6.4.1 Existing Demand Side Resources

AES Indiana is in the first year of a two-year DSM Plan, spanning 2025 and 2026. The portfolio of current DSM programs was approved by the IURC on January 8, 2025, in Cause No. 46081. This comprehensive set of programs provides energy efficiency opportunities for all AES Indiana customers, with a gross first-year savings goal of 176,024,473 kWh.

The most recent evaluated DSM Plan covered only 2024 and contributed approximately 148,077,761 Ex Post Net kWh in annual energy savings and approximately 78 MW in demand savings.[37] The actual 2024 evaluated energy savings are shown in Figure 6-23 below.

Figure 6-23: Evaluated 2024 DSM Program Energy Savings (kWh)[38]

	DSM Program	Evaluated 2024 Program Achievement (Ex Post Net kWh)[39]
Residential	Residential Demand Response	-
	Efficient Products	9,738,575
	Home Energy Reports	30,254,165
	Income Qualified Weatherization	4,911,934
	Multifamily Direct Install	2,827,309
	School Kits	3,932,045
	Total Residential	**51,664,027**
Commercial	Demand Response	-
	Custom	21,799,883
	Prescriptive	72,501,697
	Small Business Direct Install	2,112,155
	Total Commercial and Industrial	**96,413,734**
	Total 2024 Portfolio	**148,077,761**

Residential

DSM Residential Demand Response

Known as *CoolCents®* in customer-facing materials, this air conditioning load management (ACLM) program has been offered since 2003 and is the longest, continually offered DSM program at AES Indiana. *CoolCents®* is the second-largest DSM program by customer

[37] Ex Post Net reflects the net impact of DSM programs following an annual third-party evaluation. More information can be found in the AES Indiana 2024 Demand Side Management Portfolio Evaluation Report that was filed with the IURC on July 23, 2025, under AES Indiana's DSM Plan docket (IURC Cause No. 45898).

[38] *Id.*

[39] *Id.*

participation and the largest by peak demand reduction (MW). As of the end of 2024, AES Indiana has deployed approximately 63,000 residential demand response devices (up from 52,000 in the 2022 IRP).[40] New participants are mainly acquired through smart thermostat and smart water heater offerings available through multiple AES Indiana program channels, including program direct-install, program rebates, and customer bring-your-own device.

The Residential Demand Response program reduces peak demand by controlling residential cooling equipment and electric water heaters during periods of peak system demand, delivery constraints within certain load zones, or high locational marginal prices. AES Indiana does this by remotely communicating with smart thermostats, direct-load air conditioner (AC) control switches (both one-way and two-way switches), direct-load control water heater switches, and smart electric water heaters.

In 2021, AES Indiana started testing demand response for water heater switches. To date, water heater switches have primarily been installed in multifamily units with electric hot water heaters, and current participation remains modest. AES Indiana continues to maintain water heater switches under the current DSM portfolio. It will continue to evaluate the demand response potential of water heater switches and smart water heaters for use as a Load Modifying Resource ("LMR"). As of 2025, this resource was not submitted to MISO as an LMR.

Efficient Products Program

AES Indiana offers customers opportunities to save energy through the Efficient Products program, including direct-install measures, energy-saving kits, and efficiency rebates. The program primarily comprises customer rebates for appliances, HVAC, and insulation measures. The program also includes efficient products available on the AES Indiana Marketplace, Virtual Home Energy Assessments, and energy-saving kits.

Income Qualified Weatherization

For customers with incomes at or below 200% of the federal poverty level, AES Indiana helps customers throughout its service territory save energy through direct installation of efficient products, home insulation and weatherization measures, and energy-saving kits. AES Indiana also distributes energy-saving measures (such as smart power strips, water-saving devices, and weatherstripping tape) through a Food Pantry component, which provides energy-saving kits to customers who visit food pantries and other community organizations.

Multifamily Direct Install

Through the Multifamily Direct Install (MFDI) program, AES Indiana customers living in multifamily buildings can save energy via the direct installation of efficient products and energy-saving kits.

Home Energy Reports

The largest residential program, in terms of participation and energy savings (kWh), is the Home Energy Report ("HER") program, comprising approximately 195,400 participants and 30,254,165 Ex Post Net kWh energy savings in 2024. Using each participant's household energy-use data

[40] 2024 Demand Side Management Evaluation Report, Indianapolis Power & Light Company d/b/a AES Indiana, July 23, 2025 (IURC Cause No. 45898).

and voluntarily provided home profile information, the reports provide comparisons with similar homes' energy use, along with energy-saving tips and seasonal information. Customers with a valid email address receive monthly electronic HERs by email and can access the program-affiliated web portal for more information on saving energy.

School Education Program

AES Indiana helps fifth-grade students and their families understand and identify opportunities to manage their energy use and provides free energy-efficiency kits, known as *Take Action Kits*, at participating schools. The kits include energy-saving products, installation instructions, a family activity guide, and a Home Energy Worksheet (HEW), which students and their guardians complete to indicate which kit measures they installed at home. Students and their guardians can visit the program website, which serves as a one-stop shop featuring instructional videos, e-learning modules, energy efficiency–themed games, and a link to the online HEW.

Commercial[41]

Custom Incentives Program

AES Indiana provides three offerings through the Custom Incentives program: Custom, RetroCommissioning (RCx), and Strategic Energy Management (SEM).

- → *Custom*: Offers incentives to C&I customers who install energy efficiency products that are not available through the Prescriptive Rebates program. AES Indiana calculates custom incentives based on a project's estimated annual energy savings.
- → *Retro-Commissioning (RCx)*: Offers incentives to C&I customers who conduct an approved Retro Commissioning study and provides additional incentives for any verified energy savings from implementing energy efficiency measures identified during the study.
- → *Strategic Energy Management (SEM)*: Encourages participants to develop an energy team at their facility to identify and implement no-cost or low-cost behavioral, operations and maintenance, and capital improvements to reduce energy consumption.

Prescriptive Rebates Program

Of the current Commercial and Industrial ("C&I") DSM program offerings, the most significant DSM program in 2024 was the Prescriptive Rebate program, with approximately 72,501 ex-post net MWh of energy savings. Through the Prescriptive Rebates program, AES Indiana offers incentives for C&I customers who install eligible energy-saving measures, such as efficient lighting, heating and cooling equipment, refrigeration measures, pumps and drives, and commercial kitchen equipment.

[41] 2024 Demand Side Management Evaluation Report, Indianapolis Power & Light Company d/b/a AES Indiana, July 23, 2025 (IURC Cause No. 45898).

Small Business Direct Install

AES Indiana has offered the Small Business Direct Install (SBDI) program since 2015 to provide small businesses with immediate energy savings and to help them identify other energy-saving opportunities. For business customers with no more than 200 kW of peak demand, the SBDI program includes a free on-site facility energy audit to identify energy efficiency opportunities and install no-cost energy-saving measures, primarily LED lighting and lighting controls.

Other

Interruptible Demand Response

AES Indiana has several Load Curtailment/Interruptible programs that are tariff offerings targeted to Commercial and Industrial ("C&I") customers. These include Rider 14: Interruptible Power, Rider 17: Curtailment Energy, and Rider 19: Interruptible Tariff. Since 2014, these programs have seen a significant decrease in participation and the amount of curtailable capacity provided. The DR programs were primarily targeted at customers with emergency backup generation. Customers are called upon periodically to operate emergency generation equipment on AES Indiana's behalf to reduce load. However, due to the 2014 National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines rulemaking, most customer emergency backup generation units are no longer eligible to participate in utility-sponsored programs because of air emission constraints.

As of 2025, AES Indiana had approximately 9 MW (Rider 17 and 14 combined) of demand response programs under contract with C&I customers. This is a decrease from the 45 MW available in 2014, largely due to departures by participating customers and EPA restrictions on emissions from diesel generators. In most cases, the incentives offered are adjusted annually to reflect changes in power market conditions.

Submitted in July of 2025, AES Indiana filed an Alternative Rate Plan ("ARP") proposing an Interruptible Demand Response ("IDR") program under Rider 19. The ARP contemplates a curtailment goal of 40 MW of summer capacity by 2028. Presently, the program has not been authorized by the IURC.

Figure 6-24 shows the demand response resources for which AES Indiana receives Load Modifying Resource ("LMR") capacity credit from MISO, totaling 59 Summer MW in 2025.

Figure 6-24: Registered Capacity of AES Indiana's 2025 Demand Response Programs

Demand Response Program	Winter UCAP (MW)	Spring UCAP (MW)	Summer UCAP (MW)	Fall UCAP (MW)
ACLM	-	50	50	50
Rider 17	1	1	1	1
Rider 14	8	8	8	8
Total	9	59	59	59

EV Charging Rewards

Expanding on early EV initiatives, AES Indiana launched two electric vehicle ("EV") demand response programs in early 2025 under IURC Cause No. 45843. The first program is the Managed Charging Rewards program, which shifts EV charging to off-peak times when demand is low. The second is the Off-peak Charging Rewards program (self-managed), which incentivizes customers to shift their charging to off-peak times. These pilots—targeting both residential and C&I customers—leverage smart EV charging devices to test peak mitigation potential.

Over the three-year term, AES will evaluate the demand response capabilities of these resources. While neither are currently eligible for MISO LMR registration, these programs may offer insights into how incentive-based measures complement DR strategies to reduce peak load during critical hours and assess their impact on residential and commercial EV load shapes. These programs are in early-stage deployment, with initial results expected by 2028.

6.4.2 AES Indiana's Demand Side Management Guiding Principles

170 IAC 4-7-6(b)(2)(C) and 170 IAC 4-7-6(b)(2)(F)

For over twenty-five years, AES Indiana has offered DSM programs to benefit customers. Since the 2022 IRP AES Indiana has continued this commitment by offering DSM programs that are informed by the following guiding principles:

- → DSM programs are inclusive for customers in all rate classes;
- → DSM programs are appropriate for AES Indiana's market and customer base;
- → DSM programs are cost-effective;
- → DSM programs modify customer behavior; and
- → DSM programs should provide continuity from year to year.

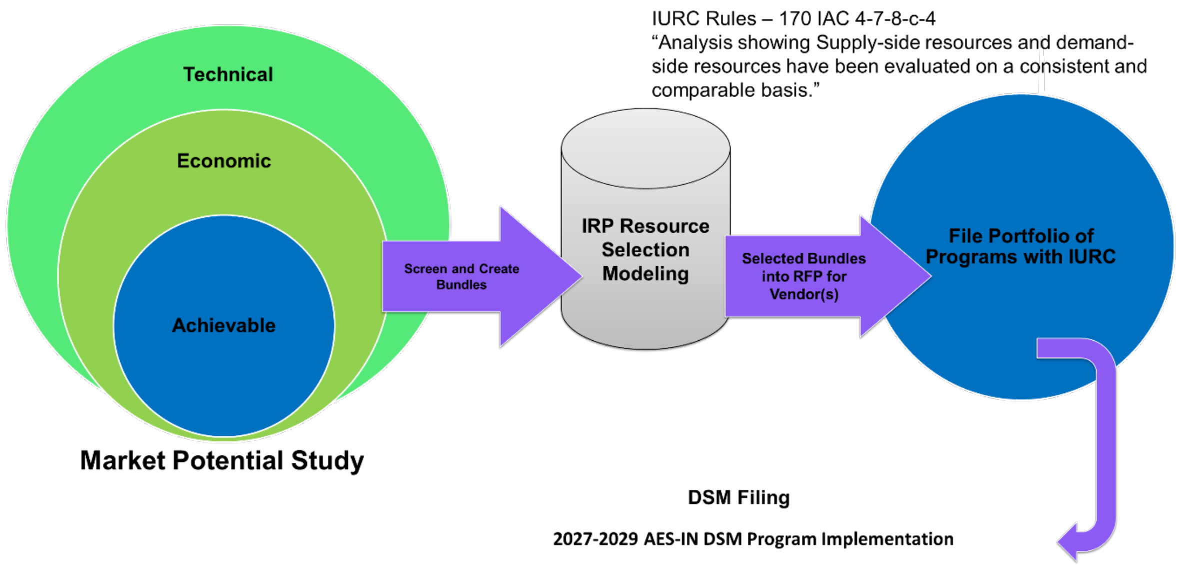
Following the 2025 IRP, the Company expects to continue to propose and deliver additional cost-effective programs consistent with the IURC's IRP and CPCN rules for DSM options. The specific programs to be delivered will be identified and proposed in subsequent AES Indiana's DSM plans to be filed with the IURC.

6.4.3 Demand Side Management Planning Overview

170 IAC 4-7-6(b)(2)(C)

Figure 6-25 below illustrates the stages of AES Indiana's DSM planning process. The objective of this process is to identify AES Indiana's opportunities to provide DSM for the 25-year IRP planning period in a manner that aligns with direction provided by the IURC and that is consistent with the IRP rules. DSM opportunities identified during the IRP process will serve as the starting point for developing a cost-effective DSM Action Plan for consideration and approval by the IURC. AES Indiana's DSM Action Plan will be consistent with Ind. Code § 8-1-8.5-10, which requires public utilities to provide DSM with energy efficiency goals that are: 1) reasonably achievable; 2) consistent with the utility's IRP; and 3) designed to achieve an optimal balance of energy resources in the utility's service territory.

Figure 6-25: Overview of DSM Process



AES Indiana initiated the current DSM planning process by contracting with GDS to complete a DSM market potential study ("MPS') and End-Use Analysis. GDS is an engineering and consulting firm with a practice that includes energy efficiency planning for utilities. The MPS determines an achievable level of DSM in AES Indiana's service territory by estimating customer adoption rates for a comprehensive list of DSM measures. The MPS ensures that the DSM level optimized within the IRP is "reasonably achievable."

Per 170 IAC § 4-7-8(c)(4), demand-side resources should be modeled on a consistent and comparable basis with supply-side resources. To accomplish this, AES Indiana used the Realistic Achievable Potential ("RAP") results from the MPS to create IRP model inputs with a load shape and levelized costs similar to those of a supply-side resource. The RAP results were then divided into 24 selectable "bundles" -9 for energy efficiency and 15 for DR measures. Six income-qualified bundles were predefined in the model and were automatically selected. The bundles include those in Figure 6-26.

Figure 6-26: Energy Efficiency and Demand Response Bundles

Energy Efficiency	
Forced	**Selectable**
IQ_HEAR_V1	CI_V1
IQ_HEAR_V2	CI_V2
IQ_HEAR_V3	CI_V3
IQW_V1	ResBEH_Tier1_V1
IQW_V2	ResBEH_Tier1_V2
IQW_V3	ResBEH_Tier1_V3
	Res_Tier2_V1
	Res_Tier2_V2
	Res_Tier2_V3
Demand Response	
Forced	**Selectable**
DR (Rider 17)[42]	DR AC Switch One Way
DR (Rider 14)[43]	DR AC Switch Two Way
DR (ACLM)_Existing[44]	DR Thermostat
	DR WH
	DR Smart App
	DR Room AC
	DR Lighting
	DR EV
	DR TOU
	DR PTR
	DR BDR
	DR Battery
	DR CI TES
	DR Capacity Bidding
	DR Load Curtailment

The DSM bundles were evaluated alongside supply-side resources in EnCompass. The results help inform the DSM Action Plan for the 2027-2029 period.

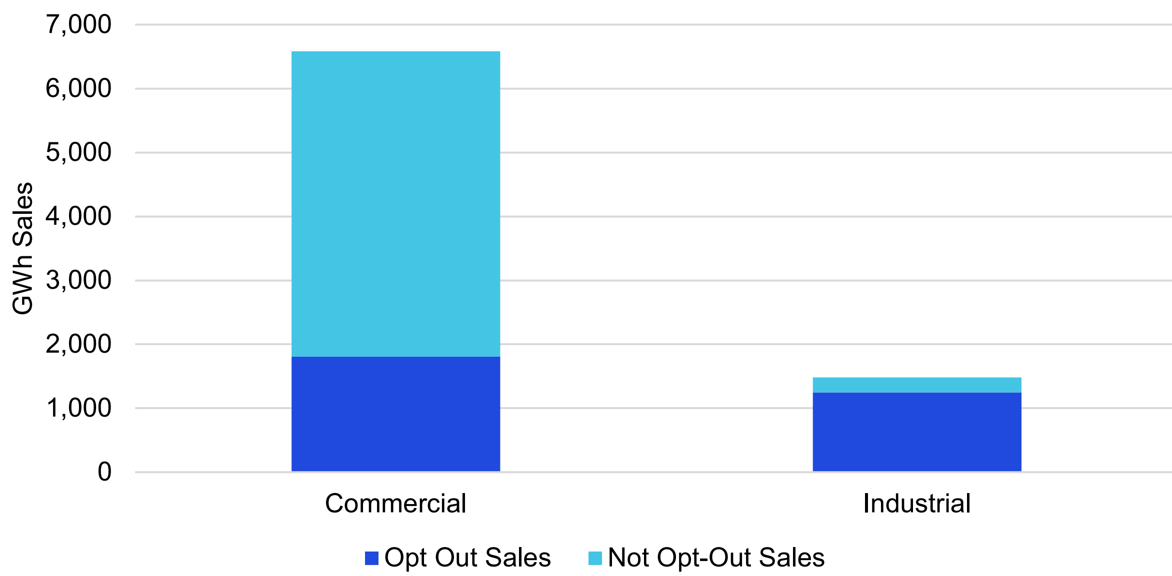
[42] Bundles expire at the end of 2026.
[43] *Id.*
[44] *Id.*

Opt-Out Customers

In Indiana, individual commercial or industrial customer sites with a peak load greater than one MW are eligible to opt out of utility-funded electric energy efficiency programs. As of 2024, approximately 27% of total reclassified retail commercial sales have opted out of utility-funded electric energy efficiency programs, while roughly 84% of total reclassified retail industrial sales have opted out in the AES service territory.

Figure 6-27 below shows total sales for the C&I sectors, as well as sales by sector that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out includes both ineligible load (i.e., does not meet the 1 MW peak demand requirement) and eligible load that has not yet opted out.

Figure 6-27: C&I Customer Opt-Out Compared to Non-Opt-Out Sales



GDS removed the sales from opt-out customers in the assessment of technical, economic, and achievable potential reflected in this report.

DSM Stakeholder Engagement

AES Indiana has maintained a strong collaborative relationship with its stakeholders throughout the MPS and IRP process, making all MPS documents available to stakeholders with nondisclosure agreements. AES stakeholder input began in October of 2024. AES Indiana welcomed stakeholder input into the process and made an effort to incorporate stakeholder ideas into its methodology (e.g., the bundling methodology and Enhanced-RAP described later). Over the past year, AES Indiana has held four technical meetings with stakeholders to share findings and to receive feedback during the MPS process. A list of stakeholder technical meetings dates relevant to AES Indiana's DSM modeling activities is as follows:

- EE MPS Kick Off Meeting – September 10, 2024
- IRP Technical Workshop #1 – January 22, 2025

- IRP Technical Workshop #2 – July 24, 2025
- IRP Technical Workshop #3 – September 3, 2025
- Meeting to discuss Enhanced RAP IRP selections – September 24, 2025
- Between September 2024 and July 2025, AES Indiana hosted bi-weekly meetings with GDS Associates and the AES Indiana DSM Stakeholder group to provide updates on the MPS and solicit feedback on key methodological issues.

6.4.4 Market Potential Study and End Use Analysis

170 IAC 4-7-4(15), 170 IAC 4-7-6(b)(2)(B), and 170 IAC 4-7-6(b)(2)(C)

An MPS is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies. AES Indiana contracted with GDS to conduct this analysis, which began in the fall of 2024.

GDS developed the potential savings estimates by:

1) Creating AES Indiana's market characterization or establishing a forecast of the saturation and efficiency levels of existing equipment used by AES Indiana's customers;

2) Creating the measure characterization or developing a comprehensive list of cost-effective energy efficiency measures; and

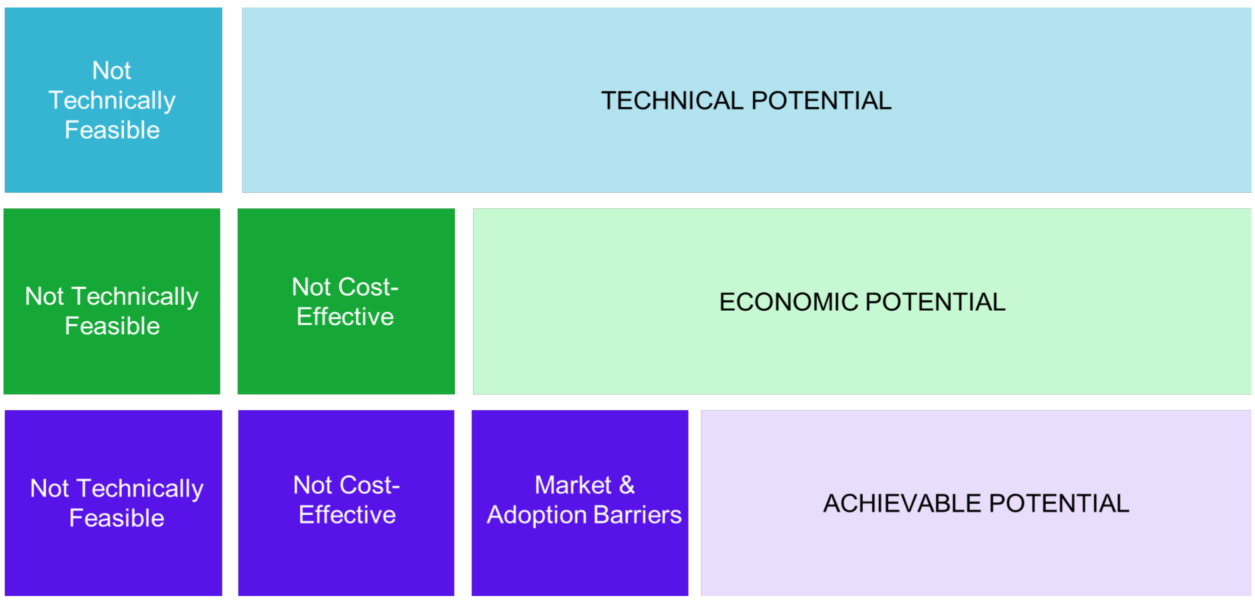
3) Developing potentials or estimating the adoption of the listed energy efficiency measures using the saturation and efficiency forecast as a basis for efficiency uptake.

Through this approach, the Technical, Economic, Maximum Achievable, and Realistic Achievable Potential estimates were developed and are graphically illustrated in Figure 6-59 and defined as follows:

- *Technical Potential* – potential for DSM adoption that assumes no barriers to customer adoption, e.g., financial limitations, customer awareness, and willingness to participate.
- *Economic Potential* – potential for DSM that only includes measures that are deemed to be cost-effective based on a measure-level screening using the Utility Cost Test ("UCT").
- *Achievable Potential* – potential from DSM that assumes certain market and adoption barriers, e.g., incentive levels and barriers to participation. GDS considered two levels of Achievable Potential:
    - *Maximum Achievable Potential ("MAP")* – potential for DSM that assumes paying an incentive equal to 100% of the measure's incremental cost and limited barriers to participation.
- *Realistic Achievable Potential ("RAP")* – is the subset of maximum achievable potential for DSM that assumes the incentives paid for DSM and barriers to participation are aligned with historic levels.

- *Enhanced Achievable Potential ("E-RAP")* – estimates achievable potential by adjusting incentive levels in the RAP scenario to increase participation beyond the RAP scenario, while also considering implications related to cost-effectiveness. This scenario was born from stakeholder feedback and collaboration. The maximum incentive was calculated to either (1) cover a sector-specific lifetime cost per MWh ($35 for non-residential and $50 for residential) or (2) 100% of the measure cost, whichever was less. Further, an incentive floor of 10% of the measure cost was included. Savings and costs are greater than the RAP scenario but less than the MAP scenario.

Figure 6-28: Types of Energy Efficiency Potential



GDS conducted market research that would inform critical elements of the market potential study. Primary market research activities were focused on collecting updated equipment penetration, saturation, and efficiency characteristics; as well as customer Willingness to Participate ("WTP") in the program offerings across selected end-uses and measures. The resulting data were used to update baseline and efficient equipment saturation estimates in the MPS and to develop expected long-term adoption rates of energy efficiency and demand response over the study horizon. The GDS team conducted surveys of business and residential AES Indiana customers from January through March 2025 with the objectives of gathering primary data on the following topics:

→ Willingness to participate in a variety of energy efficiency and demand response program scenarios;

→ Baseline/saturation of energy-using equipment;

→ Program awareness; and

→ Market barriers.

GDS conducted 991 residential and 257 C&I baseline surveys, 423 residential energy efficiency and solar WTP surveys, 416 residential demand response and EV WTP surveys, 88 C&I energy efficiency and solar WTP surveys, and 75 C&I demand response WTP surveys. The full breakdown of the survey sampling targets and responses are summarized in Figure 6-60. These survey results served as inputs for the MPS and enabled GDS to consider the specific market conditions that exist in AES Indiana's service territory.

Figure 6-29: Survey Sampling Targets and Response

Group	Design Confidence & Precision[45]	Sample Frame	Target Responses	Number of Responses[46]	Achieved Precision[47]
Baseline Surveys					
Residential	**95/5**	**15,320**	**384**	**991**	**± 3.1%**
C&I	**90/10**	**7,718**	**68**	**257**	**± 5.1%**
Willingness to Participate Surveys					
Residential – EE & Solar Modules	**95/5**	**7,660**	**384**	**423**	**± 4.0%**
Residential – DR & EV Modules	**95/5**	**7,660**	**384**	**416**	**± 4.0%**
C&I – EE & Solar Modules	**90/10**	**3,718**	**68**	**88**	**± 8.8%**
C&I – DR Modules	**90/10**	**3,718**	**68**	**75**	**± 9.5%**

GDS used this survey data and its subsequent analysis to gather a clear understanding of the current market segments in the AES Indiana service territory. The GDS team coordinated with AES Indiana to gather utility sales and customer data, along with existing market research, to define appropriate market sectors, market segments, vintages, saturation data, and end uses. This information served as the basis for disaggregating a forecast and characterizing the residential and non-residential sectors.

GDS disaggregated the baseline forecast by sector and end-use. The residential forecast was broken out by housing type between existing income-qualified and market-rate customers, as well as new construction. The commercial forecast was disaggregated based on major EIA Commercial Buildings Energy Consumption Survey ("CBECS") business types: retail, warehouse,

[45] Represents % Confidence/% Relative Precision
[46] Represents total number of respondents, although not all respondents answered all questions
[47] Represents precision if every respondent answered a question, precision for each question will vary based on number of responses to that question

food sales, office, lodging, health, food services, education, and miscellaneous. The industrial forecast breakdown was determined by actual load consumption shares and major industry types as defined by EIA's Manufacturing Energy Consumption Survey ("MECS") data. The segmentation analysis was performed by applying territory-specific segment and end-use consumption shares, derived from AES Indiana's customer database and SIC code analysis (i.e., building segmentation), and by EIA CBECS and MECS data (i.e., end-use segmentation) to forecast year sales. Within the residential, commercial, and industrial market segments, the sector-level disaggregated forecasts were further segmented by the major end uses shown in Figure 6-30 below.

Figure 6-30: Major End Uses by Customer Class

Residential	C&I	
Residential	***Commercial***	***Industrial***
Heating	Interior Lighting	Lighting
Cooling	Exterior Lighting	HVAC
Water Heating	Refrigeration	Machine Drive
Cooking	Space Cooling	Process Heat
Refrigerator	Space Heating	Process Cool / Refrigeration
Freezer	Ventilation	Other Process
Dishwasher	Water Heating	Other Facility
Clothes Washer	Plug Loads / Office Equipment	Compressed Air
Dryer	Cooking	Water / Wastewater
Television	Other	Process – Agriculture
Light	Whole Building / Behavioral	Whole Building / Behavior
Miscellaneous	Compressed Air	

Next, GDS developed a comprehensive list of energy efficiency technologies suitable for AES Indiana's market. The sector-level energy efficiency measure lists were informed by a range of sources, including the Illinois Technical Resource Manual, current AES Indiana program offerings, measures included in other recent Indiana utility market potential studies, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with AES Indiana and stakeholders. The final measure list ultimately included in the study reflected the informed comments and considerations of the parties who participated in the measure list review process. The annual and lifetime energy and demand savings associated with decrement bundles are attached to this Report as Attachment 6-2. AES Indiana's MPS, completed by GDS, is attached to this Report as Attachment 6-3.

Achievable Potential Savings: Residential

Figure 6-31 presents the MAP, RAP, and Enhanced RAP across the 19-year study period (2026-2045). The bars on Figure provide the respective incremental annual MAP, RAP, and Enhanced RAP in MWh per year energy savings. The corresponding lines show the cumulative annual MAP, RAP, and Enhanced RAP as percentages of forecasted annual sector sales. The incremental RAP rises from 78,000 MWh to 119,000 MWh or more. The Enhanced RAP start is 89,000 MWh and rises to more than 135,000 MWh, corresponding to 16.0% and 18.5% cumulative annual savings for RAP and Enhanced RAP, respectively.

Figure 6-31: Residential Annual Achievable Potential

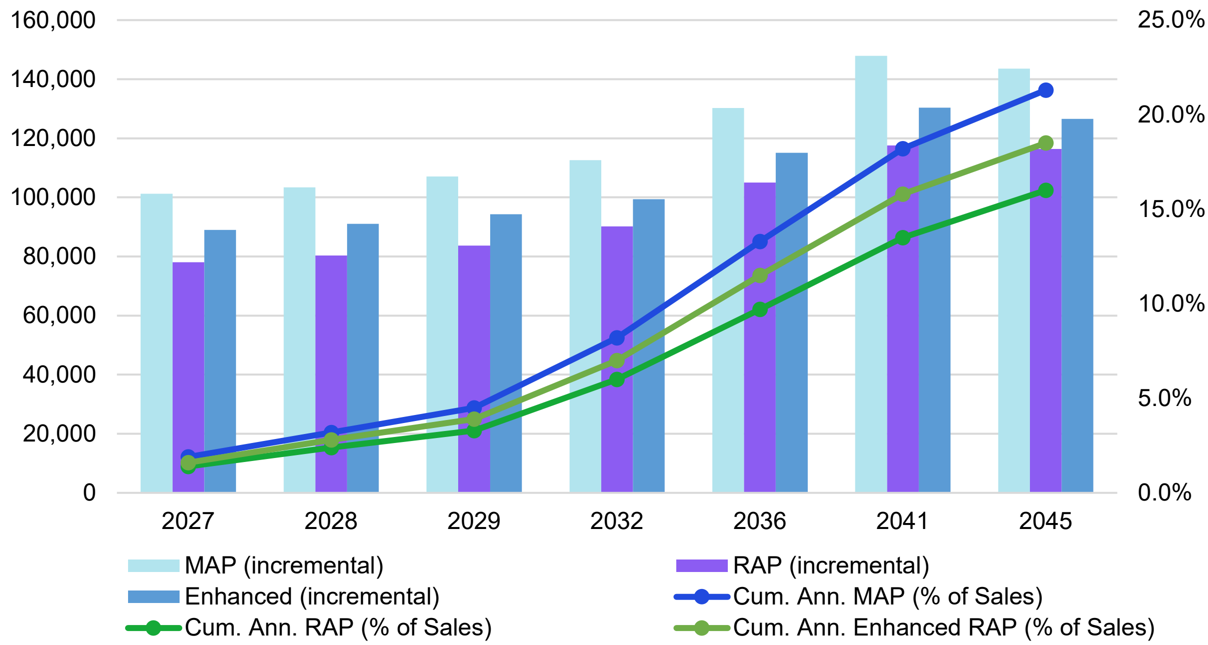


Figure 6-32 below shows the incremental and cumulative annual residential sector energy and demand savings for MAP and RAP across the next three years, as well as over the 10-year and 19-year time horizons. Incremental RAP energy savings begin at roughly 78,000 MWh in 2024, then increase over the next several years. Cumulative RAP energy savings rise to approximately 1.0 million MWh by 2045.

Figure 6-32: Incremental and Cumulative Annual *Residential* Sector MAP and RAP Energy and Demand Savings

	2027	2028	2029	2036	2045
Incremental Annual Energy (MWh)					
MAP	101,187	103,349	107,084	130,214	143,629
RAP	78,099	80,291	83,673	105,037	116,352
Enhanced RAP	89,032	91,017	94,281	115,142	126,616
Incremental Annual Energy (MW)					
MAP	21.5	21.9	22.2	25.1	26.2
RAP	15.4	15.6	15.9	18.3	19.5
Enhanced RAP	17.9	18.0	18.1	19.9	21.1
Cumulative Annual Energy (MWh)					
MAP	101,187	174,628	247,349	759,152	1,284,386
RAP	78,099	128,935	179,785	555,381	968,945
Enhanced RAP	89,032	150,764	212,217	654,635	1,120,521
Cumulative Annual Energy (MW)					
MAP	21.5	39.9	57.8	169.8	255.9
RAP	15.4	27.5	39.5	116.4	181.2
Enhanced RAP	17.9	32.4	46.6	134.4	205.6

Achievable Potential Savings: Commercial and Industrial

Figure 6-33 presents the MAP, RAP, and Enhanced RAP over the 19-year study period. The bars show the respective incremental annual MAP, RAP, and Enhanced RAP in MWh of energy savings per year. The corresponding lines show the cumulative annual MAP, RAP, and Enhanced RAP as percentages of forecasted annual sector sales. The incremental RAP ranges from 52,000 to 79,000 MWh. The Enhanced RAP ranges from 54,000 to 89,000 MWh, with corresponding cumulative annual savings of 15.6% and 16.8% for RAP and Enhanced RAP, respectively.

Figure 6-33: C&I Annual Achievable Potential

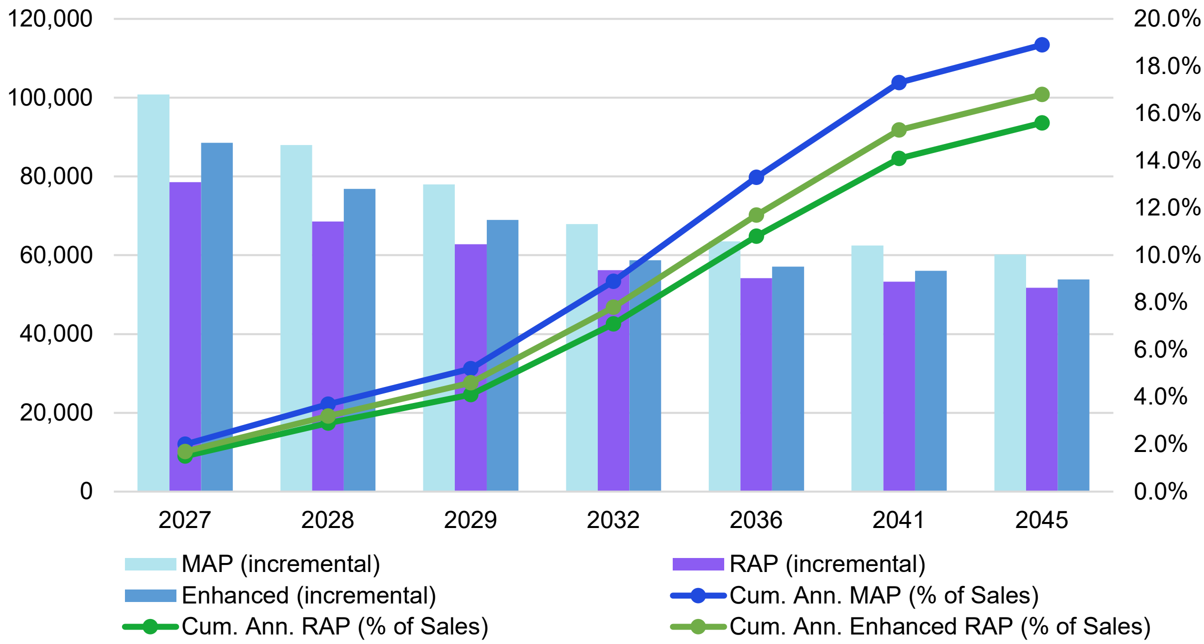


Figure 6-34 below provides the incremental and cumulative annual C&I sector energy and demand savings for MAP, RAP, and Enhanced RAP over the next three years, 10-year, and 19-year time horizons. Incremental RAP energy savings begin at roughly 78,600 MWh in 2027, then decrease steadily over the next several years. Cumulative RAP energy savings rise to approximately 830,000 MWh by 2045.

Figure 6-34: Incremental and Cumulative Annual *C&I* Sector MAP and RAP Energy and Demand Savings

	2027	2028	2029	2036	2045
Incremental Annual Energy (MWh)					
MAP	100,795	87,961	77,973	63,500	60,230
RAP	78,571	68,547	62,776	54,194	51,710
Enhanced RAP	88,534	76,827	68,947	57,089	53,867
Incremental Annual Energy (MW)					
MAP	18.5	15.8	13.4	11.4	17.0
RAP	14.0	11.9	10.6	9.6	14.3
Enhanced RAP	16.0	13.6	11.7	10.1	14.9
Cumulative Annual Energy (MWh)					
MAP	100,795	188,756	266,293	694,259	1,007,362
RAP	78,571	147,119	209,456	560,081	829,043
Enhanced RAP	88,534	165,361	233,896	611,027	892,745
Cumulative Annual Energy (MW)					
MAP	18.5	34.3	47.6	119.3	176.1
RAP	14.0	26.0	36.5	119.3	176.1
Enhanced RAP	16.0	29.6	41.2	119.3	176.1

Demand Response

Figure 6-35 and Figure 6-36 below show the MAP and RAP for years one through three, 10, and 19. MAP is defined as the maximum participation that would occur under realistic assumptions, and RAP further considers additional barriers to program implementation and participation that would be expected to occur.

Some of the values in Figure 6-35 and Figure 6-36 are marked with an asterisk. These are not MAP or RAP. However, the IRP modeled them to test additional DR potential.

Figure 6-35: Demand Response MAP

Sector	Program	2027	2028	2029	2036	2045
Residential	DLC Central AC Switch - One Way	19	18	18	15	11
	DLC Central AC Switch - Two Way	3	3	3	2	2
	DLC Thermostat (Free Thermostat)	2	2	2	3	4
	DLC Thermostat (BYOT)	49	52	56	76	95
	DLC Water Heater Switch*	1	1	2	3	5
	DLC Grid-Enabled Water Heater*	1	4	8	11	10
	DLC Smart Appliances*	0	0	1	1	1
	DLC Room Air Conditioning*	0	1	3	3	3
	DLC Electric Vehicle*	0	0	0	3	9
	Electric Vehicle Time of Use Incentive*	0	1	1	6	18
	Electric Vehicle EVX Rate*	0	0	0	0	0
	Time of Use Rate	0	0	3	24	20
	Peak Time Rebate	0	0	3	19	16
	Behavioral Demand Response	0	0	22	13	11
	Battery Storage*	0	0	1	5	6
	Sector Total	**76**	**84**	**122**	**185**	**211**
C&I	DLC Central AC Switch - One Way*	0	0	0	0	0
	DLC Central AC Switch - Two Way	2	2	3	8	14
	DLC Thermostat (Free Thermostat)	1	2	4	6	6
	DLC Thermostat (BYOT)	1	1	2	4	6
	DLC Water Heater Switch	1	3	6	8	8
	DLC Grid-Enabled Water Heater	1	2	4	6	5
	DLC Lighting*	0	0	1	8	14
	DLC Electric Vehicle*	0	0	0	0	0
	Electric Vehicle Time of Use Incentive*	0	0	0	0	0
	Time of Use Rate	0	0	1	8	7
	Thermal Energy Storage Rate*	0	0	0	0	0
	Battery Storage*	0	0	0	0	1
	Capacity Bidding	10	31	62	78	62
	Load Curtailment	11	36	76	107	97
	Sector Total	**26**	**78**	**159**	**233**	**220**
Residential and C&I Total		**102**	**162**	**281**	**418**	**432**

Figure 6-36: Demand Response RAP

Sector	Program	2027	2028	2029	2036	2045
Residential	DLC Central AC Switch - One Way	19	19	18	16	13
	DLC Central AC Switch - Two Way	3	3	3	2	2
	DLC Thermostat (Free Thermostat)	2	2	2	2	2
	DLC Thermostat (BYOT)	46	47	48	53	57
	DLC Water Heater Switch*	1	1	1	3	4
	DLC Grid-Enabled Water Heater*	0	1	2	3	2
	DLC Smart Appliances*	0	0	0	0	0
	DLC Room Air Conditioning*	0	1	1	2	2
	DLC Electric Vehicle*	0	0	0	3	8
	Electric Vehicle Time of Use Incentive*	0	0	1	4	13
	Electric Vehicle EVX Rate	0	0	0	0	0
	Time of Use Rate	0	0	1	12	12
	Peak Time Rebate	0	0	2	17	16
	Behavioral Demand Response	0	0	23	19	18
	Battery Storage*	0	0	1	4	6
	Sector Total	**72**	**74**	**104**	**140**	**156**
C&I	DLC Central AC Switch - One Way*	0	0	0	0	0
	DLC Central AC Switch - Two Way	1	2	2	5	8
	DLC Thermostat (Free Thermostat)	0	1	3	4	4
	DLC Thermostat (BYOT)	1	1	1	3	4
	DLC Water Heater Switch	1	2	5	7	6
	DLC Grid-Enabled Water Heater	0	0	1	1	1
	DLC Lighting*	0	0	1	6	11
	DLC Electric Vehicle*	0	0	0	0	0
	Electric Vehicle Time of Use Incentive*	0	0	0	0	0
	Time of Use Rate	0	0	1	7	6
	Thermal Energy Storage Rate*	0	0	0	0	0
	Battery Storage*	0	0	0	0	1
	Capacity Bidding*	8	24	48	65	58
	Load Curtailment	9	28	58	83	77
	Sector Total	**20**	**59**	**120**	**180**	**177**
Residential and C&I Total		**92**	**133**	**224**	**320**	**333**

Industrial Electrification

Despite challenging energy economics, the industrial sector, nationally, has exhibited some adoptions of electrification. The industrial sector differs from the residential and commercial sectors due to specialized process equipment that may consume considerable amounts of natural gas, with performance needs that vary by manufacturing process. For example, using industrial heat pumps to provide low-grade process heat will yield substantially different outcomes than replacing a gas steam boiler with an arc boiler powered by electricity. The specific timing and type of technology to be adopted are highly uncertain, particularly within a specific utility service territory. Corporate decisions will be based on energy economics, potential decarbonization goals, the timing of replacing aging process equipment, and overall business strategies.

GDS utilized data from NREL's Electrification Futures Study to estimate the possible impact of electrification growth in AES' industrial sector. The NREL study provides national-level estimates of industrial electrification, with NREL's reference case indicating zero industrial electrification. NREL's low and medium cases envision nearly zero industrial adoptions of electrification, in terms of the growth in electricity sales for the industrial sector. Only in NREL's high case does industrial electrification exhibit meaningful growth.

GDS began with AES' forecast of industrial sales across the forecast period. GDS notes that industrial electricity sales are approximately 15 percent of AES' total electricity sales, indicating that the industrial sector makes up a relatively small portion of AES' customer base, further suggesting caution in making assumptions for industrial electrification impacts for a specific service territory. To estimate the impact of NREL's high case for industrial electrification, GDS analyzed the NREL assumption regarding overall industrial load growth and removed the share of load growth already accounted for in AES' forecast. The remaining share was assumed to be driven by electrification. The growth occurs in the last decade of the forecast.

To model the adoption of industrial electrification and the resulting increase in electricity sales above the current forecast, GDS applied a compound annual growth rate that captures the entire period's growth in industrial electrification.

Three scenarios were developed to estimate the load impacts:

→ A high scenario that utilizes NREL's high case

→ A medium scenario that assumes 50% the growth of the high case

→ A low scenario that assumes 25% the growth of the high case

These three scenarios can be compared to NREL's reference case, which serves as a "Business As Usual" ("BAU") scenario. With NREL's reference case indicating that no industrial electrification would occur, the BAU case inherently reflects that AES' industrial sector would not adopt electrification technologies.

6.4.5 Demand Side Management Bundles in Model

For EnCompass to evaluate DSM on a consistent and comparable basis with supply-side resources, the DSM potential, defined by the MPS, needed to be disaggregated into smaller bundles with supply-side characteristics that act as model inputs. AES Indiana worked closely with GDS and its stakeholders to formulate an approach to DSM bundling that addressed stakeholder requests, met IURC rules, and aligned with the model requirements.

AES Indiana used the realistic, achievable potential identified in the MPS as the starting point for developing energy-efficiency bundles to be modeled in the IRP. GDS provided energy-efficiency IRP inputs across three sectors (residential, income-qualified, and C&I). The residential and C&I bundles were modeled as selectable resources in the IRP capacity expansion model. The income-qualified bundle was treated as a 'going-in' resource, as the high costs of program delivery would likely prevent its selection in the IRP, and AES Indiana anticipates continuing to offer energy efficiency programs to its income-qualified customers despite these limitations in cost-effectiveness.

In addition to sector segmentation, the three vintage bundles (2027-2029, 2030-2032, and 2033-2045) enable the model to optimize the value of energy efficiency across different time periods. The first vintage (2027-2029) aligns with AES Indiana's next DSM program planning period. Based on stakeholder feedback and a review of initial cost and savings inputs, GDS further segmented residential sector savings into high-cost measures (Tier 2) and low- and mid-cost measures (Tier 1, including behavioral measures) for each vintage. Further, GDS included a bundle representing RAP savings attributed to measures installed in the AES Indiana territory, driven by the Indiana Office of Energy Development and the *Indiana Energy Saver Program* (IQ HEAR).[48] Ultimately, five separate bundles were formed for energy efficiency.

Three selectable bundles:

- → Residential Tier 1 plus Residential Behavior
- → Residential Tier 2
- → Commercial and Industrial

Two going-in bundles:

- → Income-qualified Weatherization
- → Income Qualified, Indiana Home Appliance Rebate (IQ HEAR)

The second and third time-vintages (2030-2032 and 2033-2045) were modeled the same way as the first vintage (five total bundles, three selectable, and two going-in). Figure 6-37 below shows how resources were included in each vintage bundle.

[48] The Indiana Office of Energy Development announced the launch of the Indiana Energy Saver Program on May 14th, 2025. The Indiana Energy Saver Program will provide cost savings through two program offerings: the Home Efficiency Rebates (HOMES) and the Home Appliance Rebates (HEAR). Both offerings are provided through a single application process to maximize the benefits to Hoosier households. Participants will receive the rebate as an upfront discount on the product and installation by a qualified contractor. Learn more and apply at www.IndianaEnergySaver.com.

Figure 6-37: Bundles by Vintage

Vintage 1 (2027-2029)	Vintage 2 (2030-2032)	Vintage 3 (2033-2045)
1. Residential Tier 1 (Low/Medium Cost	1. Residential Tier 1 (Low/Medium Cost	1. Residential Tier 1 (Low/Medium Cost
2. Residential Tier 2 (High-Cost Measures)	2. Residential Tier 2 (High-Cost Measures)	2. Residential Tier 2 (High-Cost Measures)
3. C&I Sector	3. C&I Sector	3. C&I Sector
4. Income-Qualified Weatherization	4. Income-Qualified Weatherization	4. Income-Qualified Weatherization
5. IQ HEAR	5. IQ HEAR	5. IQ HEAR

In addition, two adjustments to the MPS realistic achievable energy efficiency potential savings and one direct adjustment to costs were necessary prior to inclusion in AES Indiana's IRP analysis. The first adjustment converted the energy efficiency achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of AES Indiana's programs. Net savings were calculated by applying AES Indiana's most current net-to-gross ratios from evaluations of the AES Indiana DSM Portfolio to the MPS estimates of gross achievable savings.

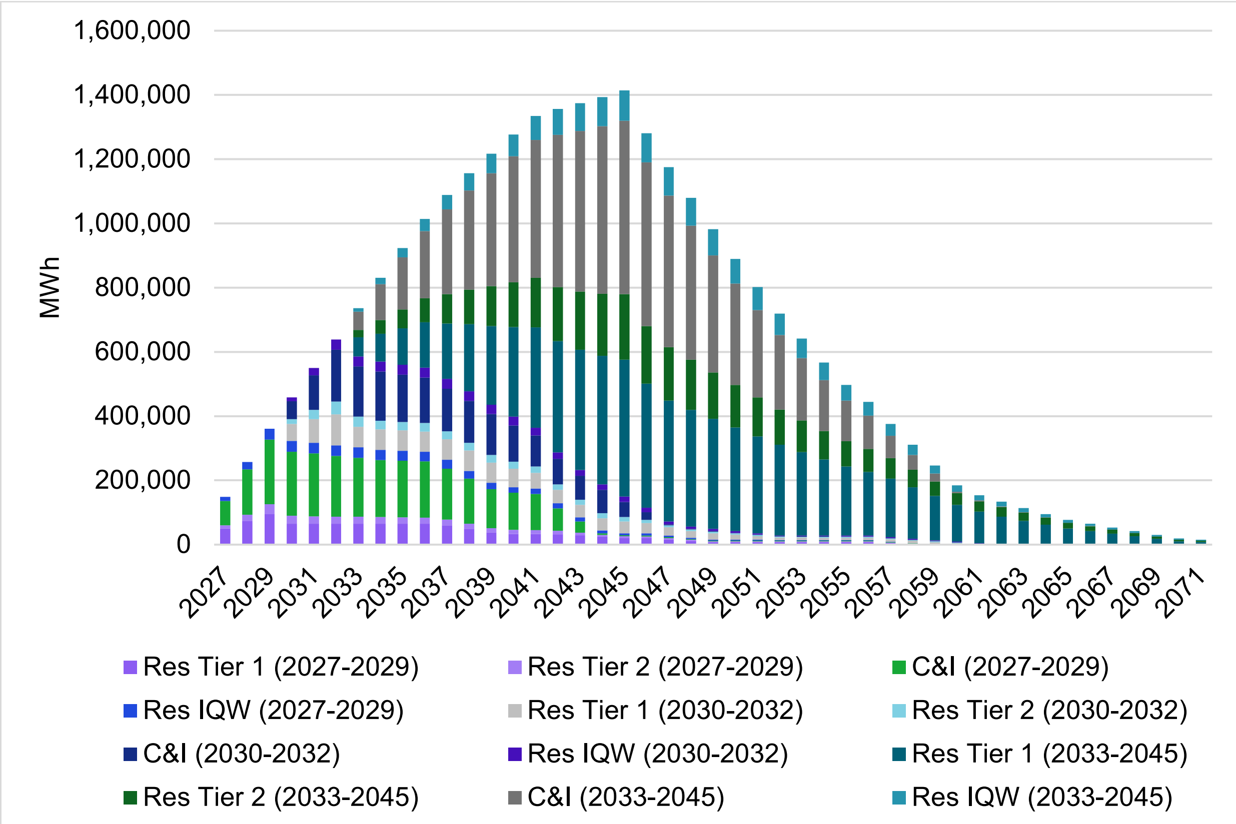
Due to small annual differences in the mix of energy efficiency measures included in the realistic achievable scenario and associated net-to-gross ratios, the energy efficiency impacts modeled in the IRP ranged from 92% to 93% of the gross realistic achievable potential identified in the MPS across the 2027-2045 timeframe.

The second savings adjustment was to provide measure potential savings at the generator-level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on Company line losses to convert savings from the meter-level up to the generator-level.

On the cost side, because EnCompass does not calculate the avoided T&D benefits associated with DSM measures, GDS provided AES Indiana with energy efficiency bundle costs that have been adjusted to net out the avoided NPV lifetime T&D benefit based on the project MW savings of the respective vintage-based bundles.

The energy efficiency impacts provided to AES Indiana for IRP modeling, by vintage block, are summarized in Figure 6-38. Additional annual detail are provided in Attachment 6-3. As shown in the tables provided in Attachment 6-3, the impacts for each vintage block provide cumulative annual lifetime savings. Conversely, because energy efficiency program costs only occur during the year of measure installation, budgets align more directly with the specified vintage timeframes.

Figure 6-38: Summary of Energy Efficiency IRP Bundle Savings



In addition to the annual impacts shown in Figure 6-38, hourly (or 8,760) shapes that reflect the various measures and end-use mix reflected in each energy efficiency resource bundle were provided to AES Indiana to permit EnCompass to assess the value of energy savings on an hourly basis. These 8,760 shapes were based on residential and commercial end-use load shapes for Indiana from NREL's End-Use Load Profiles database. The ultimate 8,760 shapes are unique for each sector and vintage bundle.

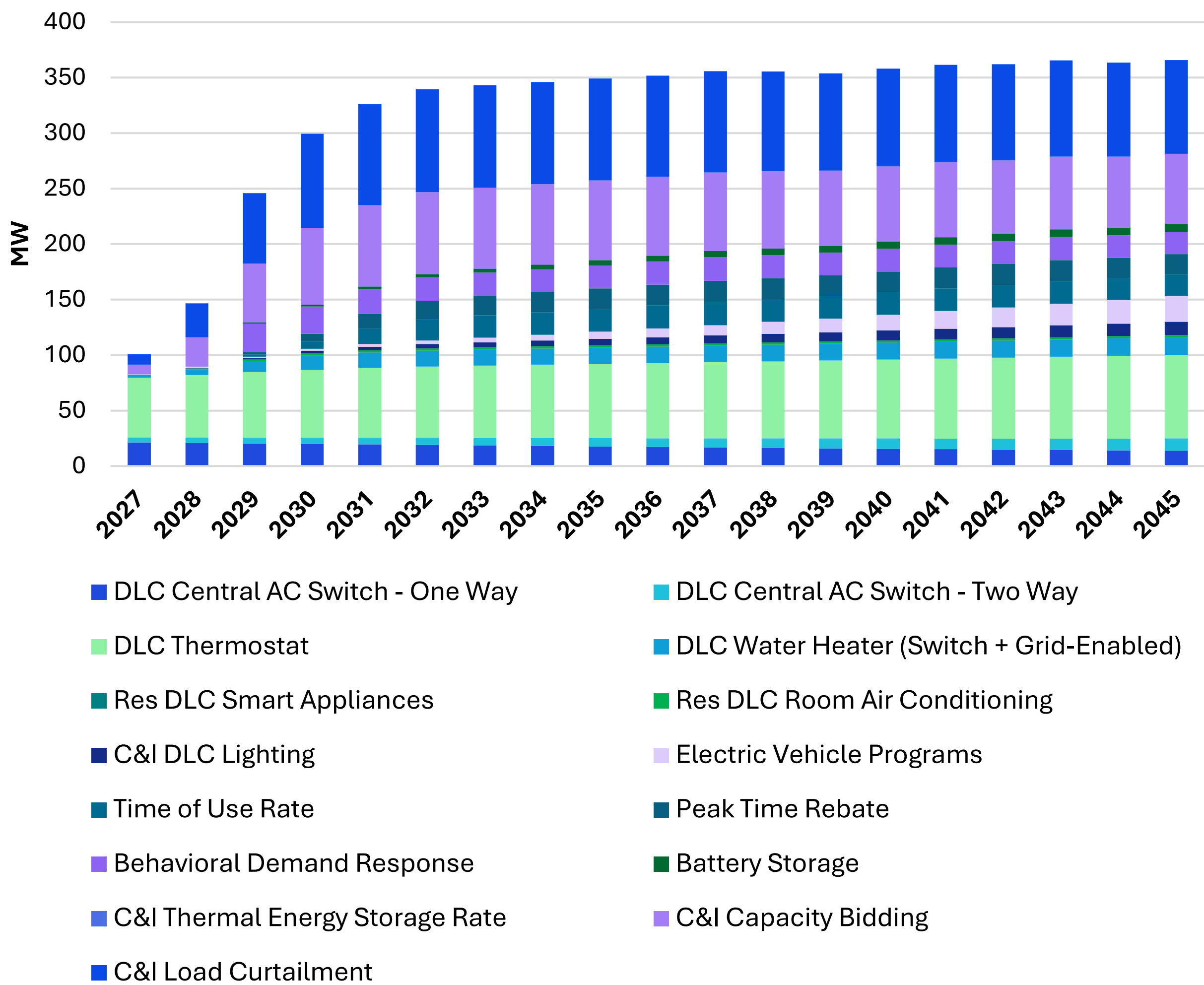
In the IRP modeling, AES Indiana also considered demand response alongside other supply resources to supply capacity needs. Levels of demand potential associated with the realistic achievable potential scenario from the MPS were provided as inputs to EnCompass. Demand response savings were divided into four bundles based on sector and resource type (i.e., direct load control or demand response rates). Figure 6-70 provides the demand response inputs used in the IRP modeling.

Figure 6-39: Demand Response Inputs Used in the IRP Modeling

Bundles	Programs Included
DLC Central AC Switch - One Way	Residential DLC Central AC Switch - One Way; C&I DLC Central AC Switch - One Way
DLC Central AC Switch - Two Way	Residential DLC Central AC Switch - Two Way; C&I DLC Central AC Switch - Two Way
DLC Thermostat	Residential DLC Thermostat (Free Thermostat); C&I DLC Thermostat (Free Thermostat); Residential DLC Thermostat (BYOT); C&I DLC Thermostat (BYOT)
DLC Water Heater (Switch + Grid-Enabled)	Residential DLC Water Heater Switch; C&I DLC Water Heater Switch; Residential DLC Grid-Enabled Water Heater; C&I DLC Grid-Enabled Water Heater
Res DLC Smart Appliances	Residential DLC Smart Appliances
Res DLC Room Air Conditioning	Residential DLC Room Air Conditioning
C&I DLC Lighting	C&I DLC Lighting
Electric Vehicle Programs	Residential DLC Electric Vehicle; Residential Electric Vehicle Time of Use Incentive; Residential Electric Vehicle EVX Rate; C&I DLC Electric Vehicle; C&I Electric Vehicle Time of Use Incentive
Time of Use Rate	Residential Time of Use Rate; C&I Time of Use Rate
Peak Time Rebate	Residential Peak Time Rebate
Behavioral Demand Response	Residential Behavioral Demand Response
Battery Storage	Residential Battery Storage; C&I Battery Storage
C&I Thermal Energy Storage Rate	Thermal Energy Storage Rate
C&I Capacity Bidding	C&I Capacity Bidding
C&I Load Curtailment	C&I Load Curtailment

Summer demand impacts (in MW) are shown, but select DR programs provide opportunities for capacity savings in other seasons, and these impacts were considered in EnCompass. In general, the analysis assumed that demand response programs are net neutral with regard to annual energy (MWh) impacts. As with the energy inputs, the costs were adjusted to represent program costs less the avoided NPV lifetime T&D benefit from the programs. Due to the annual accrual of savings and costs for DR programs, it was not necessary to develop distinct vintage bundles of DR. However, the IRP model did assess DR over the same three defined time periods as the energy efficiency input bundles. Annual demand response savings and costs, by bundle, are provided in Attachment 6-3. Figure 6-40 provides the annual demand response savings by bundle.

Figure 6-40: Annual Demand Response Savings by Bundle



Demand response was given a 70% capacity accreditation in the MISO markets. MISO is changing market rules, and many factors influence demand response accreditation. AES Indiana will closely monitor this issue, and engage with stakeholders on implications.

6.4.6 Avoided Cost Calculation

170 IAC 4-7-4(29) and 170 IAC 4-7-6(b)(2)(B)

To screen DSM measures for cost effectiveness in the MPS analysis, GDS used avoided energy, capacity, and T&D costs to monetize savings associated with the measures. AES Indiana provided GDS avoided cost assumptions as part of an initial data request. As detailed further below, the avoided cost values for energy and capacity are sourced from the Fall 2024 Fundamental Forecast produced by ACES and are intended to align with the commodity assumptions used in the IRP modeling.

AES Indiana provided GDS with annual on- and off-peak avoided energy costs from the Fall 2024 Fundamental Forecast produced by ACES. GDS used this data to create 8,760 hourly avoided cost values for each forecast year. GDS then applied these avoided costs to the 8,760 savings from each measure based on assigned end-use load shapes[49] to determine the value of measures that save more energy during peak periods than those that might save during off-peak periods. In addition, GDS used avoided capacity cost from the 2024 Fall Fundamental Forecast produced by ACES and T&D avoided costs to estimate coincident peak demand savings for each measure. T&D avoided costs were adopted from the 2022 IRP and scaled by inflation.

6.5 Rate Design

170 IAC 4-7-4(16) and 170 IAC 4-7-6(b)(1)

As the energy landscape continues to evolve with the growing adoption of distributed energy resources (DERs), electric vehicles (EVs), and broader electrification, uncertainty around electricity supply and demand is increasing. Rate design could be a vital instrument in resource planning. It could enable utilities to influence when and how electricity is consumed.

In the 2025 IRP, TOU was a selectable DR Program. TOU rates are a type of pricing structure where the cost of electricity varies depending on the time of day. Prices are higher during the on-peak hours and lower during off-peak hours. This type of rate encourages customers to shift their load to off-peak hours due to the lower cost. This in turn helps flatten the demand curve. The number of peak hours per day can vary, but for the purposes of this study, it was assumed that there would be four on-peak hours per weekday, year-round.

Participation rates were derived from the market research completed for AES. The steady-state participation rates are shown in the table below. All AES customers are eligible to participate in a TOU rate. However, participants already assumed to be participating in a direct load control program (residential and C&I) or load curtailment program (C&I only) were removed from the eligible participant population. This was done to avoid double counting of savings for programs that target similar end uses. The number of participants for the potential study is calculated by multiplying the participation rate by the total eligible customers for each year.

Figure 6-41: Steady-State Participation Rate by Sector for MAP and RAP

Steady-State Participation Rate	MAP	RAP
Residential	28.7%	13%
C&I	42%	25%

Load reduction per participant is shown in the table below. Detailed sources can be found in the report.

[49] End-use load shapes were derived from building energy simulation models created by housing type and building type, specific to the AES Indiana service territory.

Figure 6-42: Per Participant Load Reduction by Sector for Summer and Winter

Per Participant Load Reduction	Summer	Winter
Residential	8.6% of peak load	3.6% of peak load
C&I	2% of peak load	1% of peak

AES Indiana considers and reviews rate design options, which include appropriate cost of service, recovery mechanisms, and encompass innovative approaches. Through its current energy efficiency programs, demand response programs, managed EV charging programs, Rate CGS, curtailable energy riders, and load displacement rider, AES Indiana employs a range of rate options.

Section 7: Environmental Considerations

170 IAC 4-7-4(23) and 170 IAC 4-7-6(a)(4)

7.1 Environmental Overview

Environmental regulations significantly affect AES Indiana's resource planning efforts due to their dynamic and, in many cases, uncertain nature. The majority of these regulations are promulgated by EPA and enforced by EPA or the Indiana Department of Environmental Management ("IDEM"). AES Indiana stays informed of proposed and final rules and determines their effects on Company assets and customer impacts. The most significant changes in recent history focus on fossil fuel-fired plants. This section of the IRP focuses on compliance aspects of environmental regulations.

The most relevant recent activities related to environmental regulations include the following:

- → Revisions and actions related to EPA's finalized 2015 regulations for Coal Combustion Residuals ("CCR") regulating CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA").
- → On June 5, 2023, EPA published a final Federal Implementation Plan ("FIP") to address "good neighbor" obligations related to the 2015 ozone National Ambient Air Quality Standard ("NAAQS"). On June 27, 2024, the U.S. Supreme Court issued an order granting a stay of the FIP.
- → On May 9, 2024, EPA published the final New Source Performance Standards ("NSPSs") for Greenhouse Gases ("GHGs") new and existing sources. On June 17, 2025, EPA published a proposed rule to repeal the May 9, 2024 final rules for new and existing electric generating units ("EGUs") in addition to 2015 greenhouse gas new source performance standards for certain new EGUs.

Some of these rules could require future investments. Planning for compliance with environmental regulations can be complicated due to uncertainty surrounding the final outcome of the regulations and their impacts, including timing as well as current and potential legal and legislative activity.

These types of uncertainties and environmental regulations are incorporated into AES Indiana's IRP process and discussed in detail later in this section following a review of the existing environmental rules and regulations.

7.2 Existing Environmental Regulations

Existing environmental regulations associated with air emissions, water, and wastes that impact AES Indiana's resources are described below.

7.2.1 Air Emissions

170 IAC 4-7-4(21)

EPA issued the Cross State Air Pollution Rule ("CSAPR") in July 2011. CSAPR became effective on January 1, 2015. Phase II of CSAPR became effective on January 1, 2017. AES Indiana meets CSAPR requirements through the operation of its existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and AES Indiana plans to continue to comply with Phase II of CSAPR using these measures.

Additional SO2 requirements and compliance plans are discussed below under NAAQS.

Oxides of Nitrogen ("NOx")

In order to meet more stringent NOx emission reduction requirements, which became effective in 2004 related to the NOx State Implementation Plan ("SIP") Call, AES Indiana installed Selective Catalytic Reduction ("SCR") equipment on Petersburg Generating Station Unit 3 and HSS Unit 7 along with several low NOx Clean Coal Technology ("CCT") projects on other units. The Petersburg SCR unit commenced operations in May 2004, whereas the HSS Unit 7 SCR came online in May 2005.

On September 7, 2016, EPA finalized the CSAPR Update Rule, which established NOx reductions during ozone season for 22 states, including Indiana, to address downwind attainment with the 2008 Ozone NAAQS of 75 parts per billion ("ppb"). Following legal challenges related to the CSAPR Update Rule, on April 30, 2021, EPA issued the Revised CSAPR Update Rule, which required Electric Generating Units ("EGU") in certain states, including Indiana, to participate in a new trading program. These affected EGUs received fewer ozone season NOx allowances beginning in 2021.

On June 5, 2023, the EPA published a final Federal Implementation Plan ("FIP") to address air quality impacts with respect to the 2015 Ozone NAAQS. The rule established a revised CSAPR NOx Ozone Season Group 3 trading program for 22 states, including Indiana, and became effective during 2023. On June 27, 2024, the U.S. Supreme Court issued an order granting a stay of EPA's 2023 FIP pending resolution of legal challenges to the FIP. On November 6, 2024, EPA published an Interim Final Rule in response to the stay. The Interim Final Rule stayed the effectiveness of the Good Neighbor FIP and revised the CSAPR regulations to continue application of the states' prior respective trading programs. At this time, it is uncertain whether future revisions to CSAPR could further impact AES Indiana's NOx emissions limits.

AES Indiana currently meets requirements for NOx through the operation of existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and currently plans to continue to comply using these measures.

Regional Haze

EPA's 1999 Regional Haze Rule established timelines for states to improve visibility in national parks and wilderness areas by establishing reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064 through submittal of a series of State Implementation Plans ("SIP"). Indiana's SIP for the first planning period (through 2018) did not require any additional controls to be installed or operated on AES Indiana's generating facilities. For all future SIP planning periods, states must evaluate whether additional emissions reduction measures may be needed to continue making reasonable progress toward natural visibility conditions. On December 30, 2021, IDEM submitted the Draft Indiana Regional Haze SIP for the Second Implementation period to EPA. The draft SIP does not include additional requirements for AES Indiana EGUs or other EGUs in Indiana. On June 18, 2025, EPA proposed to approve the Indiana SIP. However, it remains uncertain whether the final outcome of a revised Regional Haze SIP could result in more stringent emissions limitations for AES Indiana.

Mercury and Air Toxics Standard ("MATS")

In February 2012, EPA issued the final MATS Rule, which placed stringent emission limits on Hazardous Air Pollutants ("HAPs"), as defined in Section 112 of the CAA.

AES Indiana developed a MATS Compliance Plan, which included activated carbon injection and sorbent injection for mercury control and upgraded FGDs for acid gas control on all coal-fired units. The Plan also included upgraded electrostatic precipitators on Petersburg Unit 4, and Harding Street Unit 7, in addition to baghouses on Petersburg Unit 3 for particulate and mercury control. In development of AES Indiana's MATS Compliance Plan, it also was determined that installation of the necessary controls was not economical for the smaller, less controlled units, Eagle Valley Units 3-6, and Harding Street Units 5 and 6.

AES Indiana received IURC approval in IURC Cause No. 44242 to proceed with its MATS Compliance Plans, and the construction of controls at Petersburg was completed. However, it was later determined when considering new National Pollutant Discharge Elimination System ("NPDES") requirements and other potential future environmental regulations for HSS Unit 7 that the MATS controls were no longer the reasonable least cost solution. AES Indiana received IURC approval in Cause No. 44540 to convert HSS Unit 7 from coal to natural gas instead of pursuing the previously approved retrofit. See below for more detail on NPDES requirements.

On May 7, 2024, EPA published a final rule to revise MATS for coal and oil-fired EGUs which lowered certain emissions limits and revised certain other aspects of MATS.[50] The requirements of MATS will not apply to AES Indiana upon repowering the remaining two coal-fired units at Petersburg (Unit 3 and Unit 4) to natural gas. The repowering of these units is planned to occur in 2026 prior to the compliance data of the MATS revisions (July 2027).

National Ambient Air Quality Standards

EPA is required under the CAA to set NAAQS for air pollutants that endanger public health or welfare. There are several NAAQS, but typically three directly impact fossil-fuel fired power plants:

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[50] On June 17, 2025, EPA proposed a rule to repeal the majority of the May 7, 2024 revisions to MATS.

SO2, ozone, and particulate. NAAQS do not directly limit emissions from utilities, but states must develop SIPs to achieve emissions reductions to address each NAAQS when an area is designated as nonattainment. EPA reviews NAAQS and the science on which they are based on a five-year basis. This review process includes gathering input from the scientific community and the public, an integrated science assessment, a risk and exposure assessment, and a policy assessment.

On June 22, 2010, EPA revised the NAAQS for SO2 from 140 ppb on a 24-hour basis to 75 ppb on a one-hour basis. The areas in which Harding Street, Eagle Valley, and Petersburg operated were designated as nonattainment with the lowered standard. As a result, IDEM developed a SIP to address the 2010 SO2 NAAQS, and on September 30, 2015, published revisions to 326 IAC § 7-4-15 establishing new and more stringent emission limits for Petersburg coal-fired units with compliance required by January 1, 2017. Measures needed to enhance the performance and integrity of the FGD systems at Petersburg in order to meet these more stringent limits were approved by the IURC in IURC Cause No. 44794. On August 7, 2019, IDEM issued a Notice and Order of the Commissioner, as a result of an updated evaluation implementing the revised SO2 emissions limitations (i.e., 30-day rolling average) which became effective on September 24, 2019. As required, AES Indiana has been complying with these limits since they became effective through the operation of pollution controls equipment.

Currently, the counties in which AES Indiana operates fossil-fuel power generation facilities are all currently designated as attainment for all air pollutants. However, future revisions to NAAQS and/or revisions to attainment designations could result in additional requirements for AES Indiana EGUs.

New Source Review

On August 31, 2020, AES Indiana reached a settlement with EPA, the DOJ, and IDEM resolving the purported violations of the CAA and alleged in NOVs issued by EPA in 2009, 2015, and 2016, with respect to the coal-fired generation units at AES Indiana's Petersburg Generating Station. The alleged violations were included in NOVs AES Indiana received in 2009, 2015, and 2016. The settlement agreement, in the form of a proposed judicial consent decree, was approved and entered by the U.S. District Court for the Southern District of Indiana on March 23, 2021, and includes, among other items, the following requirements: annual caps on NOx and SO2 emissions and more stringent emissions limits than AES Indiana's prior Title V air permit; payment of civil penalties totaling $1.525 million (the payment of which was satisfied by AES Indiana in April 2021); a $5 million environmental mitigation project consisting of the construction and operation of a new, non-emitting source of generation at the site; expenditure of $0.325 million on a state-only environmentally beneficial project to preserve local, ecologically-significant lands (notice of completion of which was provided May 8, 2025 and confirmed satisfactory by IDEM on September 8, 2025); and retirement of Petersburg Units 1 and 2 prior to July 1, 2023. If AES Indiana did not meet this retirement obligation, it would be required to install a Selective Non-Catalytic Reduction ("SNCR") on Petersburg Unit 4.

AES Indiana paid the civil penalties of $1.525 million and the $0.325 million on a state-only environmentally beneficial project. AES Indiana also retired Petersburg Units 1 and 2 prior to July

1, 2023. In 2022, EPA approved AES Indiana's "Environmental Mitigation Project Plan" for a $5 million environmental mitigation project. AES Indiana has five years from the date of EPA's approval (until August 13, 2027) to complete its execution of the Plan. Once the Environmental Mitigation Project has been completed to the satisfaction of EPA, AES Indiana may request Termination of the Consent Decree.

Greenhouse Gas Regulations

On October 23, 2015, EPA finalized CO2 emission rules for existing power plants under CAA Section 111(d), called the Clean Power Plan ("CPP"). On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of legal challenges to the rule. On July 8, 2019, EPA published the final Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, known as the Affordable Clean Energy ("ACE") Rule along with associated revisions to implementing regulations. The final ACE Rule established CO2 emission rules for existing power plants under CAA Section 111(d) and replaced EPA's 2015 CPP. In accordance with the ACE Rule, EPA determined that heat rate improvement measures are the Best System of Emissions Reductions for existing coal-fired electric generating units. The final rule required the state of Indiana to develop a state plan to establish CO2 emission limits for designated facilities, including Petersburg's coal-fired electric generating units. States had three years to develop their plans under the rule. However, on January 19, 2021, the D.C. Circuit Court of Appeals vacated and remanded to EPA the ACE Rule but withheld issuance of the mandate that would effectuate its decision. On February 22, 2021, the D.C. Circuit Court of Appeals granted EPA's unopposed motion for a partial stay of the issuance of the mandate on vacating the repeal of the CPP. On March 5, 2021, the D.C. Circuit Court of Appeals issued the partial mandate effectuating the vacatur of the ACE Rule. In effect, the CPP did not take effect while EPA would be addressing the remand of the ACE Rule by promulgating a new Section 111(d) rule to regulate greenhouse gases from existing electric generating units. On June 30, 2022, the U.S. Supreme Court reversed the decision of the D.C. Circuit Court of Appeals' January 2021 decision and held that the "generation shifting" approach in the CPP exceeded the authority granted to EPA by Congress under CAA Section 111(d). As a result of the June 30, 2022 U.S. Supreme Court decision, on October 27, 2022, the D.C. Circuit issued a partial mandate holding pending challenges to the ACE Rule in abeyance while EPA developed a replacement rule.

On May 9, 2024, EPA published final NSPS*s* for new sources (established under Section 111(b) of the CAA) and existing sources (established under Section 111(d) of the CAA). The NSPSs are currently subject to legal challenges and subsequent proposed rulemaking is described in Pending and Future Environmental Regulations.

New Sources

The NSPS for new[51] fossil-fuel fired combustion turbines establishes CO2 emission rate limits, dependent upon capacity factor. For low load units (capacity factor of less than or equal to 20%), the NSPS establishes an emissions limit that applies upon start up and that is based on the use of lower emitting fuels (natural gas or distillate oil) ranging from 120-160 lb CO2/MMBtu. For

[51] New units are those that commence construction after May 23, 2023.

intermediate load units (capacity factor greater than 20% through 40%), the NSPS establishes an emissions limit that applies upon startup and that is based on high efficiency simple cycle technology ranging from 1,170-1,560 lb CO_2/MWh-gross.

For base load units (capacity factor greater than 40%), the NSPS establishes an emissions limit that applies upon startup that is based on high efficiency combined cycle technology ranging from 800-1,250 lb CO_2/MWh-gross. On January 1, 2032, the emissions limit lowers and is based on the addition of carbon capture and storage ranging from 100-150 lb CO_2/MWh-gross.

Existing Sources

The regulation finalized under Section 111(d) of the Clean Air Act requires states with affected existing coal-fired and existing natural gas-fired steam generating EGUs (i.e., electric utility boilers) to submit State Plans to EPA for approval. State Plans must include standards of performance (i.e., emissions limitations) for each affected existing unit in the state based on EPA's determined Best System of Emissions Reductions ("BSER") for the particular subcategory of unit. EPA established presumptively approvable standards of performance for states to use in establishing emissions limitations in their State Plans. However, states may apply less stringent, in some circumstances, or more stringent emissions limitations than the presumptively approvable standards.

For existing coal-fired affected EGUs, EPA finalized Emissions Guidelines based on the timeframe for expected continued coal combustion. Coal-fired affected EGUs that commit to cease operation prior to January 1, 2032, are not subject to emissions limitations. Emissions Guidelines for coal-fired affected EGUs that plan to cease operation after January 1, 2032 and before January 1, 2039 are based on 40% natural gas co-firing with a presumptively approvable standard of 16% reduction in emissions rate compared to a unit specific baseline with compliance required starting for calendar year 2030. Emissions Guidelines for coal-fired affected EGUs that plan to operate after January 1, 2039 are based on 90% carbon capture and sequestration with a presumptively approvable standard of 88.4% reduction in emissions rate compared to a unit-specific baseline with compliance required starting for calendar year 2032.

For existing natural gas-fired affected EGUs, EPA finalized Emissions Guidelines based on load type with compliance required starting for calendar year 2030. Emissions Guidelines for low load affected EGUs are based on use of uniform fuels with a presumptively approvable emissions limit of 130 pounds CO_2 per million Btu (lb CO_2/MMBtu). Emissions Guidelines for intermediate load EGUs are based on routine methods of operation and maintenance with a presumptively approvable emissions limit of 1,600 pounds per megawatt hour (gross) (lb/MWh-gross). Emissions Guidelines for base load EGUs are also based on routine methods of operation and maintenance, but with a presumptively approvable emissions limit of 1,400 lb/MWh-gross.

AES Indiana's natural-gas fired Harding Street Units 5, 6, and 7 and Petersburg Units 3 and 4 (upon repowering to natural gas) would be considered existing natural-gas fired EGUs and would be subject to emissions limits based on routine methods of operation and maintenance, as established in a State Plan. As such, it is not expected that additional capital investment or operational expenses would be required beyond routine methods of operation and maintenance.

Existing Controls to Reduce Air Emissions

As shown in Figure 7-1 below, AES Indiana has already installed environmental pollution control equipment at its facilities.

Figure 7-1: AES Indiana's Existing Pollution Control Equipment

Unit	Fuel	ICAP (MW)	Environmental Controls
Petersburg Unit 3	Coal	532	FGD, SCR, BH, ACI, SI
Petersburg Unit 4	Coal	538	FGD, NN, LNB, ESP, ACI, SI
Petersburg DG	Diesel	8	
HSS Unit 5	Natural Gas	96	
HSS Unit 6	Natural Gas	102	
HSS Unit 7	Natural Gas	420	SCR
HSS CTs 1-2	Oil	60	
HSS CT 4	Oil/Natural Gas	73	Water injection
HSS CT 5	Oil/Natural Gas	75	Water injection
HSS CT 6	Natural Gas	146	LNB
HSS DG	Diesel	3	
Georgetown GT1	Natural Gas	72	LNB
Georgetown GT4	Natural Gas	69	LNB
Eagle Valley CT1	Natural Gas	341	LNB, SCR, OC
Eagle Valley CT2	Natural Gas	341	LNB, SCR, OC

Note: Acronyms used in Figure 7-1: Activated Carbon Injection ("ACI"); Electrostatic Precipitator ("ESP"), Flue Gas Desulfurization (FGD), Low NOx Burner ("LNB"), Neural Net ("NN"), Oxidation Catalyst ("OC"), Selective Catalytic Reduction ("SCR"), and Sorbent Injection ("SI").

7.2.2 Water Standards

The NPDES permit program obtains its authority under the Clean Water Act ("CWA"). Section 402 requires permits for the direct discharge of pollutants to the waters of the U.S from an industrial process. These permits, which AES Indiana maintains for Harding Street, Eagle Valley, and Petersburg have five main components: technology and water quality based effluent limitations; monitoring requirements; and record keeping and reporting requirements; special conditions; and standard conditions. These permits are valid for a period of 5 years and are renewed at the end of the permit term.

These permits can include new and/or revised limits and/or additional parameter specific monitoring and reporting requirements. When a permit is renewed effluent limits, monitoring, reporting and special conditions are re-evaluated. Effluent limitations identify the nature and amount of specific pollutants that facilities may discharge from regulated outfalls based on water quality (as applicable per 327 IAC 2-1-6) and technology-based standards (as applicable per 40 CFR Part 423).

In addition to establishing effluent limits, the NPDES permit also includes requirements associated with Section 316(a) and Section 316(b) of CWA which are described below.

Clean Water Act Section 316(a)

327 IAC 5-7 and Section 316(a) of the CWA authorize the NPDES permitting authority, IDEM, to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of temperature water quality effluent limits that would otherwise be required under sections 301 or 306 of the CWA. Regulations implementing Section 316(a) are codified in 40 CFR Part 125, subpart H. These regulations and associated guidance identify the criteria and process for determining whether an alternative effluent limitation (i.e., a thermal variance from the otherwise applicable effluent limit) may be included in an NPDES permit and, if so, what the limits should be. This means that before a thermal variance can be granted, the permittee must demonstrate that the otherwise applicable thermal discharge water quality based effluent limit is more stringent than necessary to assure the protection and propagation of the waterbody's Balanced Indigenous Population ("BIP") of shellfish, fish, and wildlife. In November 2023, IDEM issued the final NPDES permit renewal for Harding Street with an effective date of January 1, 2024. The permit includes new 316(a) thermal limitations, that could result in the need for AES Indiana to take additional action to ensure compliance with the final permit. In December 2023, AES Indiana filed a petition for appeal of certain new requirements, including the new thermal limitations, in the final Harding Street NPDES permit. A stay of the appealed requirements was initially granted on January 4, 2024, and is in effect until November 6, 2025 (as extended from August 6, 2025), which could be further extended. If AES Indiana is unable to obtain an acceptable Section 316(a) variance based, Indiana thermal water quality standards would apply. In this scenario, the potential impact could be similar to the range of impacts described under Section 316(b) and will be included in subsequent IRP analyses.

Cooling Water Intake Structures – Clean Water Act Section 316(b)

Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of Cooling Water Intake Structures ("CWIS") reflect the best technology available for minimizing adverse environmental impacts. Specifically, Section 316(b) is intended to reduce the impacts to aquatic organisms through impingement and entrainment due to the withdrawal of cooling water by facilities. On August 15, 2014, EPA published a final rule which would set requirements that establish the Best Technology Available ("BTA") to minimize these impacts. For the first time, both Harding Street and Peterburg NPDES permits include 316(b) BTA determinations. These BTA determinations will be re-reviewed every permit cycle.

The Petersburg BTA determination was based on significant flow reductions expected as a result of Units 1 and 2 retirement and Units 3 and 4 existing closed cycle cooling which will result in meeting closed cycle recirculating system which is the best performing technology to reduce the adverse impacts.

The Harding Street BTA determination was based on flow reductions due to Units 3 and 4 cooling water intake structure retirement and Unit 7 being closed cycle along with the addition of a modified traveling water screen with fish handling and return system. However, during the next permit cycle review the entrainment BTA could be determined to be closed cycle cooling systems or significant modifications to the intake structure itself.

The impact of this rule will be dependent upon IDEM's future determination for impingement and entrainment BTAs for both Petersburg and Harding Street.

7.2.3 Solid Waste Standards

The solid waste generated at AES Indiana's power plants is classified as either non-hazardous waste or hazardous waste. AES Indiana generates hazardous and non-hazardous waste with the handling of both waste streams regulated under the Resource Conservation and Recovery Act ("RCRA").

Hazardous Waste

Hazardous waste is regulated under RCRA Subtitle C. There are three categories of hazardous waste generators for industry with each category having its own scope of regulations that must be met. The more hazardous waste that is generated, the higher the risk to the environment, hence more regulation and oversight is imposed.

The three categories of hazardous waste are: 1) Large Quantity Generator ("LQG"); 2) Small Quantity Generator ("SQG"); and 3) Very Small Quantity Generator ("VSQG"). AES Indiana's generating plants are historically categorized as SQG and VSQG. As such, AES Indiana faces relatively minimal regulations and risk in this area.

Non-Hazardous Waste

Non-hazardous waste is regulated under Subtitle D of RCRA. AES Indiana's coal-fired operations have historically generated a large amount of solid waste every year that must be handled in accordance with this regulation. The primary sources of non-hazardous waste in the coal-fired steam electric industry are fly ash and bottom ash generated from coal combustion, and scrubber sludge or gypsum resulting from the FGD process. These types of waste are collectively known as coal combustion residuals ("CCR")

CCR was historically placed in ponds for treatment via sedimentation, from which the effluent discharge is regulated pursuant to NPDES. CCR dredged from the ponds has historically been shipped back to mines or otherwise beneficially used in an environmentally sound manner. In addition, fly ash has been mixed with dewatered scrubber sludge and lime to make a stabilized product, which is disposed of in a permitted, on-site landfill at Petersburg. Further, the Petersburg Unit 4 (and Petersburg Units 1 and 2 prior to retirement and HSS Unit 7 FGD prior to conversion to natural gas), produce commercial grade gypsum from FGD operations that can be beneficially used for wallboard manufacturing, cement manufacturing, and agricultural use. In general, ash management activities did not change for several years.

On April 17, 2015, EPA published the final CCR Rule, which regulates CCR as non-hazardous waste under Subtitle D of the RCRA. The CCR Rule established national minimum criteria for existing CCR surface impoundments (ash ponds), including location restrictions, structural integrity, design and operating criteria, groundwater monitoring and corrective action, closure requirements, and post closure care. Failure to demonstrate compliance with the national minimum criteria results in the requirement to cease use of and close existing active ponds within five years, with potential for extensions, as needed. In 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act authorized states to establish CCR permitting programs and required EPA to establish a program for states that do not adopt one.

On May 8, 2024, EPA published final revisions to the 2015 CCR rule expanding the scope of the rule to include CCR Management Units ("CCRMU"). A CCRMU is any area of land on which a non-containerized accumulation of CCR is received or managed at any time at a regulated facility, including past beneficial use. Eagle Valley, Harding Street and Petersburg facilities are required to conduct a two-part facility evaluation to determine the presence of CCRMUs, consisting of document and records review (Part 1) and a physical facility inspection (Part 2). Facilities will be required to identify and delineate CCRMUs containing one (1) ton of CCR or more. CCRMUs exceeding 1,000 tons will be subject to the CCR Rule requirements for groundwater monitoring, corrective measures, closure/post-closure, and public data disclosure.

AES Indiana's Eagle Valley ceased coal combustion in 2016. Closure construction of Eagle Valley ash ponds A, B and C began in April 2025 following an IDEM approved closure and post closure plan which includes the removal of CCR material that has determined to be below the season high groundwater table, and the installation of an engineered cover system over the closure footprint to prevent infiltration. AES Indiana has submitted a closure and post closure plan for Eagle Valley's former ash ponds D and E to IDEM for review and approval. This plan follows a similar closure plan to the one being implemented for ash ponds A, B and C. AES Indiana continues to collect groundwater data for Eagle Valley as required by the CCR rule and has completed the evaluation of the nature and extent of the groundwater impacts at the facility. The data indicates exceedances of certain groundwater protection standards in the groundwater on AES Indiana's Eagle Valley property, and on adjacent properties. The nature and extent evaluation data was used to update the 2019 Corrective Measures Assessment (CMA) in 2024. As required by the CCR rule, in May 2024, AES Indiana hosted a public meeting to present the results of the 2024 CMA update for Eagle Valley and receive feedback and comments from affected and interested parties. AES Indiana continues to evaluate data and information to select a remedy for Eagle Valley.

AES Indiana was unable to successfully demonstrate compliance for Petersburg with certain safety factor requirements set forth in the CCR rule, which are required to maintain operation of the ponds. As a result, AES Indiana removed the ponds from service and made modifications to handle the material that was previously sent to the ash ponds[52]. AES Indiana has since completed for Petersburg the closure of the ash ponds and has initiated the closure of the on-site landfill, in accordance with a closure and post closure plan approved by IDEM. Closure of the ash ponds and the landfill include the installation of an engineered cover system to prevent infiltration. AES

[52] As approved in IURC Cause No. 44794, AES Indiana installed a closed-loop bottom ash handling system to dewater the bottom ash that would otherwise have been sluiced to the ponds.

Indiana continues to collect groundwater data for Petersburg as required by the CCR rule and has completed the evaluation of the nature and extent of the groundwater impacts at the site. The data indicates exceedances of certain groundwater protection standards in the groundwater limited to AES Indiana's property. AES Indiana is currently using nature and extent evaluation data to update the 2019 CMA for Petersburg. Once the CMA update is completed, AES Indiana will host a public meeting to present the results of the updated CMA and receive feedback and comments from affected and interested parties, as required by the CCR rule. AES Indiana will then select a remedy for Petersburg no earlier than 30 days after the public meeting.

AES Indiana's Harding Street ceased coal combustion in 2016. As required by the CCR rule, AES Indiana continues to collect groundwater data for Harding Street as required by the CCR rule and has completed the evaluation of the nature and extent of the groundwater impacts at the site. The data indicates exceedances of certain groundwater protection standards in the groundwater on AES Indiana's Harding Street property, and on an adjacent property. The nature and extent evaluation data was used to update the 2019 CMA in 2025. In September 2016, AES Indiana hosted a public meeting to present the results of the 2025 Harding Street CMA update and solicit feedback and comments from affected and interested parties. As part of the CMA process, AES Indiana continues to evaluate closure alternatives for the Harding Street ash pond system and once an alternative is selected, the closure and post closure plan will be submitted to IDEM for review and approval.

7.3 Pending and Future Environmental Regulations

170 IAC 4-7-6(a)(4)

There are several environmental initiatives that are being considered at the federal level that may impact the cost of electricity. This section discusses these pending and future federal environmental regulations.

7.3.1 Greenhouse Gases ("GHG")

As discussed above, GHG regulations have faced a number of iterations and legal challenges. The 2024 GHG NSPSs described above are subject to legal challenges but remain in effect. On October 16, 2024, the U.S. Supreme Court denied emergency stay applications. On June 17, 2025, EPA published a proposed rule to repeal the May 9, 2024 final rules for new and existing EGUs in addition to 2015 greenhouse gas new source performance standards for certain new EGUs. In this proposed rule, the EPA also offered an alternative proposal to repeal a narrower set of greenhouse gas requirements which would include the repeal of requirements for existing EGUs and requirements based on carbon capture and sequestration for new EGUs.

7.3.2 National Ambient Air Quality Standards

As discussed above, NAAQS are routinely reviewed and potentially lowered by EPA. It is also possible that revised NAAQS may result in future revisions to CSAPR. As a result, future required reductions of SO2 and NOx are possible.

7.3.3 Cross State Air Pollution Rule

As discussed above, revisions to the CSAPR could result in future requirements for AES Indiana. CSAPR could be revised for various reasons, including to address lowered NAAQS and to address litigation related to CSAPR-related rulemakings.

7.3.4 Coal Combustion Residuals

On February 20, 2020, EPA published a proposed rule to establish a federal CCR permit program that would operate in states without approved CCR permit programs. If this rule is finalized before Indiana establishes a final state-level CCR permit program, AES Indiana could eventually be required to apply for a federal CCR permit from EPA. In response to the EPA's proposed rule, IDEM issued a First Notice of Comment Period regarding establishment of a state-level CCR permit program on October 13, 2021. After a Second Notice of Comment Period, on December 11, 2024, the Indiana Environmental Rules Board (ERB) preliminary adopted IDEM's proposed CCR rulemaking which includes regulation of CCR through a state permitting program and the incorporation of the federal CCR rule by reference. The state rule, if finalized, and would become effective and be implemented after EPA's review and approval.

On July 22, 2025, EPA published a proposed rule to extend the CCRMUs compliance deadlines established in the 2024 revisions to the CCR rule. The proposed rule would allow facilities to submit the two parts of the facility evaluations concurrently, while also extending the deadline for CCRMUs compliance with groundwater monitoring requirements. EPA is also proposing an additional 12-month extension for facilities to complete both parts of the facility evaluations. These extensions would be applicable to AES Indiana's Harding Street, Eagle Valley and Petersburg.

Corrective actions or remedies related to the CCR Rule would occur regardless of a generating station's operating scenario as these costs would be related to remedies for impacts related to ash ponds that are being phased out.

7.3.5 Steam Electric Power Generating Effluent Limitation Guidelines ("ELGs")

In May 2024, EPA published the final ELGs (40 CFR 423). The rule establishes more stringent discharge standards/limits for three wastewaters generated at steam generating power plants: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate term. The rule also establishes a new set of definitions and establishes new effluent limitations for various legacy wastewaters, which may be present in surface impoundments. On October 2, 2025, EPA published a proposed rule and a companion direct final rule to extend certain deadlines associated with the May 9, 2024 rule. These limits are based on various wastewater stream specific treatment technologies. AES Indiana facilities' NPDES permits may be updated to include applicable ELG effluent limits that could potentially impact AES Indiana.

7.4 Summary of Potential Impacts

These regulations would potentially require AES Indiana to incur additional expenses for compliance in the future. Figure 7-2 below provides a summary of these potential regulations including potential timing and preliminary cost estimates available at this time.

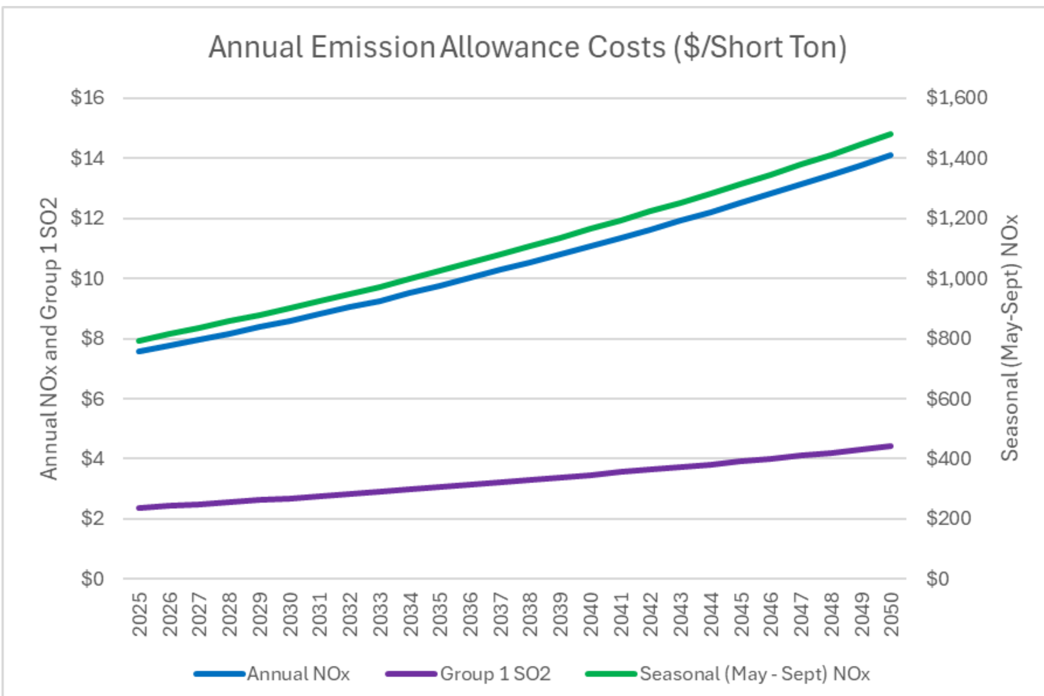
Figure 7-2: Estimated Cost of Potential Environmental Regulations

Rule	Expected Implementation Year	Capital Cost Range Estimate ($MM)	Assumed Technology
CWIS 316(b)*	2030-2033	50-100	Closed cycle cooling
ELG	2028-2031	0-60	Physical/Chemical Wastewater Treatment System

**The 316(b) technology listed is the same technology that would be needed for compliance with the temperature water quality standards for AES Indiana's Harding Street.*

AES Indiana will continue to evaluate impacts of the potential environmental regulations depicted in Figure 7-3, but they are not included in this IRP. Allowances can be purchased to comply with CSAPR NOx and SO2 requirements. Emissions allowance prices are shown in Figure 7-3.

Figure 7-3: Estimated Cost of Potential Environmental Regulations



Section 8: Resource Portfolio Modeling

170 IAC 4-7-4(5), 170 IAC 4-7-4(11), 170 IAC 4-7-4(22), 170 IAC 4-7-4(28), 170 IAC 4-7-8(a), and 170 IAC 4-7-8(c)(4)

8.1 Modeling Overview for the 2025 IRP

170 IAC 4-7-4(8) and 170 IAC 4-7-4(19)

8.1.1 Model Overview

AES Indiana utilized the EnCompass Power Planning Software, the same model utilized in the 2022 IRP. AES Indiana provided stakeholders access to its model database, which enabled those with EnCompass licenses to run AES Indiana's IRP portfolios. To support EnCompass modeling efforts, AES Indiana contracted with ACES Power Marketing LLC (ACES) to provide consulting services in AES Indiana's 2025 IRP. ACES provided the fundamental forecasts (power and gas) used in the IRP and conducted the stochastic modeling.

Key Modeling Highlights

- → AES Indiana utilized Yes Energy's EnCompass modeling platform for capacity expansion (utility capital accounting) and production cost modeling.
- → As a modeling framework, the Company performed traditional deterministic capacity expansion scenario analysis of four different loads (no data centers, low data centers, mid data centers, and high data centers) across four scenarios to produce 16 distinct portfolios. Scenarios refer to possible future states of the world; portfolios refer to unique resource combinations. These 16 distinct portfolios were dispatched across each of the four scenarios to produce 64 runs for evaluation.
- → AES Indiana utilized fundamentals-based forward curves provided by ACES. The team at ACES has extensive experience in integrated resource planning and provides EnCompass-ready price forecasts, allowing for a single software solution.
- → For the Scorecard analysis, AES Indiana conducted deterministic scenarios and sensitivities for key variables to stress portfolios and identify the impacts of sources of future uncertainty.
- → For the Scorecard analysis, stochastic simulations were run for the 16 distinct portfolios through the Reference case scenario. This work captured volatility around commodity prices, load, and renewable generation.

8.2 Modeling Tools and Framework

170 IAC 4-7-4(19)

AES Indiana utilized the EnCompass Power Planning Software, the same model utilized in the 2022 IRP. The EnCompass platform provides a comprehensive suite of modeling capabilities, including capacity expansion optimization, utility capital accounting, and hourly production cost modeling, all optimized over a 25-year horizon.

For the IRP Modeling Framework, cases and scenarios are defined as:

Data Center Cases

→ The base set of model runs for the 2025 IRP includes no data center load. The AES Indiana load forecast is based on traditional load forecasting methodologies, developed in partnership with Itron to develop base, low, and high load forecasts through 2050.

→ As described in Section 5.6, AES Indiana also evaluated three different trajectories for data center load:

- Low Data Center Case: projects 500 MW of new data center load by 2035
- Mid Data Center Case: projects 1,500 MW of new data center load by 2035
- High Data Center Case: projects 2,500 MW of new data center load by 2035

→ Data center load was scaled linearly on a monthly basis to ramp up to the target volumes by the end of calendar year 2035.

Scenarios

→ Scenarios are views of the futures defined by external influences, such as political outcomes, economics, regulations, etc.

→ In the planning model, each scenario was modeled with a unique set of input assumptions that correspond to the external influences defining the scenario.

8.2.1 Scenario Framework

170 IAC 4-7-4(25) and (26)

AES Indiana included four scenarios in the Scenario Analysis. These scenarios are views of the futures defined by external influences like political outcomes, economics, regulations, etc.

The nomenclature of the four scenarios reflects the range of environmental policy and regulation futures. These scenarios include the following:

8. Reference Case
9. Challenged Gas Infrastructure
10. High Regulatory: Environmental
11. Stable Markets

Each scenario uses a unique set of driving assumptions that align with the future view of the corresponding scenario and act as defining inputs into the EnCompass model. The assumptions categories include:

→ *Environmental Policy Assumptions* – The primary environmental regulation considered for this IRP is the EPA Greenhouse Gas (“GHG”) Rules under Clean Air Act 111(b).

- → *Tax Credits* - Assumptions for ITC and PTC by technology
- → *Load Forecast* – As discussed in Section 6 of this report, AES Indiana and Itron modeled three load forecasts (low, base, and high) to serve as load scenarios that correspond to IRP scenario outlooks.
- → *Commodity Forecasts* – The commodity assumptions that serve as drivers to the IRP scenarios include price forecasts for natural gas, power, and capacity. Each scenario in this IRP uses a commodity forecast that reasonably represents the scenario's outlook. For more information on the sources for these commodity forecasts and as a reference for the discussion below, please see Section 8.3.1.
- → *Electric Vehicle and Distributed Solar Forecasts* – In addition to the three load scenarios, AES Indiana also worked with Carnegie Mellon to forecast different levels of electric vehicle and distributed solar adoption in AES Indiana's service territory. Carnegie Mellon developed three different electric vehicle forecasts (low, base, and high) and three different distributed solar forecasts (low, base, and high).

Figure 8-1 provides an overview of the input assumptions included in each scenario.

Figure 8-1: Overview of Input Assumptions by Scenario

Scenario Driver ↓	Reference case	Gas infrastructure challenges	High regulatory: environmental	Stable market scenario
EPA GHG NSPS	Repealed	Repealed	**111B remains in effect**	Repealed
Tax credits (ITC/PTC)	OBBBA	OBBBA	**IRA reinstatement + extension**	OBBBA
AES Indiana load	Base	Base	↑	↓
Natural gas prices	Base	↑	↑	↓
Thermal CAPEX	Base	Base[1]	↑	↓
Renewables CAPEX	Base	Base	Base	↓
EV/distributed solar	↓	Base	↑	Base

[1] High fixed O&M to reflect high firm gas transportation costs

Scenario 1: *Reference Case*

The Reference Case scenario represents all projected future laws and changes to existing laws and regulations, a base case view of load and commodity markets, and a starting point for new resource costs that reflect current market pricing.

Figure 8-2: Reference Case Drivers with Description

Scenario Driver	Variable Impact	Description
EPA GHG NSPS	Repealed	The EPA GHG rules are assumed to be repealed; thus, no restrictions are placed on new natural gas plants in the model.
Tax credits (ITC/PTC)	OBBBA	Tax credits (ITC/PTC): Tax credits are modeled per the OBBBA, with storage and nuclear credits running through the mid-2030s, while solar and wind credits expire for projects in service.
AES Indiana load	Base	The Base Load Forecast for AES Indiana load (before DSM and data centers) is used in this scenario.
Natural gas prices	Base	Base natural gas prices are in the $3.00-$4.50/MMBtu range for the study.
Thermal CAPEX	Base	Capital costs for new thermal projects reflect the recent supply chain and EPC constraints seen in the overall gas turbine market.
Renewables CAPEX	Base	Capital costs for new wind, solar, and storage reflect near-term pricing as seen from AES Indiana’s 2024 All-Source RFP.
EV/distributed solar	↓	The low electric vehicle and distributed solar forecasts are used in the Reference Case to reflect recent actual data along with tax credit expirations detailed in the OBBBA.

Scenario 2: ***Natural gas infrastructure and supply challenges***

The Gas Infrastructure Challenges scenario is intended to reflect a scarcity of natural gas supply, which impacts natural gas prices and competition for firm gas supply.

Figure 8-3: Challenge Gas Infrastructure Drivers with Description

Scenario Driver	Variable Impact	Description
EPA GHG NSPS	**Repealed**	The EPA GHG rules are assumed to be repealed; thus, no restrictions are placed on new natural gas plants in the model.
Tax credits (ITC/PTC)	**OBBBA**	Tax credits (ITC/PTC): Tax credits are modeled per the OBBBA, with storage and nuclear credits running through the mid-2030s, while solar and wind credits expire for projects in service.
AES Indiana load	**Base**	The Base Load Forecast for AES Indiana load (before DSM and data centers) is used in this scenario.
Natural gas prices	↑	**High natural gas prices are in the $5.50-$8.00/MMBtu range for the study.**
Thermal CAPEX	**Base**[1]	**Base capital costs are used, but fixed O&M costs are approximately 16% higher, reflecting higher firm gas transportation costs.**
Renewables CAPEX	**Base**	Capital costs for new wind, solar, and storage reflect near-term pricing as seen from AES Indiana's 2024 All-Source RFP.
EV/distributed solar	**Base**	**High natural gas and oil prices are expected to drive faster growth in electric vehicle adoption. Higher power prices driven by high natural gas prices drive more investment in distributed solar.**

Scenario 3: ***High regulatory: environmental***

The High Regulatory scenario reflects a pendulum swing in federal and state emphasis on environmental regulation. Two key pieces of Biden-era environmental regulation come back into play: (1) the EPA Greenhouse Gas ("GHG") rules, particularly Section 111(b) that applies to new natural gas plants, and (2) IRA tax credits for wind, solar, storage, and other zero-carbon resources are reinstated and extended through the end of the study.

Additionally, more stringent regulations on upstream drilling, transportation, and storage of natural gas raise natural gas prices, driving up power prices. While demand would be lower, continued EPC strain and other regulations would increase the cost of building new thermal gas plants by about 25%.

Solar and storage baseline costs remain benchmarked to recent pricing trends, but wind costs are 25% lower to reflect a renewed interest and federal and state support for wind development in the state. The reinstatement of tax credits for EVs and distributed solar provides a jolt to consumer-facing industries, pushing those forecasts into the high case.

Figure 8-4: High Regulatory: Environmental Drivers with Description

Scenario Driver	Variable Impact	Description
EPA GHG NSPS	**111B remains in effect**	The EPA GHG rules are assumed to be repealed; thus, no restrictions are placed on new natural gas plants in the model.
Tax credits (ITC/PTC)	**IRA reinstatement + extension**	Tax credits (ITC/PTC): Tax credits are modeled per the OBBBA, with storage and nuclear credits running through the mid-2030s, while solar and wind credits expire for projects in service.
AES Indiana load	↑	The Base Load Forecast for AES Indiana load (before DSM and data centers) is used in this scenario.
Natural gas prices	↑	**High natural gas prices are in the $5.50-$8.00/MMBtu range for the study.**
Thermal CAPEX	↑	**High capital costs are assumed for new natural gas technologies.**
Renewables CAPEX	Base	Capital costs for new solar and storage reflect near-term pricing as seen from AES Indiana's 2024 All-Source RFP. **Wind capex is reduced by 25% to reflect renewed interest and improved wind-siting conditions.**
EV/distributed solar	↑	**High natural gas and oil prices are expected to drive faster growth in electric vehicle adoption. Higher power prices driven by high natural gas prices drive more investment in distributed solar.**

Scenario 4: *Stable market scenario*

The Stable Market scenario reflects a deflationary period for the prices of natural gas, power, and the capital cost of new resources. This scenario returns capital costs for natural gas, wind, and solar to the 2017-2021 time frame, before supply chain disruptions, inflation, and other market forces led to cost increases for all three technologies.

Figure 8-5: Stable Market Drivers with Description

Scenario Driver	Variable Impact	Description
EPA GHG NSPS	**Repealed**	The EPA GHG rules are assumed to be repealed; thus, no restrictions are placed on new natural gas plants in the model.
Tax credits (ITC/PTC)	**OBBBA**	Tax credits (ITC/PTC): Tax credits are modeled per the OBBBA, with storage and nuclear credits running through the mid-2030s, while solar and wind credits expire for projects in service.
AES Indiana load	↓	**The High Load Forecast for AES Indiana load (before DSM and data centers) is used in this scenario.**
Natural gas prices	↓	**Low natural gas prices are in the \$2.00 - \$3.00/MMBtu range for the study.**
Thermal CAPEX	↓	**Low capital costs are assumed for new natural gas technologies.**
Renewables CAPEX	↓	**Low capital costs are assumed for wind, solar, and storage technologies.**
EV/distributed solar	**Base**	**In a lower-priced environment, cheaper electric vehicles and distributed solar systems drive investment closer to the Base Case forecast.**

8.2.2 Fundamental Commodity Curves

AES Indiana worked with ACES to develop four commodity scenarios for AES Indiana's 2025 IRP. Below is a summary of the ACES commodity scenario corresponding to the AES Indiana IRP scenario.

ACES 2024 Fall Fundamental Forecast

ACES produces two fundamental forecasts per year. The forecasts include several scenarios. Inputs to the fundamental model include commodity prices such as coal and gas forward curves. The primary outputs are monthly on and off-peak power prices for a particular area, hourly power prices, and generation mix details.

What is a fundamental forecast?

A fundamental model is used to produce long-term fundamental power prices rather than forward curves traded on an exchange. The fundamental model runs long-term resource dispatch for a large area such as North America or the Eastern Interconnect. It performs capacity expansion optimization, making selections for unit retirements and additions within constraints and building a generation portfolio for the system. A dispatch engine simulates that generation portfolio to meet hourly demand, solving for an hourly power price.

ACES' 2024 Fall Fundamental Forecast uses EnCompass to create fundamental curves through 2050. ACES leverages the National Database from Horizons Energy, which is pre-loaded with over 20,000 generation resources across North America. The grid topology is simplified to 78 areas across North America, rather than the tens of thousands of nodes that represent actual resources and load points. This allows ACES to produce a fundamental outlook that serves as a relevant price hub for most of the country.

Fundamental curves are best used for long-term planning processes such as IRPs and asset valuation. They can be helpful in scenario analysis and understanding the underlying generation mix that influences power market dynamics. However, they are not a transactable forward curve and do not replace the need for more specific and timely market data for short-term or portfolio-specific decisions.

ACES Fall 2024 Fundamental Forecast Assumptions

A. Natural Gas – Henry Hub and 44 gas basis curves are marked from the October 2024 market curves and escalated at inflation. The relevant gas curve for AES Indiana is the Henry Hub curve.

B. Modeling parameters – Generic new wind resources (on-shore and off-shore) have different capacity factors by area, whereas generic new solar resources have different capacity factors by state. Generic new storage is modeled as 4-hour duration lithium-ion batteries. Generic new resources that run on natural gas include combustion turbines, combined-cycle gas turbines, and internal combustion engines. Other generic new resources include small modular reactors and coal plants.

C. Resource capital costs – Generic new resource capital costs utilize multiple sources:

a. The National Renewable Energy Laboratory's 2024 Annual Technology Baseline. ACES added an interconnection cost to the cost curve.

b. The Energy Information Administration's 2023 Annual Energy Outlook.

c. Lawrence Berkeley National Laboratory's 2023 Generation Interconnection Cost Report

d. Internal ACES intelligence

D. Wind, solar, and storage resources receive the production tax credit or the investment tax credit. These tax credits begin to phase out in 2034 (safe-harbor rules allowing this extension) and are 0% by 2036.

E. New resource build constraints were informed by looking at what is in existing interconnection queues when available and also by looking at the Energy Information Administration's Form 860m. An effort is made to recognize that new projects have a significant lead time. Constraints are tighter in the next five years and gradually loosen over the next ten years.

F. Resource Capacity Credit

a. Balancing authorities are modeled using an ICAP reserve margin. Thermal generators are accredited their economic max capacity for firm contributions. Renewables and storage vary by area but are typically modeled using a declining Effective Load Carrying Capability (ELCC) curve, such that the more added to the grid, the less each incremental megawatt receives in capacity accreditation. Some balancing authorities also model renewables and storage with seasonal variation.

G. Renewable Portfolio Standards and Clean Energy Standards

a. RPS and CES goals and targets were modeled for over 30 states. Targets were sourced from the National Conference of State Legislatures.53

ACES Fall 2024 Scenarios

ACES produces a variety of scenarios. Scenarios and assumptions relevant to AES Indiana are listed below.

A. Base Case – The status quo. Very little environmental legislation has been passed. There is no carbon legislation outside of what is already in place (WCI and RGGI), and the EPA Rule 111 is stayed or overturned. Most Areas experience 1-2% annual load growth, with a few exceptions, such as PJM-DOM and ERCOT, that are higher. Base Henry Hub costs are on the lower end, and the model tends to favor gas resources.

B. High Demand – Added high load factor load representing data center load growth to most Areas. Load forecasts come from the High Growth scenario of EPRI's 2024 whitepaper: Powering Intelligence. This forecast assumes a 10% annual growth of existing data center load by state. ACES increased some initial conditions based on known load additions, and

[53] https://www.ncsl.org/energy/state-renewable-portfolio-standards-and-goals

gradually tapered the annual growth rate down from 10% in 2030 to a sustained 3% by 2044. This implies the greatest surge in data center growth will occur over the next 10-15 years.

C. High Gas – A higher Henry Hub price is used. The scalar adjustment was taken from the EIA's 2023 AEO Low Oil and Gas Supply scenario, but was stressed an additional 40% higher to produce sufficient variation from the Base price. The price increase was phased in between 2025 and 2050.

D. Low Gas – A lower Henry Hub price is used. The scalar adjustment was taken from the EIA's 2023 AEO High Oil and Gas Supply scenario, but was further reduced by 25% to produce sufficient variation from the Base price. The price increase was phased in between 2025 and 2050.

E. GHG rules (EPA 111) – Assumes the EPA Rule 111 is upheld and enforced. As a simplifying assumption, all active coal plants are forced to cofire with 40% natural gas starting in 2032 and must retire at the beginning of 2039 (rather than investing in carbon capture technology). In addition, all new natural gas combustion turbines and combined cycles are limited to an annual capacity factor of 40%.

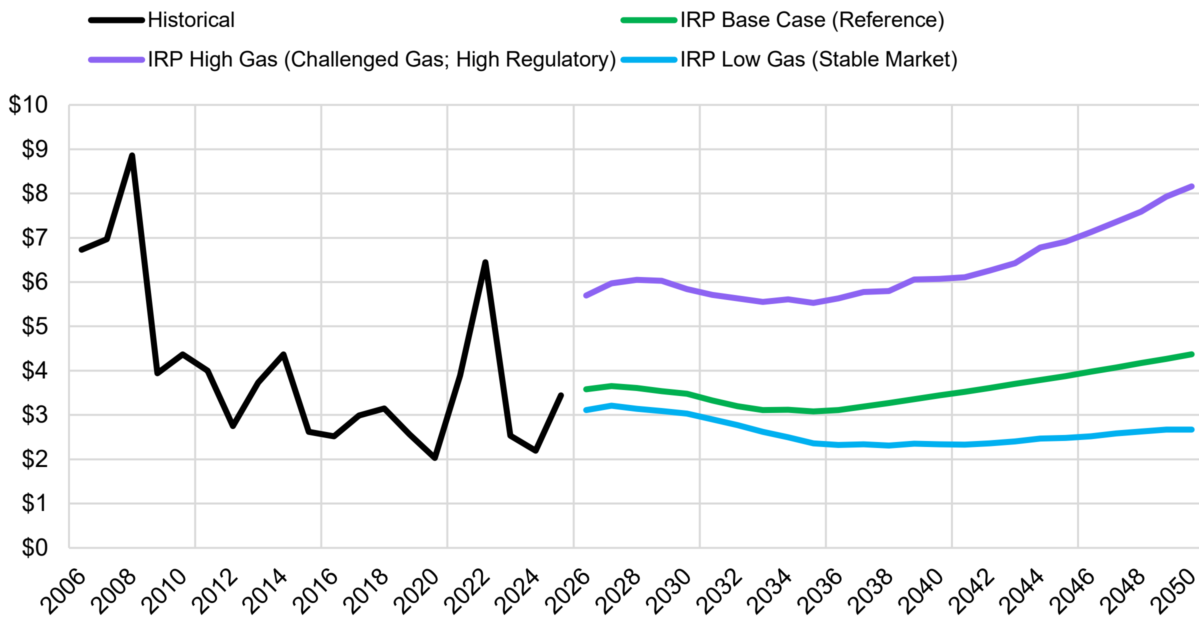
Figure 8-6: Mapping of fundamental curves to AES Indiana 2025 IRP scenarios

AES IN 2025 IRP scenario	ACES Scenario
Reference Case	ACES fall 2024 fundamental forecast – high demand without GHG rules
Gas Infrastructure Challenges	ACES fall 2024 fundamental forecast – high gas
High Regulatory: Environmental	ACES custom scenario – high demand with GHG rules. Additional sensitivity with high natural gas prices produced the final power cu
Stable Market Outlook	ACES fall 2024 fundamental forecast – low gas

Natural Gas Prices

In developing a long-term gas price, ACES uses market curves that provide some price discovery for the next 10+ years and escalates them at an inflation rate of around 2.5%. For the past 2-3 years, Henry Hub gas has been relatively stable, trading between $3-$4/MMBtu for 2030. There are certain areas of gas production, such as the Haynesville Shale Basin, that begin producing when prices are high enough, helping to modulate gas prices and offer some price stability. Given sustained low-to-moderate forward prices and the understanding that production can respond to demand, ACES' long-term gas price projections remain below $4/MMBtu over the next 10-15 years. There will undoubtedly be shocks to the market that temporarily drive prices up, but ultimately these should revert to more stable, lower levels given the expected fundamentals. A sustained higher price reflects fundamentally different assumptions from today and is better captured in the scenarios that utilize a high gas price.

Figure 8-7: Henry Hub Natural Gas Prices (Nominal $/MMBtu)



AES Indiana also partnered with ACES to produce a set of 100 stochastic draws for natural gas prices, power prices, AES Indiana load, and renewable production. Figure 8-8 depicts the stochastic modeling process that ACES developed, which utilizes a combination of observed historical volatility for modeling variables, with each variable anchored to a historical weather year. Figure 8-9 shows the stochastic range of Henry Hub natural gas prices overlayed with the deterministic pricing scenarios. The stochastic range includes monthly and daily volatility that exceeds the price range from deterministic pricing, providing additional value for assessing the risk of the 16 candidate portfolios.

Figure 8-8: Stochastic Modeling Process (Source: ACES)

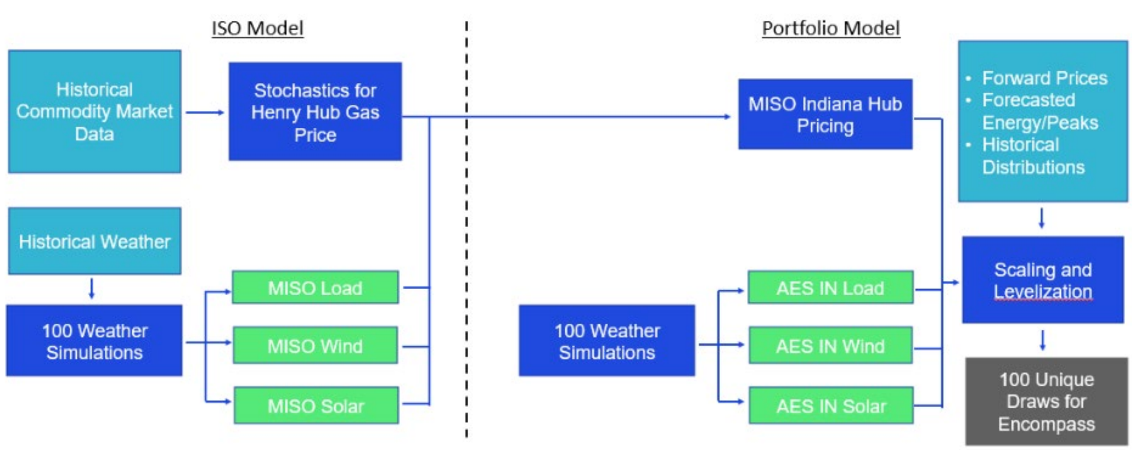
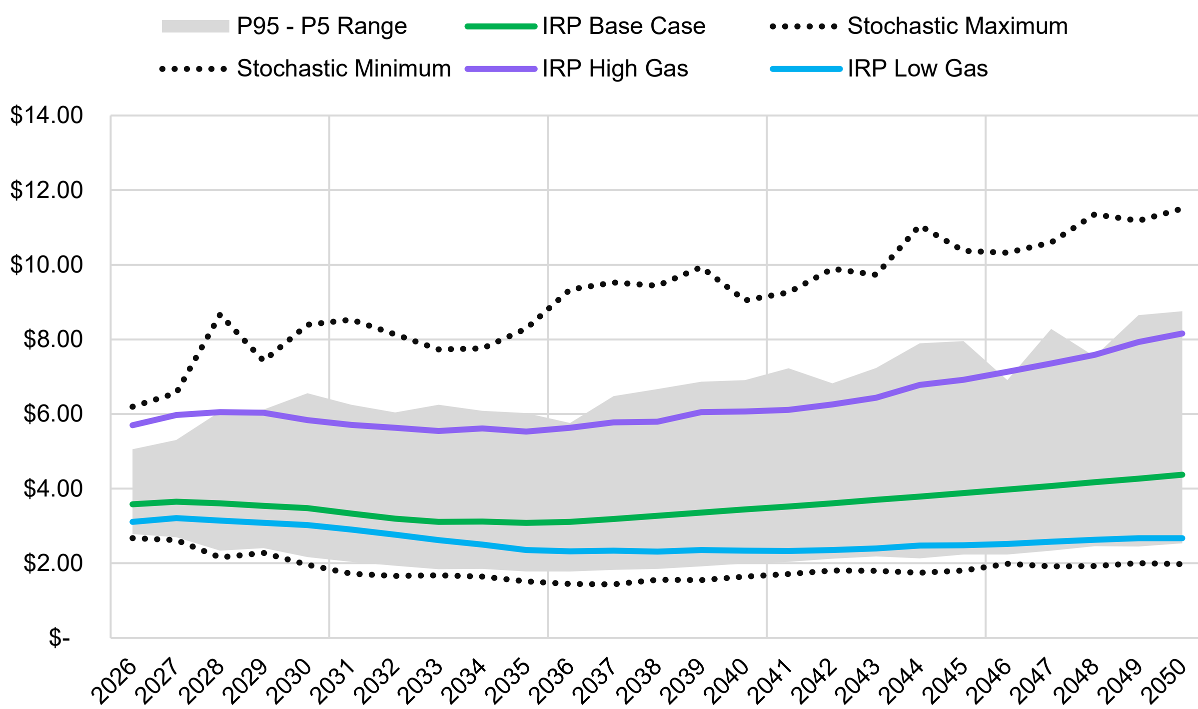


Figure 8-9: Henry Hub Natural Gas Prices – Deterministic and Stochastic Ranges (Nominal $/MMBtu)

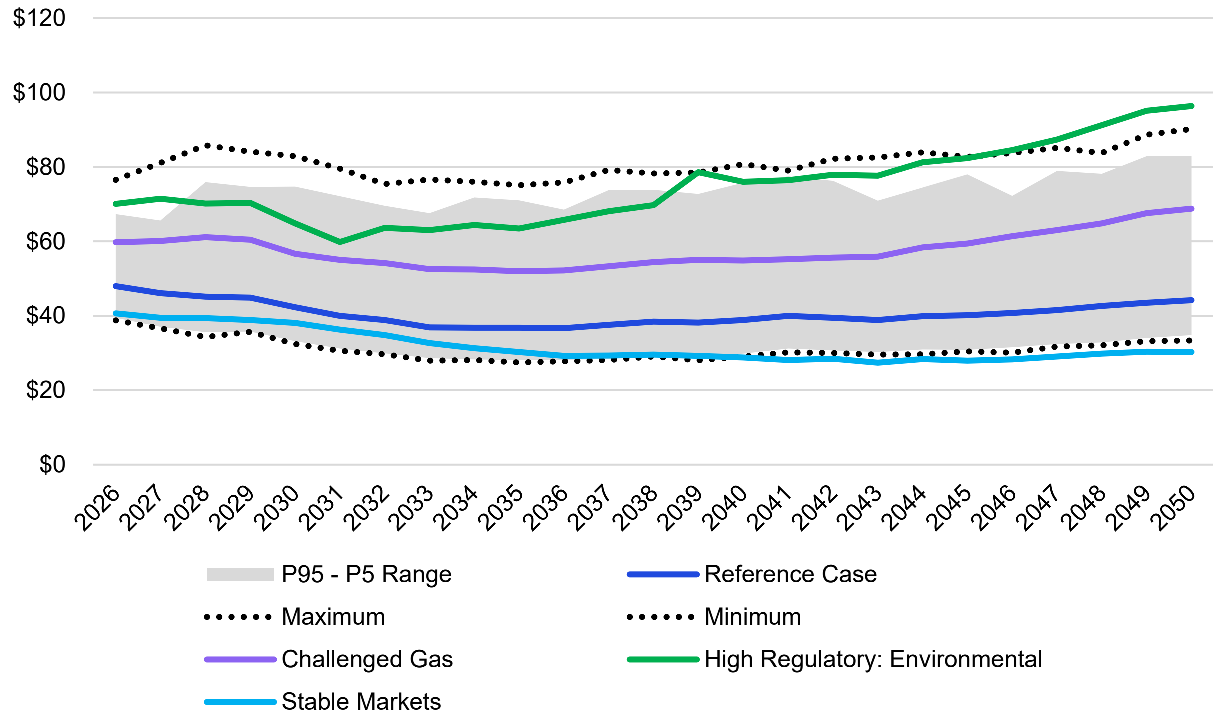


Power Prices

Power prices were produced for four scenarios, plus 100 draws of prices that varied at the hourly level, scaled back to the Reference Case prices. Additional details about the ACES forecasts, including generation mix by scenario, are available in the Stakeholder Meeting #2 presentation, in Attachment 1-2 of the 2025 IRP, and on the AES Indiana website[54]. Figure 8-10 shows the annual 7x24 MISO Indiana Hub power prices for all deterministic sensitivities, along with the price range resulting from the stochastic draws.

54 https://www.aesindiana.com/sites/aesvault.com/files/2025-07/AES-Indiana-Public-Advisory-Meeting-2-2025.pdf

Figure 8-10: MISO Indiana Hub 7x24 Power Prices – Deterministic and Stochastic Ranges (Nominal $/MWh)



Data Center Load: Modeling Details

As described in Section 6 (Load Forecast Section), three trajectories of generic data center load growth were modeled in the 2025 IRP, shown in Figure 8-11 below.

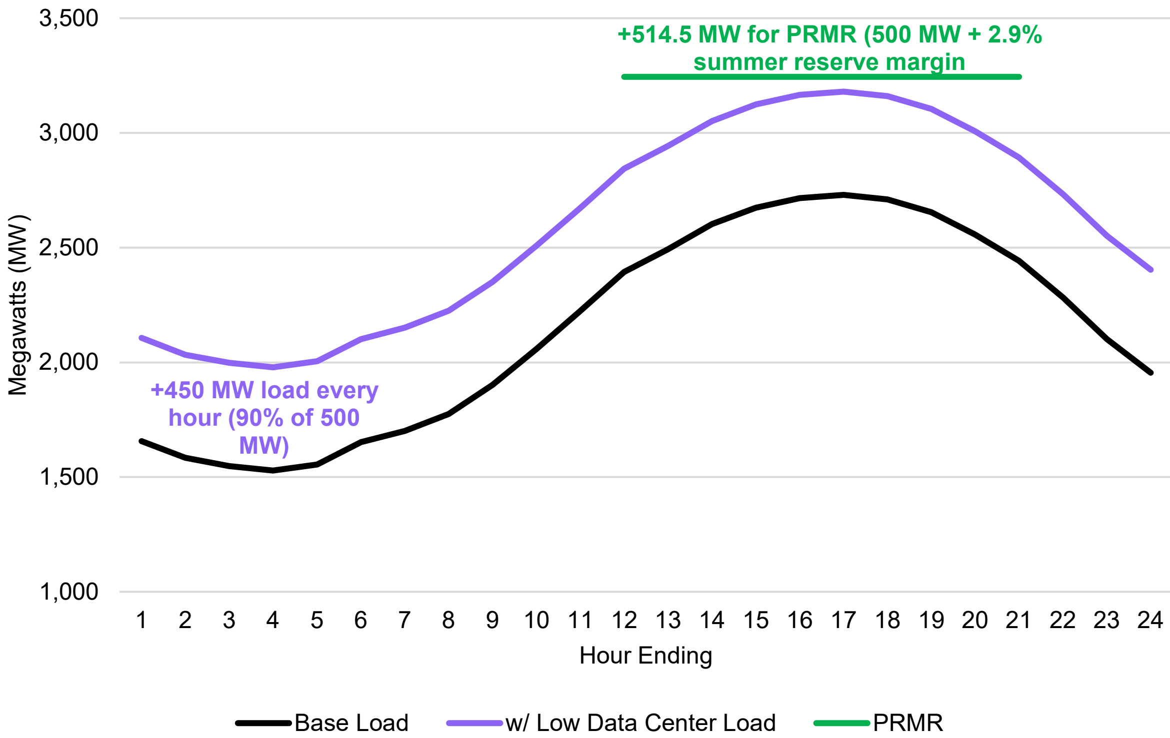
Figure 8-11: Annual Generic Data Center Load Additions (MW)

	Low	Mid	High
2027	0	50	75
2028	50	231	378
2029	114	413	681
2030	179	594	984
2031	243	775	1,288
2032	307	956	1,591
2033	371	1,138	1,894
2034	436	1,319	2,197
2035	500	1,500	2,500
2036	500	1,500	2,500
2037	500	1,500	2,500
2038	500	1,500	2,500
2039	500	1,500	2,500
2040	500	1,500	2,500

AES Indiana assumed the following for the data center load:

- Load Factor: the base load factor was assumed to be 90% for all seasons and years.
- Data center loads were modeled as a separate load item in EnCompass from the rest of the AES Indiana modeled load. Therefore, no stochastic variability was applied to the data center load.
- The 90% load factor was applied to all hours, so the hourly demand was 90% of the peak loads depicted in Figure 8-12. However, adjustments were made to the model so that firm capacity requirements by season were set to the full stated peak load. Figure 8-12 shows an example using the Low Data Center case. In the Low Data Center case for summer 2026, the data center load was assumed to be at a maximum of 500 MW. For every hour in the summer, the load profile was 450 MW for energy, but the reserve margin requirement was applied to the full 500 MW.

Figure 8-12: Example, Low Data Center Load – AES Indiana Load, Peak Summer Day



8.2.3 Iterative Capacity Expansion Portfolios for Load Scenarios

For the scenario matrix production cost model runs, AES Indiana made additional portfolio adjustments in five (5) scenarios to account for a higher load forecast. For example, the Reference Case portfolios were optimized to the Base Case AES Indiana load forecast (existing load with no data center load). As shown in Figure 8-13 below, the High Regulatory/Environmental scenario used the High Load case. Therefore, any Reference Case portfolios run through the High Regulatory/Environmental scenario would be short capacity. AES Indiana ran iterative capacity expansion runs to put the portfolios on equal footing.

Continuing with that example—the Reference Case, Mid Data Center Case portfolio was “locked in” or preset, and the iterative capacity expansion run built additional resources, optimized to the target scenario, to ensure that no portfolio was short of capacity.

Figure 8-14 below contains the additional winter firm capacity needed for the respective iterative capacity expansion runs.

Figure 8-13: AES Indiana Load in Scenarios

	Reference case	Gas infrastructure challenges (Scenario 2)	High regulatory: environmental (Scenario 3)	Stable markets scenario (Scenario 4)
AES Indiana load	Base	Base	↑	↓

Figure 8-14: Additional Winter Firm Capacity Needed in Scenario Matrix (Firm MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reference Case through Scenario 3	77	95	119	135	147	155	58	173	76	178	209	256	242	299
Scenario 2 through Scenario 3	77	112	119	135	(50)	(50)	(50)	(50)	47	145	170	212	244	296
Scenario 4 through Reference Case	23	23	69	135	180	72	122	210	87	168	176	197	208	220
Scenario 4 through Scenario 2	22	23	69	135	180	72	122	210	87	167	176	197	208	219
Scenario 4 through Scenario 3	77	89	146	224	280	183	245	349	245	340	363	403	434	469

8.3 Other Modeling Assumptions, Parameters, and Constraints

170 IAC 4-7-4(23) and 170 IAC 4-7-8(c)(3)

8.3.1 Capacity Expansion Setup and Constraints

Market Interaction

The EnCompass capacity expansion model optimizes for the least cost portfolio, co-optimizing capacity, energy, and any environmental constraints. As a MISO market participant, AES Indiana offers all units at cost and units clear based on locational marginal prices, which reflect the unit on the margin for the entire market, including local congestion and losses. If a unit does not clear, AES Indiana load can be purchased for less than the unit's cost, with the savings captured in energy market purchases. If cleared resources exceed the load in a given hour, that will be reflected in wholesale sales or off-system sales. In the IRP EnCompass model, the market LMPs are an input and do not change based on the resulting AES Indiana load or resource mix in the optimized portfolio. Because of this, the model will be indifferent to how the load is served, be it market purchases or owned/contracted resources. This can lead to large imbalances in the energy mix, with portfolios either relying on an outsized level of market purchases relative to produced energy or building to capture excess market sales.

To capture uncertainty and market depth of the MISO energy market over time, AES Indiana constrained market purchases and sales to 20% of the annual load. For the data center cases, the volume of market purchases and sales was anchored to the base, no data center load forecast. This is a conservative approach that reflects growing uncertainty about the depth and price levels for the energy market and LMPs as more data center load is added to the system.

Figure 8-15 below depicts the energy market constraints in the 2025 IRP for the No Data Center Reference Case and the Mid Data Center Reference Case. The gray-shaded area represents the 20% market constraint based on the Base Load Forecast, with no data center load. If the 20% constraint were applied to the full load in the Mid Data Center case, as depicted by the blue dotted lines, it would increase the permitted volume of market interaction. However, AES Indiana constrained the market interaction to match the volume of the No Data Center Case.

The result is an "effective" market interaction constraint that decreases as a percentage of load as more data centers are added to the system. Figure 8-16 shows the annual effective market interaction percentages by data center case.

While it is difficult to determine the ideal level of market interaction for a portfolio, the steps AES Indiana took to model and evaluate market purchases enhance the reliability of IRP modeling and provide a way to account for energy market uncertainty moving forward.

Figure 8-15: Illustrative Example of 20% Market Limits, Constrained in Data Center Cases

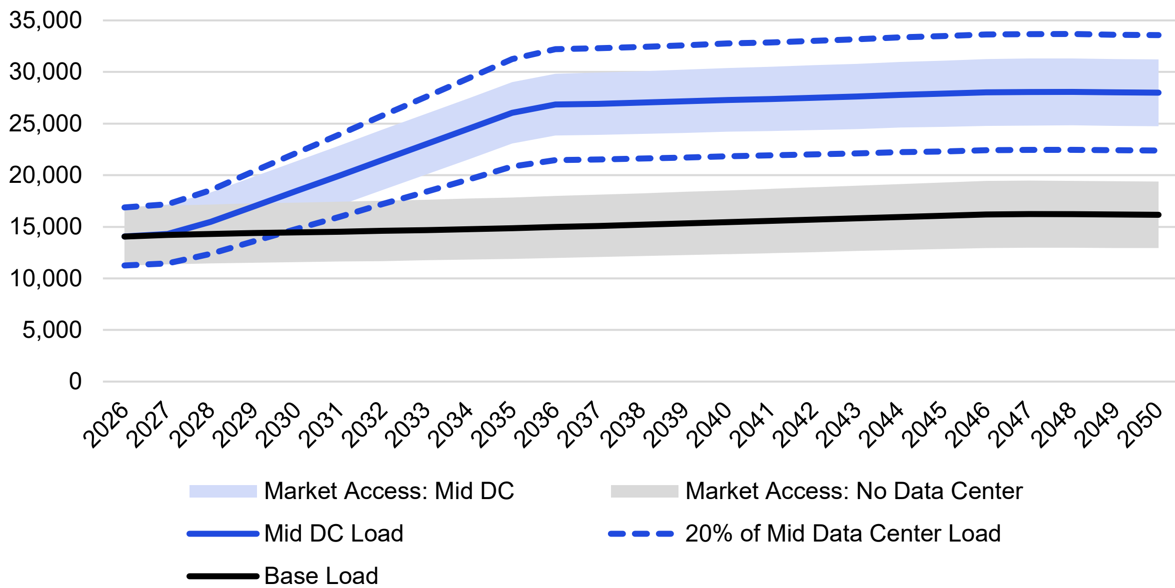
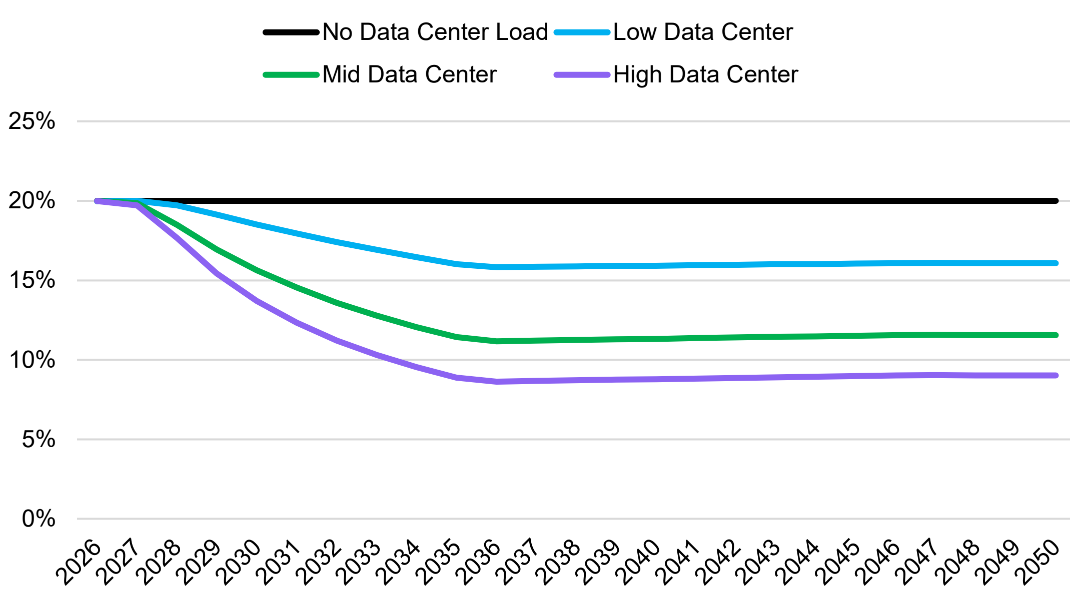


Figure 8-16: Effective Market Limits by Load Scenario (Annual %)



AES Indiana also constrained capacity market interaction in the 2025 IRP. The model was limited to 50 MW[55] of purchases and sales per capacity season, priced at MISO CONE. Capacity purchases are for a single year and are primarily used as a balancing mechanism, as the model is solving for the peak plus reserve margin requirement in the study. AES Indiana does not view any resulting capacity purchases or sales as definitive signals to pursue those transactions. Instead, the capacity market interaction indicates the binding season, and any Short-Term Action Plan would accommodate year-to-year changes in the prompt-year capacity position as MISO publishes final reserve margins and accreditation.

Build Limits by Technology

Selection of new resources was limited to:

1) prevent selecting near-term resources that cannot practically be executed or are not supported by recent RFP responses;

2) prevent selecting more resources than would be practical over the study period; and

3) prevent overreliance on a single resource type.

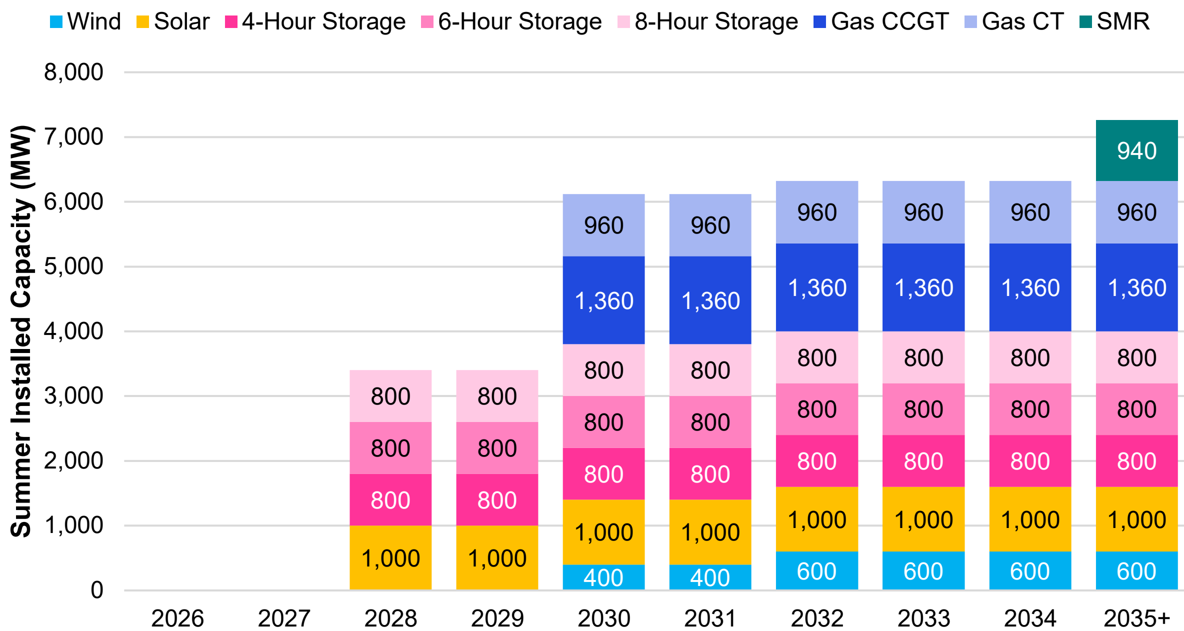
Figure 8-17 and Figure 8-18 demonstrate the total selectable capacity (ICAP) in each year of the IRP planning period. All new resource capacity limitations are represented in the summer installed capacity in MW.

Figure 8-17: 2025 IRP Annual Build Limits by Technology

	Per year limits (ICAP MW)										
Project Type	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035+**	***Planning Period Max (ICAP MW)***
Wind	0	0	0	0	400	400	600	600	600	600	8,000
Solar	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	8,000
4-Hour Storage	0	0	800	800	800	800	800	800	800	800	1,600
6-Hour Storage	0	0	800	800	800	800	800	800	800	800	1,600
8-Hour Storage	0	0	800	800	800	800	800	800	800	800	1,600
Gas CCGT	0	0	0	0	1,360	1,360	1,360	1,360	1,360	1,360	4,080
Gas CT	0	0	0	0	960	960	960	960	960	960	2,880
SMR	0	0	0	0	0	0	0	0	0	940	1,880

[55] Summer 2026 capacity limit was increased to allow for capacity coverage for the Petersburg Unit 4 conversion outage.

Figure 8-18: Annual Selectable Capacity (Summer ICAP)



8.4 Additional Scenarios and Sensitivities

170 IAC 4-7-4(26)

AES Indiana conducted seven (7) additional analyses as part of the 2025 IRP. These additional model runs were either scenarios or sensitivities. A scenario included a capacity expansion run to identify portfolio selection changes and the resulting production cost differences associated with a specific constraint or change to the resource selection parameters. A sensitivity analysis held the resource mix constant while varying a specific variable.

Two of these additional studies were initiated by AES Indiana, and stakeholders requested five. Figure 8-19 lists the additional studies, with full descriptions below the table.

Figure 8-19: Additional Scenarios and Sensitivities Performed for the 2025 IRP

	Name
AES Indiana initiated	1. Data center transmission investment
	2. SMR breakeven analysis
Stakeholder requested	3. Model ERAP instead of RAP for C&I
	4. Reinstate tax credits for wind and solar in the Reference Case
	5. Model a lower load factor for the data center load
	6. Model case where the data center load leaves early
	7. Modify thermal costs in the Stable Markets scenario to reflect higher near-term pricing

8.4.1 Data Center Transmission Investment

AES Indiana assumed a base level of transmission investment for each data center scenario. The base level was established from internal transmission planning estimates and information from MISO's MTEP and Expedited Project Review (EPR) studies. This level establishes a baseline, but each data center project would be subject to a significant amount of variability based on location, size, and other non-AES Indiana located loads trying to connect to the system over time. The transmission investment is intended to estimate the MISO network upgrades required and does not reflect direct-connect costs for new loads. It is assumed that direct connect costs are covered 100% up front by potential new loads.

The transmission assumption in $/kW was tied to the final load value for the data center case, meaning the load value assumed by the end of 2035. For example, in the Low Data Center case, the base level of transmission investment was set at $250/kW, multiplied by 500 MW (the data center load assumed by the end of 2035), for a total capital investment of $125M. The transmission investment was staged over three installation years: Year 1, Year 4, and Year 7. The transmission cost was assumed to be depreciated over 30 years.

Because of uncertainty in transmission costs for new large loads, AES Indiana conducted a transmission investment sensitivity analysis to better understand the risk and cost implications of different investment requirements. The Base Case was assumed at $250/kW. The Low Case was assumed at $100/kW, and the High Case was assumed at $500/kW.

Figure 8-20: Data Center Cases, Transmission Investment Assumptions

LOW Data Center Load		Transmission CAPEX ($000)		
	MW	**Base ($250/kW)**	**Low ($100/kW)**	**High ($500/kW)**
Year 1	167	$41,667	$16,667	$83,333
Year 4	167	$41,667	$16,667	$83,333
Year 7	167	$41,667	$16,667	$83,333
	500	**$125,000**	**$50,000**	**$250,000**

MID Data Center Load		Transmission CAPEX ($000)		
	MW	**Base ($250/kW)**	**Low ($100/kW)**	**High ($500/kW)**
Year 1	500	$125,000	$50,000	$250,000
Year 4	500	$125,000	$50,000	$250,000
Year 7	500	$125,000	$50,000	$250,000
	1,500	**$375,000**	**$150,000**	**$750,000**

HIGH Data Center Load		Transmission CAPEX ($000)		
	MW	**Base ($250/kW)**	**Low ($100/kW)**	**High ($500/kW)**
Year 1	833	$208,333	$83,333	$416,667
Year 4	833	$208,333	$83,333	$416,667
Year 7	833	$208,333	$83,333	$416,667
	2,500	**$625,000**	**$250,000**	**$1,250,000**

8.4.2 SMR Breakeven Analysis

Small modular reactors (SMRs) were modeled as a selectable resource in the 2025 IRP. As AES Indiana progressed through the IRP modeling, it was seen that a new SMR was not selected in any capacity expansion run, including all data center cases and environmental scenarios. Rather than conclude with that in the modeling, AES Indiana wanted to see what the breakeven capital cost would be for a new SMR. Changes in federal and state policy, public-private partnerships, corporate/end-user funding, and other commercial advancements in SMRs could drive down costs for AES Indiana and its customers. Understanding the breakeven cost can help AES Indiana plan for future studies as more information is gathered on SMR technology.

The breakeven analysis was conducted by "forcing on" a new SMR in the High Data Center cases in 2035 and re-running the capacity expansion to optimize the remaining capacity and energy needs. The High Data Center case was chosen because the volume of new load is high enough that the addition of a 470 MW SMR would not have a significant impact on resource decisions. Because the model is optimizing to a specific reserve margin, smaller resource needs can drive larger changes, thereby conflating the analysis of what is driving changes in total portfolio cost.

After the new SMR portfolio was run through capacity expansion, hourly production cost runs were run to understand the direct impacts of the annual revenue requirement on the optimized portfolio.

AES Indiana conducted SMR analyses in the Reference Case, the Challenged Gas, and the High Regulatory scenarios to understand how breakeven changes with macro-level policy and market fundamentals.

8.4.3 Enhanced RAP Scenarios

The CAC and EFG requested additional analysis around the Enhanced RAP ("ERAP") energy efficiency bundles. The request was for AES Indiana to model the selectable ERAP bundles, particularly for C&I, instead of the RAP. AES Indiana conducted capacity expansion runs for the Reference Case across all data center cases, allowing ERAP bundles to be selectable instead of RAP bundles.

8.4.4 Tax Credit Scenarios

Clean Grid Alliance requested additional modeling around the reinstatement of tax credits in the Reference Case. The goal was to determine the impact of the OBBBA on wind and solar, in particular, in the Reference Case. AES Indiana reinstated and extended the full tax credits for wind and solar in the Reference Case and re-ran capacity expansion for all four data center trajectories (No, Low, Mid, High).

8.4.5 Data Center Load Factor Sensitivities

AES Indiana assumed a 90% load factor for the base model runs, as described in Section 8.3.1. The flat 90% load factor throughout the year is a base level assumption for all modeling in the 2025 IRP. However, AES Indiana acknowledges that data center operations vary depending on use.[56] Additionally, since AES Indiana uses a $/MWh scorecard metric to reflect the average total system rate, a lower load factor would increase the $/MWh system rate because the same fixed costs are spread over a lower MWh volume. This has potential implications for how risk is identified, measured, and allocated if a data center comes online but does not operate as planned.

To conduct this analysis, AES Indiana fixed the portfolios that were optimized in the Reference Case for the Low, Base, and High data center cases. The load factor sensitivities reduced the load factor from 90% to 70%. The firm peak requirements, the fixed costs associated with new resources, and the transmission investment were all tied to the original data center load forecasts for each scenario.

8.4.6 Data Center Exit

Stakeholders requested a sensitivity analysis in which the data center either leaves early or does not show up as planned. To evaluate this, AES Indiana conducted a set of sensitivity analyses on the High Data Center Case, optimized under the Reference Case scenario.

Under the High Data Center portfolio, AES Indiana evaluated the $/MWh rate metric, assuming one of two cases:

1. The investments needed to support the data center for the 25-year period are in-service, but the load never takes service. This is an extreme scenario that has no customer protections in place at the time of the investments. It also assumes AES Indiana will continue to invest even though the load isn't there.
2. Investments needed to support the High Data Center case load are made through 2031, then no additional investments are made. This reflects a “re-balanced” approach in which AES Indiana recognizes that the load does not materialize and does not continue to build to support it beyond 2031.

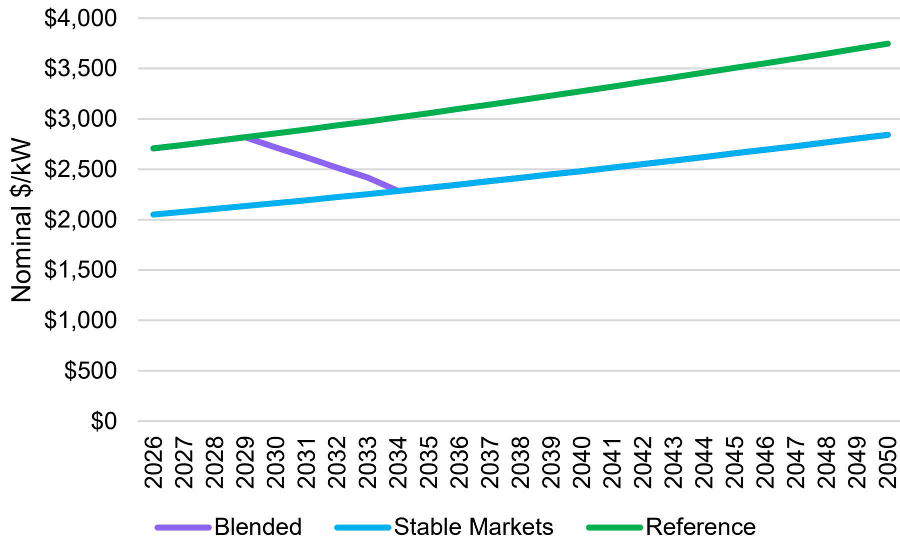
Under both cases, no customer protections are assumed to be in place. The goal is to estimate the potential risk if a data center does not materialize. The analysis can support the development of key customer protections and prudent capital investment planning as AES Indiana proceeds with any potential large load customer.

8.4.7 Stable Markets Scenario: Blended Capital Cost for New Resources

AES Indiana utilizes low capital costs for all new, selectable supply-side resources in the Stable Market scenario. The scenario is intended to capture how a lower-price environment, for both the cost of new resources and commodity prices (natural gas and power), would influence the optimal portfolio mix. Stakeholders requested modeling for a modified scenario that accounts for the documented recent increase in capital costs for new gas resources. AES Indiana created a “blended” Stable Markets scenario, in which capital costs remain the same as in the Reference Case through 2029 and are transitioned to Stable Markets costs over 5 years. Capacity expansion runs were then conducted for all four data center cases.

[56] https://www.powerpolicy.net/p/the-puzzle-of-low-data-center-utilization

Figure 8-21: CCGT Capital Cost in Blended Stable Market Scenario (Nominal $/kW)



8.5 Portfolio Metrics & Scorecard

AES Indiana compiled a comprehensive set of portfolio metrics that comprise the IRP Scorecard, which was used to evaluate the candidate portfolios and ultimately select the Company's Preferred Resource Portfolio and Short-Term Action Plan. The Scorecard uses a categorical framework to guide the Scorecard portfolio metrics. This framework was based upon the "Five Attributes or Pillars of Electric Utility Service" as defined by Indiana's 21st Century Energy Policy Development Task Force ("Task Force"):

These attributes or "pillars" are:

1. **Reliability** – Consisting of Adequacy and Operating Reliability.
    a. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonable expected unscheduled outages of system components.
    b. Operating Reliability is the ability of the electric system to withstand sudden disturbances such as electric circuits or unanticipated loss of system components.
2. **Resilience** is the ability of a system or its components to adapt to changing conditions, and to withstand and rapidly recover from disruptions.
3. **Stability** is the ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbance.
4. **Affordability** (to the customer).
5. **Environmental Sustainability**.

These five pillars guided AES Indiana's Scorecard metrics. In addition, the Company included an additional category of Risks and Opportunities. AES Indiana's 2025 IRP Scorecard includes a total of four categories (note that Reliability, Resilience, and Stability are combined into one):

1. Affordability;
2. Reliability, Resilience, and Stability;
3. Risks & Opportunities; and
4. Environmental Sustainability

The following section reviews the Scorecard portfolio metrics under each of these categories.

8.5.1 Affordability

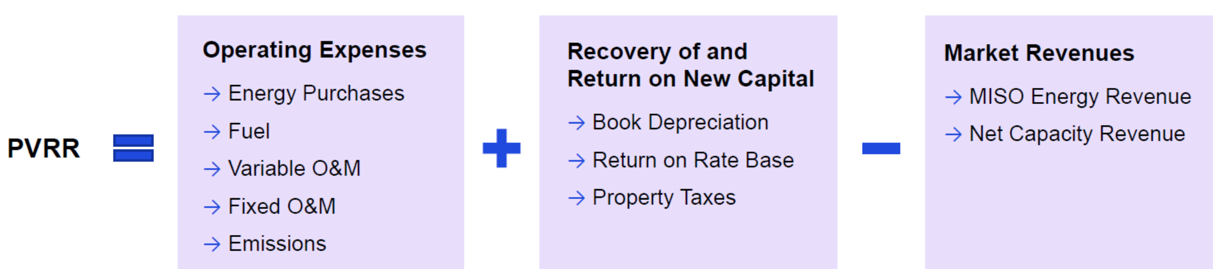
AES Indiana utilized two primary metrics for the affordability pillar:

1. Total system costs in $/MWh
    a. 10-year levelized
    b. 25-year levelized
    c. Annual system rate shown in results
2. Present Value of Revenue Requirements (PVRR)
    a. 10-year PVRR
    b. 25-year PVRR

Historically, best practice for the cost metric in IRPs has been PVRR, which captures the long-term economic impacts of portfolios over the planning period. The PVRR provides a holistic cost metric that captures all capital, operating, and market costs across different portfolios.

Figure 8-22 below provides the components and calculations of the PVRR. As described at the beginning of this section, AES Indiana used EnCompass for capacity expansion and hourly production cost modeling. Encompass provides the PVRR calculation as output from the hourly production cost analysis.

Figure 8-22: Revenue Requirement Components and Calculation



In the 2025 IRP, AES Indiana is evaluating new large loads as part of distinct but comparable capacity expansion portfolios. The varying levels of potential data center loads allow AES Indiana to plan for any future large load requests.

To meet the energy and capacity requirements of the new large loads, new resources need to be procured, existing units have the potential to run more, and/or reliance on the market could change as new loads are added to the system. As a result, the annual revenue requirement will always increase when a new load is added. This makes PVRR a challenging standalone metric because PVRRs cannot be compared across scenarios with different levels of load and resources.

Because of this, AES Indiana is using a system rate metric, expressed in dollars per megawatt-hour ($/MWh), in the 2025 IRP. The rate metric takes the annual revenue requirement divided by the total system sales. With this metric, comparisons can be made to determine system rate impacts and indicate rate pressures as more load and resources are added to AES Indiana's service territory.

There are several important considerations for the system rate metric:

What the IRP rate metric is intended to provide:

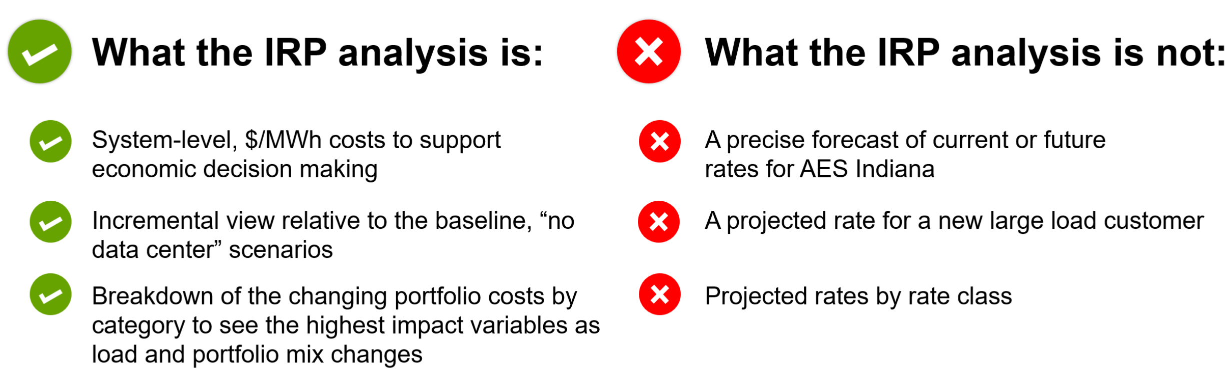
- → System-level, $/MWh costs to support economic decision making
- → Incremental view relative to the baseline, "no data center" scenarios
- → Breakdown of the changing portfolio costs by category to see the highest impact variables, such as load and portfolio mix changes.

What the IRP rate metric is not:

- × A precise forecast of current or future rates for AES Indiana.
- × A projected rate for a new large load customer
- × Projected rates by rate class

Figure 8-23 summarizes the intended purpose of the system rate metric.

Figure 8-23: Defining the Scope of the IRP System Rate Analysis



For the system cost metric, AES Indiana also incorporated the revenue requirement for existing generation, transmission, and distribution. Historically, AES Indiana has excluded these costs because they are assumed to be the same for all scenarios and portfolios. Only the incremental costs associated with new resources were considered. With the introduction of the system cost metric in $/MWh, it is important to capture the total system cost, inclusive of existing costs. AES Indiana used the revenue requirement details in Cause No. 46258[57] to provide a baseline revenue requirement. Revenue requirement for existing production assets, which includes depreciation, decommissioning, amortization, and return on in-service and approved/planned projects within the forward-looking test year. These costs were held constant throughout the study period. Transmission and distribution costs were escalated at 3% per year to estimate continued maintenance and O&M on assets. This baseline revenue requirement was added to all portfolios in all data center cases and scenarios.

Figure 8-24: Visual Depiction of Total Revenue Requirement with Baseline Existing Costs

			2026	2027	2028	2029	2030
		Existing Production Assets					
		Depreciation/Decommissioning Costs	$198	$198	$198	$198	$198
		Amortization	$65	$65	$65	$65	$65
		Return on	$338	$338	$338	$338	$338
	1	Total Existing Prod.	$601	$601	$601	$601	$601
	2	**Transmission & Distribution**	$777	$800	$824	$849	$874
Calc:1+2	3	**Baseline Revenue Requirement ($MM)**	**$1,378**	**$1,401**	**$1,425**	**$1,450**	**$1,475**

"Baseline" Annual Revenue Requirement
Starting values established from Cause No. 46258

Costs for existing production assets held flat
T&D, other costs escalated at 3% annually
** Baseline costs added to ALL portfolios **

			2026	2027	2028	2029	2030
		Expenses ($MM)	**814**	**811**	**827**	**819**	**811**
		Energy Purchases	115	106	100	87	119
		Fuel	367	438	431	436	390
		Variable O&M	131	128	129	131	131
		Fixed O&M	183	129	146	135	136
		Start Cost	2	1	1	1	1
		Demand Response and Energy Efficiency	0	9	15	25	31
		Capacity Purchases	17	1	3	1	1
		Emissions	1	1	1	1	1
		Book Depreciation	0	0	2	2	2
		Property Taxes	0	0	0	0	0
		Decommissioning	0	0	0	0	0
		Insurance	0	0	0	0	0
		Rate Base ($MM)	**0**	**0**	**27**	**24**	**21**
		Return on Rate Base	0	0	2	2	2
		Total Revenue Requirement	814	811	829	821	813
		Less: (revenues from energy and capacity)					
		Energy Revenue ($MM)	96	148	136	136	125
		Capacity Revenue ($MM)	2	4	4	4	4
	4	**Incremental Revenue Requirement ($MM)**	**716**	**660**	**690**	**681**	**683**
Calc: 3+4	5	**Total Revenue Requirement ($MM)**	**$2,094**	**$2,061**	**$2,115**	**$2,131**	**$2,159**

26

IRP modeling will calculate "incremental" revenue requirement, including:
→ Wholesale market interaction (market purchases, sales)
→ Capacity market purchases and sales
→ Production: Fuel, Variable O&M, Fixed O&M
→ New DR/EE costs
→ Recovery of and on new resources

Total Revenue Requirement will be used for rate analysis

For the system cost metric, the total revenue requirement was divided by total system sales to yield an annual revenue requirement in $/MWh. This metric, now normalized for both the revenue requirement and the annual load, allows for direct comparison of portfolios with and without new data center load.

While considering this metric, AES Indiana acknowledges that the system cost metric is not a perfect representation of how cost allocation would occur if a new load were to be added to the system. A full cost-of-service study or a similar cost allocation study would be required to analyze the cost impacts by customer class comprehensively. The IRP is intended to be a long-term

[57] On October 22, 2025, AES Indiana filed a partial settlement agreement with the IURC, establishing a revised revenue requirement ask for the forward-looking test year. The IRP analysis was completed and has not been revised to reflect changes reflected in the settlement agreement. AES Indiana does not believe there to be any material difference in the IRP analysis resulting from using revised numbers, as the revenue requirement change is less than 5% of the baseline total revenue requirement.

planning study, not a full rate analysis. AES Indiana would provide all customer rate impacts in a future regulatory filing with the IURC.

8.5.2 Reliability, Resilience, and Stability

AES Indiana took careful steps to evaluate reliability in the 2025 IRP. A key goal was to embed reliability into the modeling itself, assuring that portfolios are reliable across scenarios and time, rather than just reporting and measuring reliability after the fact.

Special consideration was given to incorporating conservative assumptions for accreditation, reserve margins, and market availability to build portfolios that can support existing and potential new loads.

Critical Reliability Components Embedded in Modeling for All Portfolios and Scenarios

- MISO DLOL Reserve Margins and Accreditation
- Seasonal capacity optimization reflecting MISO's reserve margin targets by season
- Market Interaction constraints in capacity expansion and hourly production cost runs
- Forced outage rates for all thermal resources
- Hourly production shapes for all renewable resources

Additional metrics were included to capture the relative reliability of the 16 candidate portfolios:

Metric 1: Market Interaction & Exposure

Due to hourly fluctuations in load, wholesale market prices, and unit availability, AES Indiana can be net long or short energy throughout the year, which, as a MISO market participant, is characterized as market purchases and market sales. AES Indiana moved market interaction from a risk metric in the 2022 IRP to a reliability metric in the 2025 IRP because of the potential for new large loads across the state and a tight Zone 6 capacity market reflecting tighter energy conditions over time. All other things equal, a portfolio that can time-match load and rely less on the market to serve load will be a more reliable portfolio that can serve the load for all hours of the year.

While there is no "correct" level of market interaction, this is a valuable metric for comparing the relative risk of portfolios and their ability to time-match hourly load across the year.

Metric 2: Dispatchable Capacity

A metric introduced in the 2025 IRP recognizes the role of dispatchable resources, particularly natural gas and battery storage, as critical reliability resources that support grid reliability, resiliency, and stability. AES Indiana's experience with local natural gas resources, along with newly developed and planned battery storage projects, shows that these resources benefit the system through a combination of flexible operations, quick-start capabilities, frequency regulation, and more. Additional reporting, research, and materials from NERC, MISO, the U.S. Department of Energy, the Indiana Office of Energy Development, and other third parties support, including dispatchable capacity, as defined by natural gas and battery storage resources, as a critical and comprehensive metric for this statutory pillar.

Overview of support for dispatchable resources as a reliability, resiliency, and stability metric in the 2025 IRP:

Figure 8-25: Findings and Support for Natural Gas and Battery Storage Contributions to Reliability, Resiliency, and Stability

Name	Finding
NERC 2024 Long-Term Reliability Assessment (Link)	"Natural-gas-fired generators are a vital BPS [Bulk Power Supply] resource. They provide ERSs [Essential Reliability Services][58] by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand."
NERC 2024 Long-Term Reliability Assessment (Link)	"Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs [Variable Energy Resources] in ERCOT and California where wind and solar make up a large portion of the resource mix."
Aurora Energy Research: "Battery energy storage impact and benefits assessments in MISO" (Link)	"Batteries play a multifaceted role within wholesale power markets, including contributions to reliability, system flexibility, ancillary services and a synergistic relationship with both renewable and thermal generation resources."
MISO Attribute Adequacy Panel, Presentation at OMS Annual Meeting (Link)	See Figure 8-26 below. Natural gas and battery resources are shown with their respective scoring relative to the following attributes: Capacity, Fuel Assurance, Long Duration at High Output, Voltage Stability, Ramp Up Capability, Rapid Start-Up, and Black Start Capability
U.S. Department of Energy, "Battery Energy Storage Systems Report" (Link)	"Batteries, particularly utility-scale batteries, provide a range of essential services to the power grid in the United States—services that are vital for maintaining the stability, efficiency, and reliability of the grid."
Indiana Office of Energy Development, "Utility-Scale Battery Energy Storage System Applications and Impacts in Indiana" (Link)	"This study finds that utility-scale BESS has strong potential to continue supporting Indiana's energy goals across all five statutory pillars."

[58] Essential Reliability Services:
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Figure 8-26: MISO - Reliability Attributes by Resource Type

	Rotating Machine				Inverter-based			Demand-Side[2]	
Attribute/Resource Type (illustrative list of attributes)	Coal	Gas	Nuclear	Hydro	Solar	Wind[1]	Battery	Load Control	Energy Efficiency
Capacity	●	●	●	◕	◔	◔	◕	◕	●
Fuel Assurance	◕	◑+	●	◕	◑	◔	◑	◔	●
Long Duration Energy at High Output	●	●	●	◕	◑	◑	◔	◔	●
Voltage stability	◕	◕	◕	◕	◑+	◑+	◑+	◔+	○
Ramp Up Capability	◕	●	◔	●	◔	◔	●	●	○
Rapid Start-Up	◑	●	◔	●	◑	◔	●	●	○
Black Start Capability	○	●	○	●	○+	○+	◑+	○	○

+ Attribute strength may **increase** in the future through technology advancements and/or standards development

[1] **Wind** power conversion technology has largely moved to Type 4 machines for new deployments, which are inverter-based, though deployed technology includes synchronous machines and doubly fed induction generator technologies, affecting characteristics.

[2] **Distributed Energy Resource** industry definitions often consist of 1) distributed generation, 2) distributed storage, 3) load control, and 4) energy efficiency. These are usually considered "**demand-side**" from the MISO perspective. For the above table, distributed storage and distributed generation are assumed to have characteristics consistent with bulk system resource counterparts (i.e., distributed battery and bulk system battery have same attributes) unless otherwise noted. Load Control and Energy Efficiency are called out separately.

[59]

Supplemental Modeling for Reliability, Resiliency, and Stability

AES Indiana hired Quanta to perform additional modeling related to reliability, resiliency, and stability metrics. This analysis provides additional support for the IRP, but the metrics are not included in the scorecard.

Quanta studied all 16 candidate resource portfolios for three distinct years: 2027, 2030, and 2035. This builds on the reliability study in the 2022 IRP, which analyzed 24 portfolios for just 1 year (2031).

Quanta performed an Essential Reliability Services (ERS) analysis, focusing on:

- Import/export analysis
- Energy adequacy
- Frequency (inertial and primary response)
- Short circuit strength

Additional details on the Quanta study can be found in Volume III.

8.5.3 Risks and Opportunities

In this IRP, AES Indiana considered both downside risk and upside opportunity to the Candidate Portfolios. Portfolio Risk and Opportunity were evaluated through three metrics: the impact of market and load volatility; risks associated with potential future environmental regulation; and how optimized portfolios perform across all scenarios, reflecting risk exposure to changing market conditions.

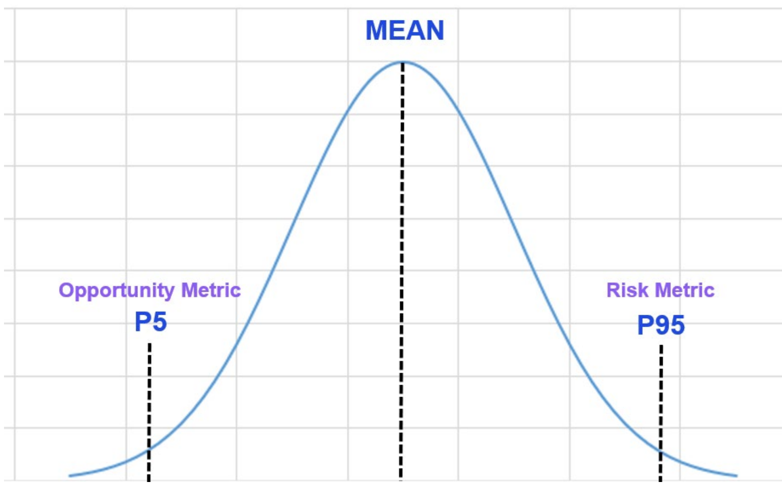
[59] https://www.misostates.org/images/stories/Attribute_Adequacy_Panel_-_OMS_Annual_Meeting_2022.pdf

Cost Risk and Opportunity Metric (Stochastic Analysis)

To evaluate general cost risk & opportunity to the candidate portfolios, AES Indiana used stochastic analysis to evaluate uncertainty in power prices, natural gas prices, load, and renewable energy generation. These distributions served as inputs into EnCompass for the stochastic production cost hourly dispatch runs over all 100 distributions.

For the Scorecard evaluation, AES Indiana included the PVRR 95th Percentile ("P95") as the risk metric and the PVRR Fifth Percentile ("P5") as the Opportunity metric for each candidate portfolio distribution. Figure 8-27 below provides a graphical example of the risk and opportunity metric calculations.

Figure 8-27: Risk and Opportunity Metric Calculations



Environmental Scenario Risk

While stochastic modeling can provide risk profiles for volatility in commodity prices and weather-driven changes to load and renewables, it does not capture the risk of policy changes or other one-time, systemic changes to market fundamentals. The deterministic scenarios provide valuable insight into that type of analysis. For this metric, AES Indiana wanted to measure the risk for future environmental policy specifically. For the Reference Case, Scenario 2, and Scenario 4 portfolios, the difference in PVRR to the optimized case was calculated for the High Regulatory: Environmental scenario. This represents the relative risk each portfolio faces from changes in federal policy on new greenhouse gas rules, tax credits, and other factors that make natural gas resources more expensive.

Cost Difference from Optimized Portfolio

The deterministic scenario analysis provides a view of how portfolios optimized under specific conditions and assumptions perform when the underlying assumptions change. The deterministic risk indicates not only how well the portfolios perform in the optimized case, but also how well they perform over time as the market changes. The relative risk of each portfolio can be assessed by calculating the percentage difference from the optimized case and averaging across the scenarios.

8.5.4 Environmental/Sustainability

Under the Environmental Sustainability category, AES Indiana included the following metrics:

- → Carbon Dioxide (CO_2) Emissions: Total Tons
    - Calculation: Total portfolio short tons of CO_2
- → Carbon Dioxide Emissions: Intensity
    - Calculation: Total portfolio pounds of CO_2 per MWh of load

Nitrous Oxide (NO_x) and Sulfur Dioxide (SO_2) emissions were modeled and are reported in Section 7.2.1 but are not part of the scorecard.

8.5.5 IRP Scorecard for Evaluation Portfolio Evaluation

Figure 8-28 provides the IRP Scorecard for evaluation, with categories and metrics for each category included.

Figure 8-28: IRP Scorecard Metrics – Summary

AFFORDABILITY	10-Year Levelized Supply Cost (2026$/MWh, 2025-2035)	Includes all system costs (depreciation/decommissioning on existing assets, amortization on existing assets, return on existing assets, and transmission/distribution expenses) and incremental revenue requirements, divided annually by total retail sales; then levelized
	25-Year Supply Cost (2026$/MWh, 2026-2050)	
	10-Year PVRR (2026$MM, 2026-2035)	Incremental annual present value revenue requirements then levelized; ignores sunk costs
	25-Year PVRR (2026$MM, 2026-2050)	
RELIABILITY, RESILIENCY, AND STABILITY	25-year Market Interaction: Purchases + Sales	Sum of two metrics below
	25-year energy purchases	Average of annual energy purchases divided by retail sales across study period (2026-2050)
	25-year energy sales	Average of annual energy sales divided by retail sales across study period (2026-2050)
	Dispatchable Capacity Divided by Peak Load (2035)	In 2035, total dispatchable (natural gas and storage) capacity divided by peak load
	Dispatchable FIRM Capacity Divided by Peak Load (2035)	In 2035, total firm dispatchable (natural gas and storage) capacity divided by peak load
RISK & OPPORTUNITY	(Mean – P5)	Across 100 stochastic runs, the mean minus the 5th percentile value of the 25-Year PVRR (2026$MM, 2026-2050)
	(P95 – Mean)	Across 100 stochastic runs, the 95th percentile value minus the mean of the 25-Year PVRR (2026$MM, 2026-2050)
	Opportunity: % of PVRR	The (Mean – P5) metric divided by the 25-Year PVRR (2026$MM, 2026-2050)
	Risk: % of PVRR	The (P95-Mean) metric divided by the 25-Year PVRR (2026$MM, 2026-2050)
	Environmental Scenario Risk	The 25-Year PVRR (2026$MM, 2026-2050) of the "High Environmental: Regulatory" Scenario minus the evaluated Scenario
	Mean PVRR % Difference from Optimal	The average percent difference between the evaluated Scenario and the optimized Portfolio
ENVIRONMENTAL	Total CO_2 Emissions (Million Tons)	Generation emissions across study period (2026-2050)
	Total CO_2 Emissions (lb/MWh, Study Average)	Sum of total CO_2 emissions across study period (2026-2050) divided by total retail sales across study period (2026-2050)

Section 9: IRP Results

170 IAC 4-7-4(24), 170 IAC 4-7-4(25), 170 IAC 4-7-8(a), 170 IAC 4-7-8(b)(1), 170 IAC 4-7-8(c)(4), and 170 IAC 4-7-8(c)(8)

9.1 Executive Summary

170 IAC 4-7-4(8)

To select the Preferred Resource Portfolio and Short-Term Action Plan in this IRP, AES Indiana:

5. Optimized four different large load profiles across four different scenarios. A total of 16 portfolios, or unique resource mixes, were created. These portfolios were frozen and run through all four scenarios, resulting in 64 model runs. This scenario analysis allowed portfolio performance across a range of policy and commodity futures to be considered. The results were represented and evaluated using a Portfolio Matrix. See Section 8.4 for details on the assumptions used in this analysis.
6. Completed additional sensitivities to respond to stakeholder questions.
7. Took the optimized portfolios and evaluated them using a Scorecard framework with four metric categories, including:
    a. Affordability;
    b. Sustainability;
    c. Reliability, Resiliency, and Stability; and
    d. Risk and Opportunity

    See Section 8.5 for details on the Scorecard evaluation framework.
8. Utilized the results from the Scorecard framework to select the Preferred Resource Portfolio and Short-Term Action Plan.

This section provides an evaluation of the results from the Scenario Analysis (Section 9.2), the additional Sensitivity Analysis, and the Scorecard (Section 9.3). It concludes with a review of the Preferred Resource Portfolio (Section 9.5) selected through the evaluation process.

9.2 Portfolio Creation

170 IAC 4-7-4(8), 170 IAC 4-7-4(25), and 170 IAC 4-7-4(26)

9.2.1 Overview

AES Indiana's 2022 IRP was a scenario analysis that included five generation strategies for the Petersburg Generating Station and a sixth analysis that allowed the model to optimize coal retirement and replacement. The retirement and replacement modeling framework optimized the strategies described above across four scenarios that varied in terms of environmental policy, commodity, and load assumptions.

The 2025 IRP is markedly different from the 2022 IRP. Unlike the 2022 IRP, the 2025 IRP is not a retirement analysis. Instead, the focus of the 2025 IRP is on possible large load integration. AES Indiana has experienced interest in large loads within the service territory; however, it is unknown at this time what the scale or timing could be.

Therefore, to prepare for a range of uncertain load futures, AES Indiana optimized four alternative load scenarios: no data center, low data center, high data center, and mid data center. Please see Figure 9-1 for a summary.

Figure 9-1: Data Center Loads (Peak in MW By End of Calendar Year)

	Low	Mid	High
2027	0	50	75
2028	50	231	378
2029	114	413	681
2030	179	594	984
2031	243	775	1,288
2032	307	956	1,591
2033	371	1,138	1,894
2034	436	1,319	2,197
2035+	500	1,500	2,500

These four load scenarios were optimized across four unique scenarios. The scenarios represent different world views. See Figure 0-2 for a summary of scenario assumptions.

Figure 9-2: Summary of Scenario Assumptions

Scenario Driver ↓	Reference case	Gas infrastructure challenges	High regulatory: environmental	Stable markets scenario
EPA GHG NSPS	Repealed	Repealed	111B remains in effect	Repealed
Tax credits (ITC/PTC)	OBBBA	OBBBA	IRA reinstatement + extension	OBBBA
AES Indiana load	Base	Base	↑	↓
Natural gas prices	Base	↑	↑	↓
Thermal CAPEX	Base	Base[1]	↑	↓
Renewables CAPEX	Base	Base	Base	↓
EV/distributed solar	↓	Base	↑	Base

The sixteen portfolios (four data center loads across four scenarios) were locked and run through each scenario, for a total of 64 model runs. See Figure 9-3 for a summary.

Figure 9-3: Model Run Matrix

		Scenarios			
No Data Center Load	Portfolios ↓	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
No Data Center Load	Reference Case	**Portfolio**	*Scenario*	*Scenario*	*Scenario*
No Data Center Load	Gas Infrastructure Challenges	*Scenario*	**Portfolio**	*Scenario*	*Scenario*
No Data Center Load	High Regulatory: Environmental	*Scenario*	*Scenario*	**Portfolio**	*Scenario*
No Data Center Load	Stable Markets Scenario	*Scenario*	*Scenario*	*Scenario*	**Portfolio**
Low Data Center Load		Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Low Data Center Load	Reference Case	**Portfolio**	*Scenario*	*Scenario*	*Scenario*
Low Data Center Load	Gas Infrastructure Challenges	*Scenario*	**Portfolio**	*Scenario*	*Scenario*
Low Data Center Load	High Regulatory: Environmental	*Scenario*	*Scenario*	**Portfolio**	*Scenario*
Low Data Center Load	Stable Markets Scenario	*Scenario*	*Scenario*	*Scenario*	**Portfolio**
Mid Data Center Load		Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Mid Data Center Load	Reference Case	**Portfolio**	*Scenario*	*Scenario*	*Scenario*
Mid Data Center Load	Gas Infrastructure Challenges	*Scenario*	**Portfolio**	*Scenario*	*Scenario*
Mid Data Center Load	High Regulatory: Environmental	*Scenario*	*Scenario*	**Portfolio**	*Scenario*
Mid Data Center Load	Stable Markets Scenario	*Scenario*	*Scenario*	*Scenario*	**Portfolio**
High Data Center Load		Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
High Data Center Load	Reference Case	**Portfolio**	*Scenario*	*Scenario*	*Scenario*
High Data Center Load	Gas Infrastructure Challenges	*Scenario*	**Portfolio**	*Scenario*	*Scenario*
High Data Center Load	High Regulatory: Environmental	*Scenario*	*Scenario*	**Portfolio**	*Scenario*
High Data Center Load	Stable Markets Scenario	*Scenario*	*Scenario*	*Scenario*	**Portfolio**

9.2.2 Candidate Portfolio Summaries

170 IAC 4-7-4(8), 170 IAC 4-7-8(b)(1), 170 IAC 4-7-8(b)(3), and 170 IAC 4-7-8(c)(5)

This section provides the Portfolio summaries for all four data center cases (no, low, mid, and high) as follows:

1) Reference Case

a. Installed capacity
b. Firm capacity
c. Energy mix
d. DSM selections

2) *Gas Infrastructure Challenges*

a. Installed capacity
b. Firm capacity
c. Energy mix
d. DSM selections

3) *High Regulatory: Environmental*

a. Installed capacity
b. Firm capacity
c. Energy mix
d. DSM selections

4) *Stable Market*

a. Installed capacity
b. Firm capacity
c. Energy mix
d. DSM selections

The following resource additions, conversions, and retirements are present in all portfolios shown:

Planned Conversions/Additions

- → Pete 3 (526 MW): In-service on gas June 2026
- → Pete 4 (526 MW): In-service on gas December 2026
- → Pete Energy Center: In-service December 2025
  - 250 MW Solar + 45 MW 4-hour BESS
- → Crossvine: In-service May 2027
  - 85 MW Solar + 85 MW 4-hour BESS

Retirements

Harding Street

- → HS ST5 Natural Gas (100 MW): 2041
- → HS ST6 Natural Gas (98 MW): 2041
- → HS ST7 Natural Gas (420 MW): 2041
  - **Total Nat Gas Retired MW: 618 MW**
- → Lakefield Wind PPA Expiration (200 MW): 10/31/2032

Iterative Capacity Expansion Adjustments

As described in Section 8.4.3, AES Indiana conducted a set of "iterative" capacity expansion runs to account for portfolios that are underbuilt when run through the other scenarios with high AES Indiana load (not specific to data centers). This process resulted in 20 additional capacity expansion runs, locking in the original optimized portfolio and re-optimizing to fill capacity needs when run through other scenarios.

In the portfolio scorecard and metrics, these portfolios serve as the underlying portfolios when comparing results to an optimized scenario. This process provides a more precise comparison when comparing cost and risk across portfolios and scenarios.

Figure 9-4: Iterative Capacity Expansion Runs – Cumulative Installed Capacity Changes through 2035

		DR	EE	Storage	Gas CCGT	Gas Peaking	Solar	Wind
No Data Center Load	Reference through Scenario 3	0	0	60	0	0	100	800
	Scenario 2 through Scenario 3	0	0	60	0	0	50	900
	Scenario 4 through Scenario 1	136	0	100	0	0	0	0
	Scenario 4 through Scenario 2	110	0	60	0	54	50	0
	Scenario 4 through Scenario 3	136	0	180	0	0	125	650
Low Data Center Load (500 MW)	Reference through Scenario 3	5	0	60	0	0	50	550
	Scenario 2 through Scenario 3	0	0	100	0	0	75	150
	Scenario 4 through Scenario 1	0	0	180	0	54	0	0
	Scenario 4 through Scenario 2	5	0	100	0	108	75	0
	Scenario 4 through Scenario 3	5	0	180	0	0	25	1,200
Mid Data Center Load (1,500 MW)	Reference through Scenario 3	19	0	80	0	0	625	350
	Scenario 2 through Scenario 3	0	0	40	0	0	250	500
	Scenario 4 through Scenario 1	0	0	240	0	54	0	0
	Scenario 4 through Scenario 2	0	0	180	0	54	75	0
	Scenario 4 through Scenario 3	0	0	120	0	0	150	1,650
High Data Center Load (2,500 MW)	Reference through Scenario 3	0	0	40	0	0	1,050	600
	Scenario 2 through Scenario 3	0	0	40	0	0	425	400
	Scenario 4 through Scenario 1	0	0	560	0	0	0	0
	Scenario 4 through Scenario 2	0	0	420	0	0	475	0
	Scenario 4 through Scenario 3	0	0	200	0	0	950	800

Reference Case Results

Figure 9-5 contains cumulative installed capacity volumes in 2030, 2035, 2040, and 2045 for all four data center cases run through the Reference Case.

Figure 9-5: Reference Case – Installed Capacity (MW) by Resource Type and Load Case

		2030	2035	2040	2045
Demand Response	No Data Center Load	186	223	225	224
	Low DC Load	184	218	219	217
	Mid DC Load	178	200	200	199
	High DC Load	184	218	219	217
Energy Efficiency	No Data Center Load	98	191	267	303
	Low DC Load	98	191	267	303
	Mid DC Load	98	191	267	303
	High DC Load	98	191	267	303
Battery Storage	No Data Center Load	20	100	100	100
	Low DC Load	160	420	420	420
	Mid DC Load	580	860	860	860
	High DC Load	620	640	680	680
Gas CCGT	No Data Center Load				700
	Low DC Load				700
	Mid DC Load		700	700	1,400
	High DC Load	700	2,100	2,100	2,800
Gas CT	No Data Center Load				
	Low DC Load		480	480	480
	Mid DC Load		480	720	720
	High DC Load		240	720	720
Gas Reciprocating Engines	No Data Center Load			108	108
	Low DC Load			54	54
	Mid DC Load			108	108
	High DC Load		54	54	54
Solar	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				
Wind	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				

Demand response and energy efficiency are similar across varying levels of large load additions; they are the resources of choice to serve native load growth within the AES Indiana service territory. While gas resources are available by 2030, battery storage and demand response are available by 2027. Therefore, capacity needs before 2030 are met by demand response and battery storage. Generally, the greater the load, the greater the additions of battery storage. By 2030, battery storage additions range from 20 MW to 620 MW. Data center load of 984 MW by

2030, or 1.5 GW by 2035, shows selections of new CCGTs. Additional CTs will be online by 2030 to support data center load. Reciprocating engines may be brought online after 2035 to meet incremental demand for large loads.

The cumulative installed capacity across scenarios is shown in Figure 9-6 through Figure 9-9. Without additional large loads, portfolio additions focus on demand response and energy efficiency.

The near-term installed capacity additions, by year, required for the various scenarios are shown in Figure 9-10 through Figure 9-13. The view provides additional granularity on selections from earlier years of the study, which could serve as a possible foundation for the short-term action plan.

Figure 9-6: Reference Case – No Data Center Load – Cumulative Installed Capacity (MW)

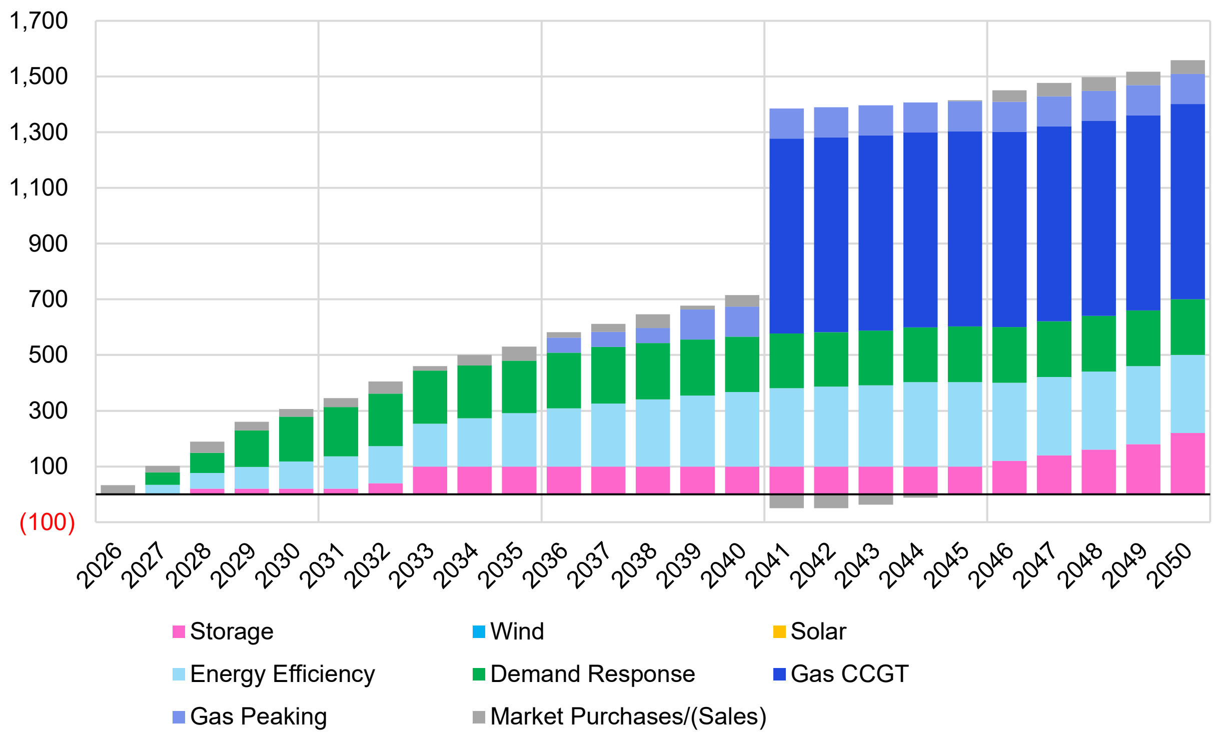


Figure 9-7: Reference Case – Low Data Center Load – Cumulative Installed Capacity (MW)

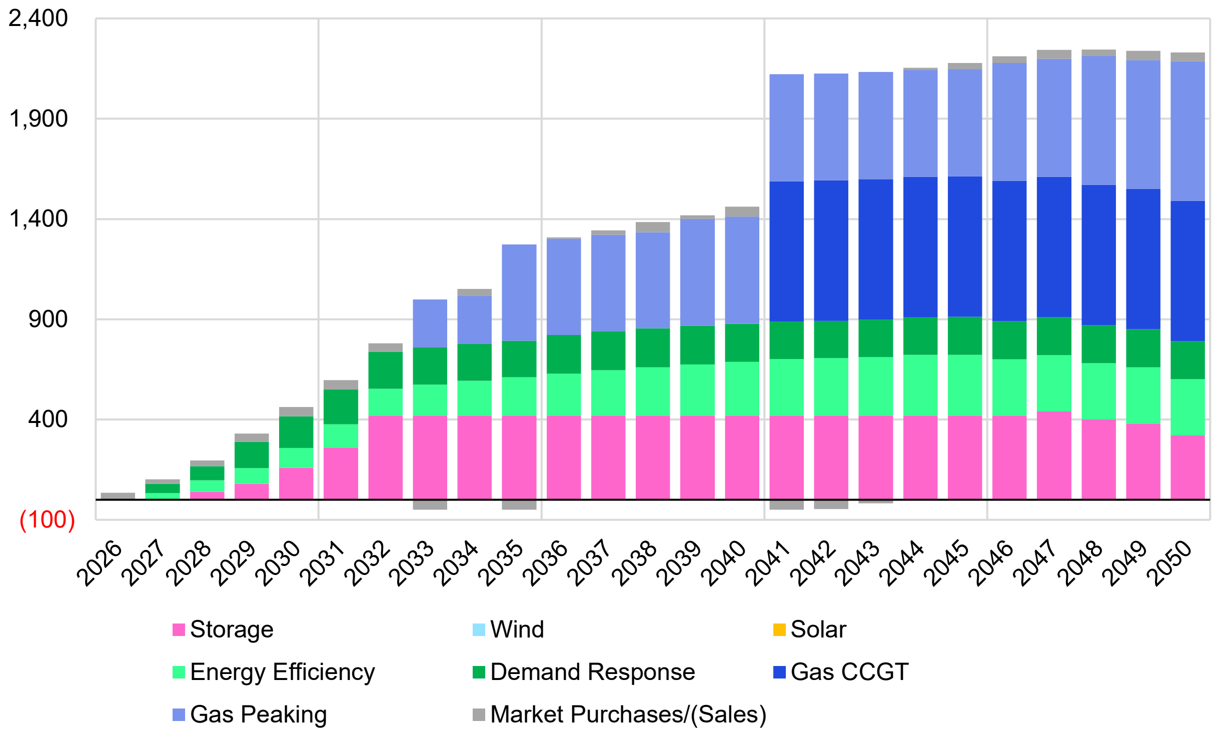


Figure 9-8: Reference Case – Mid Data Center Load – Cumulative Installed Capacity (MW)

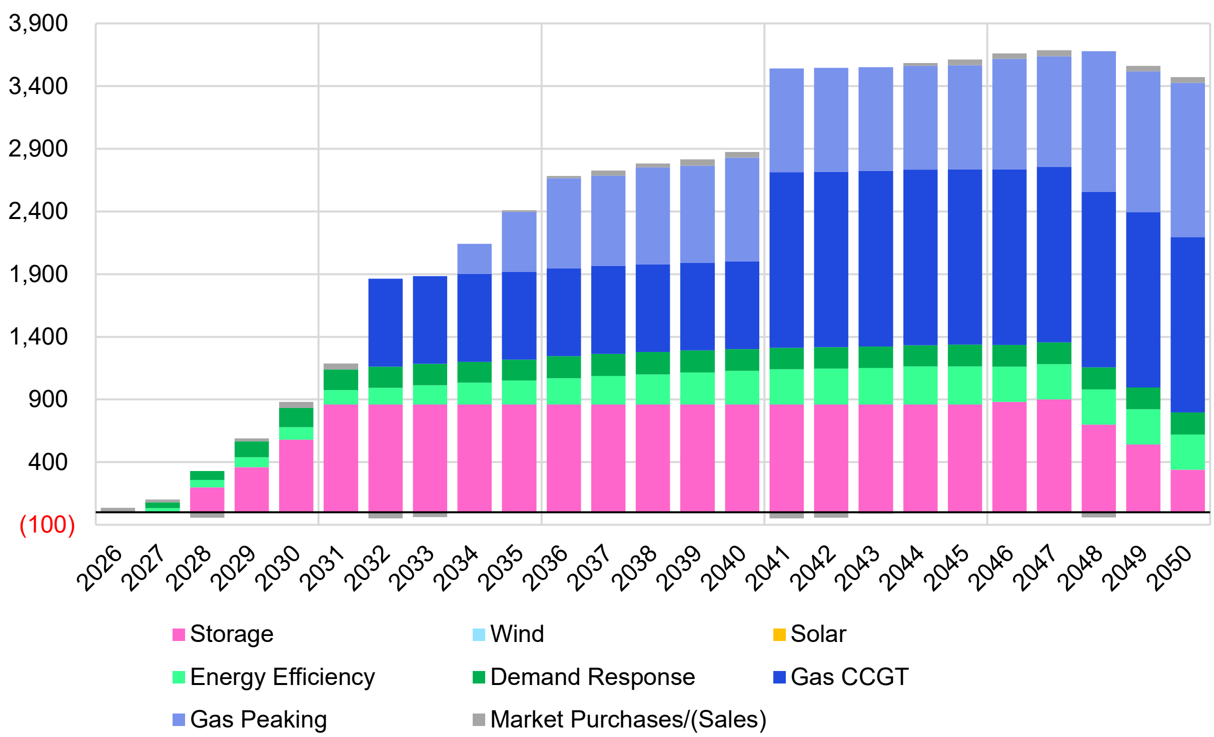


Figure 9-9: Reference Case – High Data Center Load - Cumulative Installed Capacity (MW)

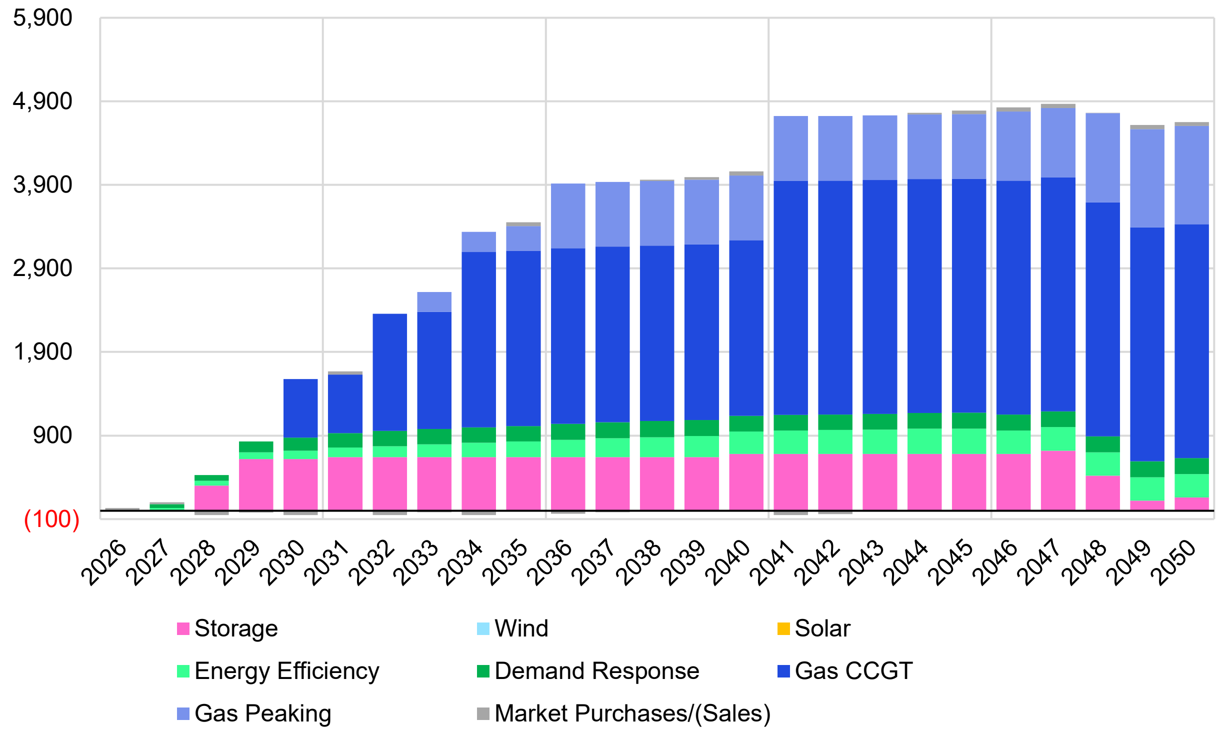


Figure 9-10: Reference Case – No Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		20	20	20	20	40	100	100	100
Gas CCGT									
Gas CT									
Gas Reciprocating Engines									
Solar									
Wind									

Figure 9-11: Reference Case – Low Data Center – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	152	184	204	214	216	217	218
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		40	80	160	260	420	420	420	420
Gas CCGT									
Gas CT							240	240	480
Gas Reciprocating Engines									
Solar									
Wind									

Figure 9-12: Reference Case – Mid Data Center – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	150	178	190	197	198	198	200
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		200	360	580	860	860	860	860	860
Gas CCGT						700	700	700	700
Gas CT								240	480
Gas Reciprocating Engines									
Solar									
Wind									

Figure 9-13: Reference Case – High Data Center – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	152	184	204	214	216	217	218
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		300	620	620	640	640	640	640	640
Gas CCGT				700	700	1,400	1,400	2,100	2,100
Gas CT							240	240	240
Gas Reciprocating Engines									54
Solar									
Wind									

Figure 9-14: Reference Case – No Data Center Load – Winter Firm Capacity (MW)

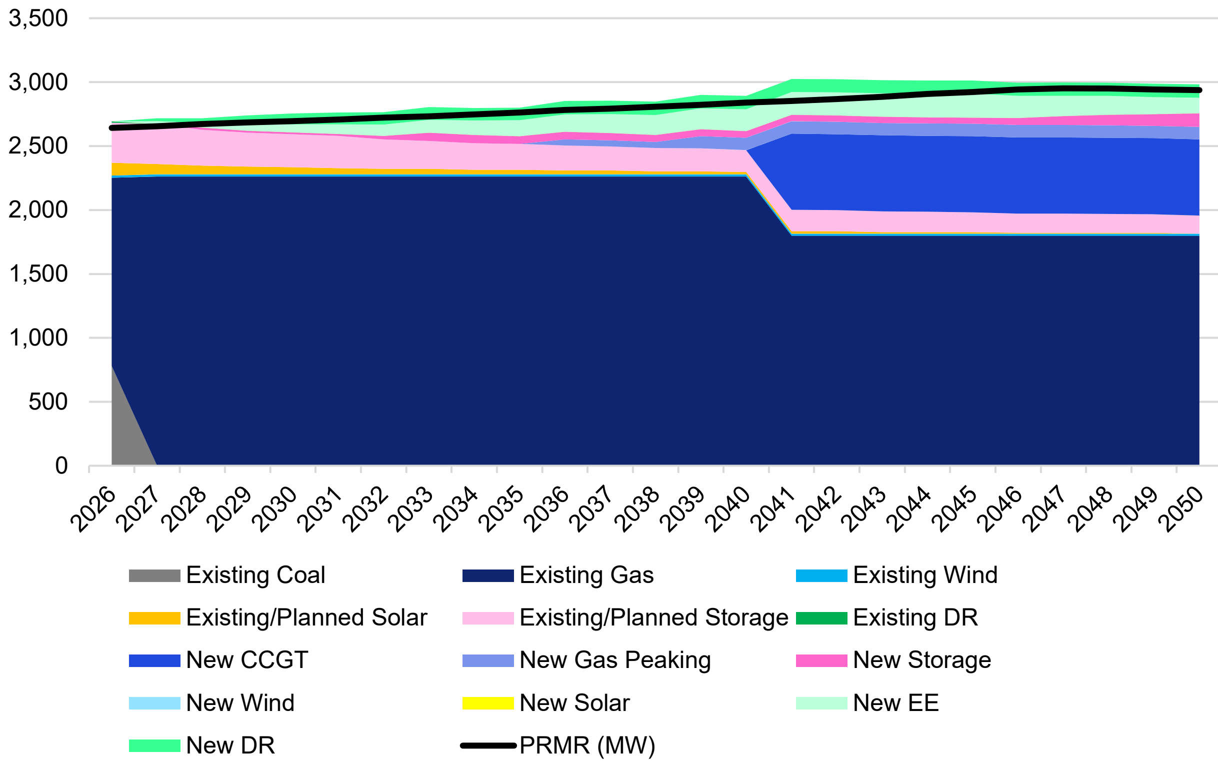


Figure 9-15: Reference Case – Low Data Center Load – Winter Firm Capacity (MW)

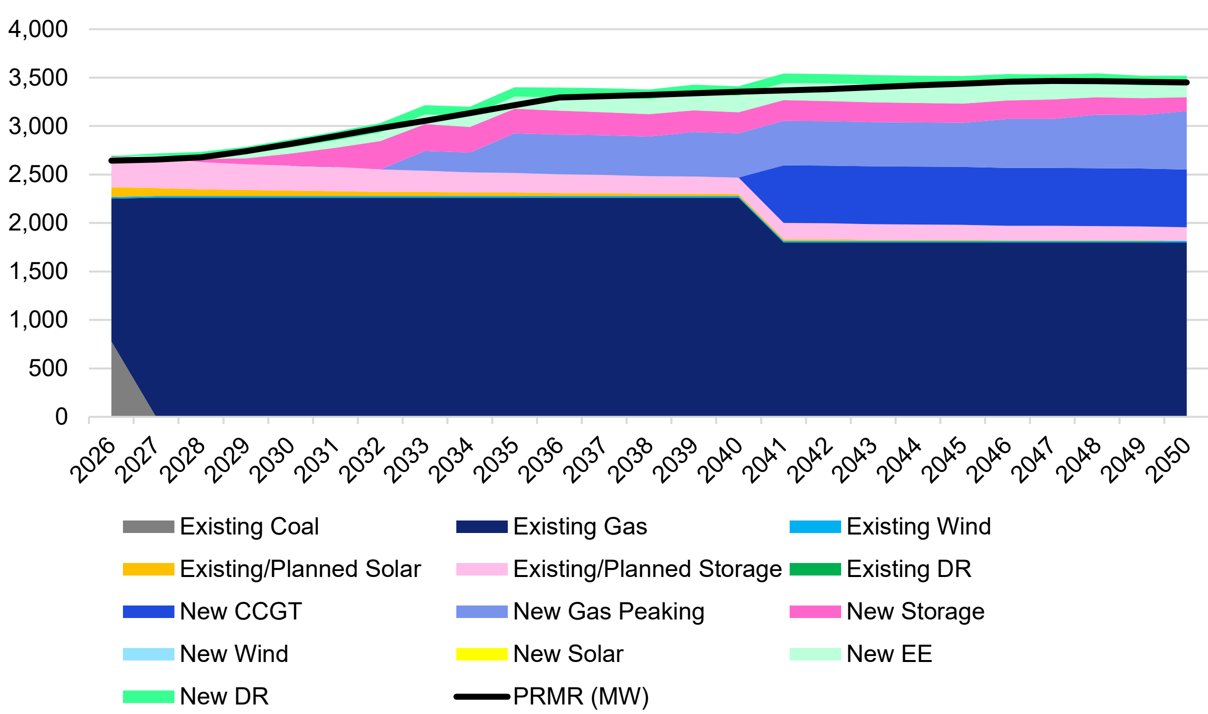


Figure 9-16: Reference Case – Mid Data Center Load – Winter Firm Capacity (MW)

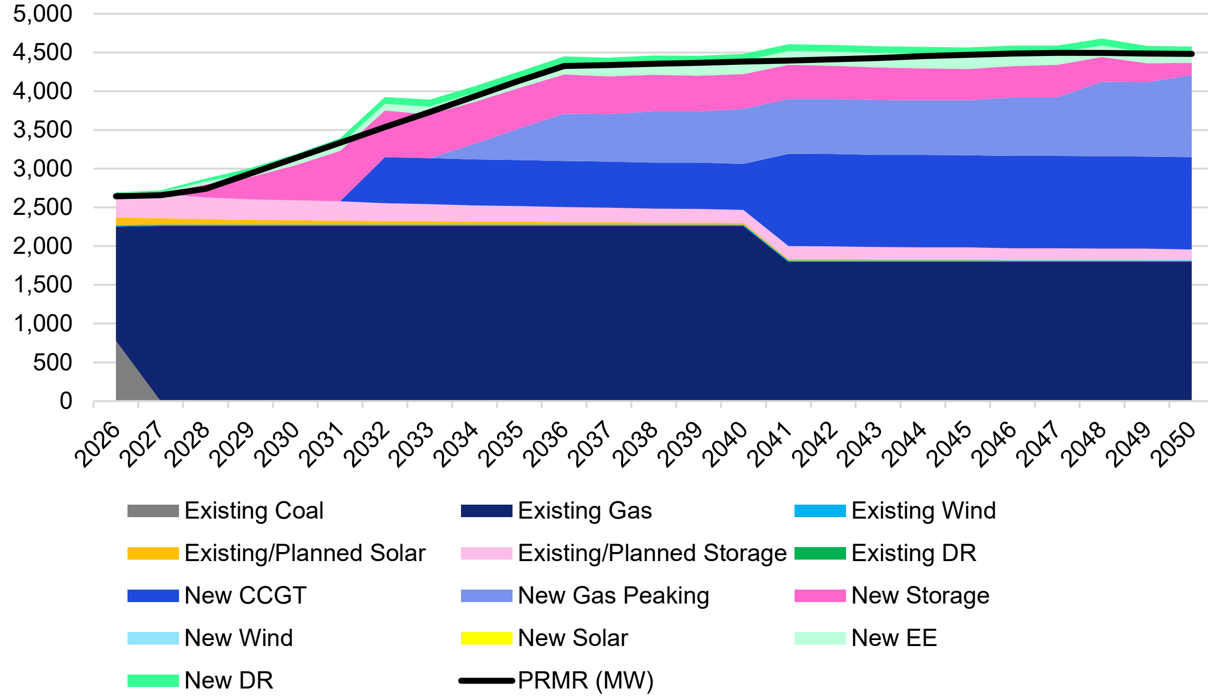
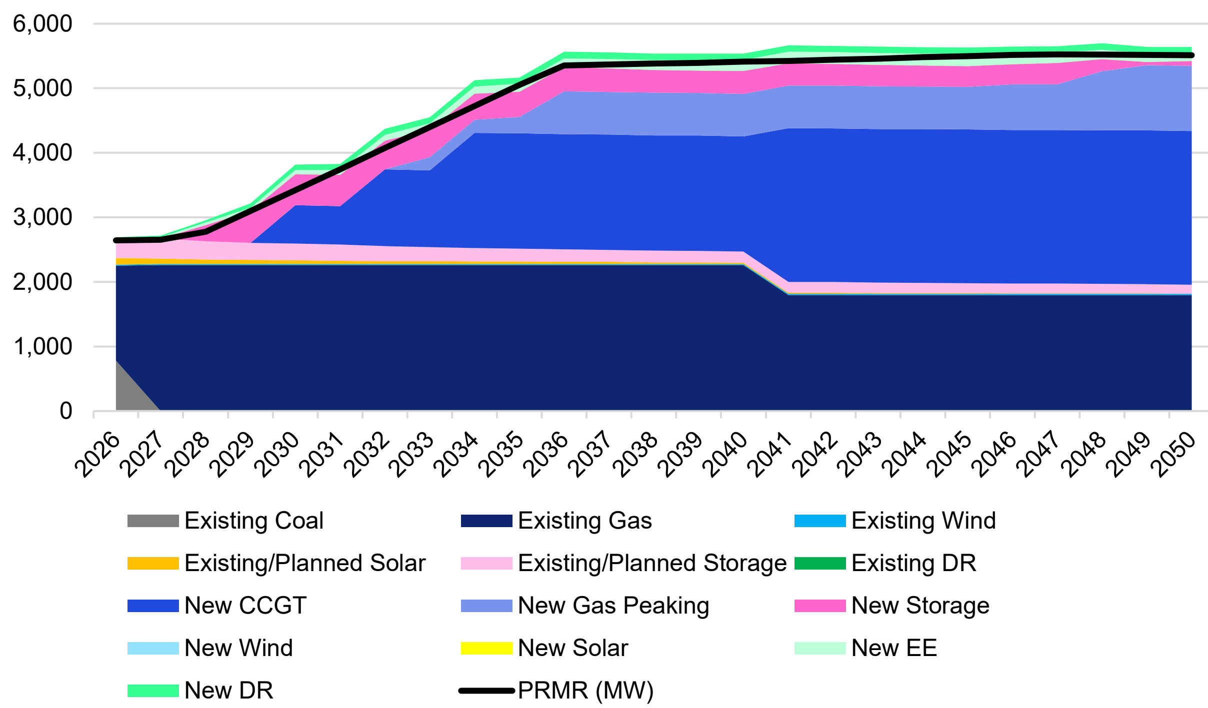


Figure 9-17: Reference Case – High Data Center Load – Winter Firm Capacity (MW)



In Figure 9-14 through Figure 9-17, the firm winter capacity position is shown for the no, low, mid, and high data center cases. AES Indiana has similar firm capacity shortages in winter versus summer; however, solar accreditation is markedly lower in winter and storage winter accreditation decreases over time, often leading to winter shortages and driving the need for some resource selections.

Across all portfolios and scenarios, the firm's capacity from existing gas will decline in the early 2040s as Harding Street units retire. By 2045, across all load profiles in the Reference Case, a new CCGT is brought online, in part to help fill the retirement gap.

Across the load profiles, in earlier years, the portfolios show how demand response and energy storage contribute towards meeting winter requirements. The planned Pete Energy Center and Crossvine projects are needed to support short-term requirements, as is the 2026 conversion of Pete 3 and Pete 4 to natural gas.

The energy positions under the Reference Case are shown in Figure **9-18** through Figure **9-21**.

Figure 9-18: Reference Case - No Data Center Load – Energy Position

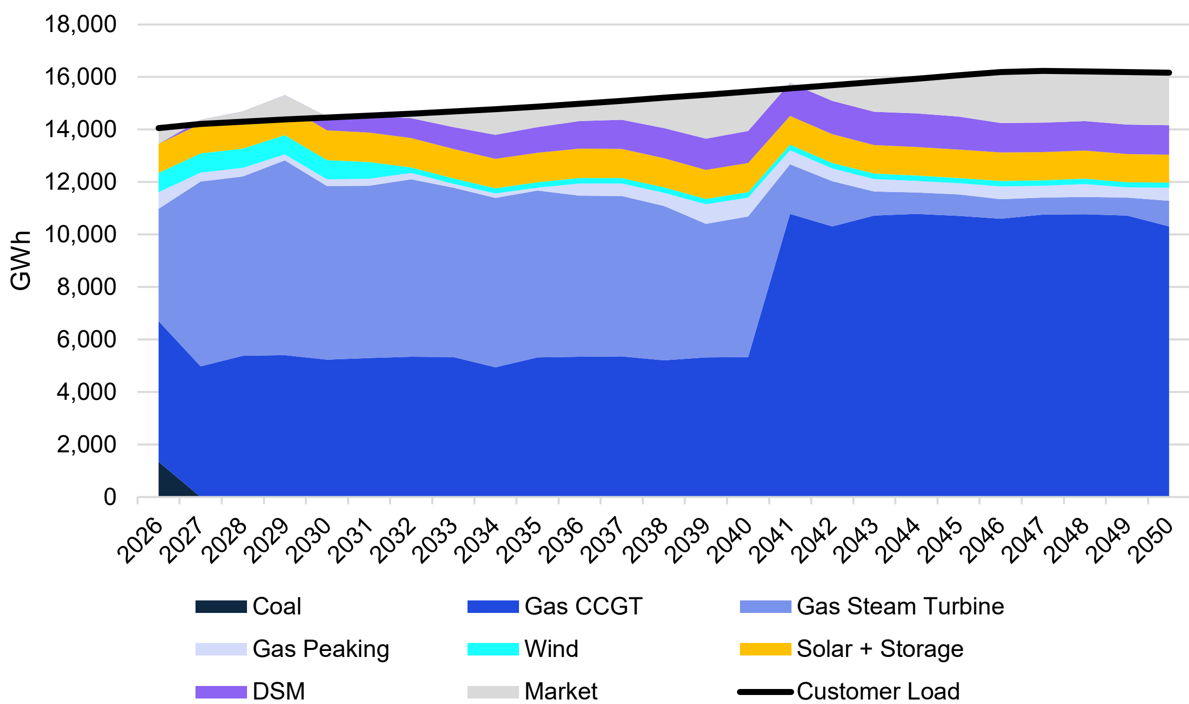


Figure 9-19: Reference Case - Low Data Center Load – Energy Position

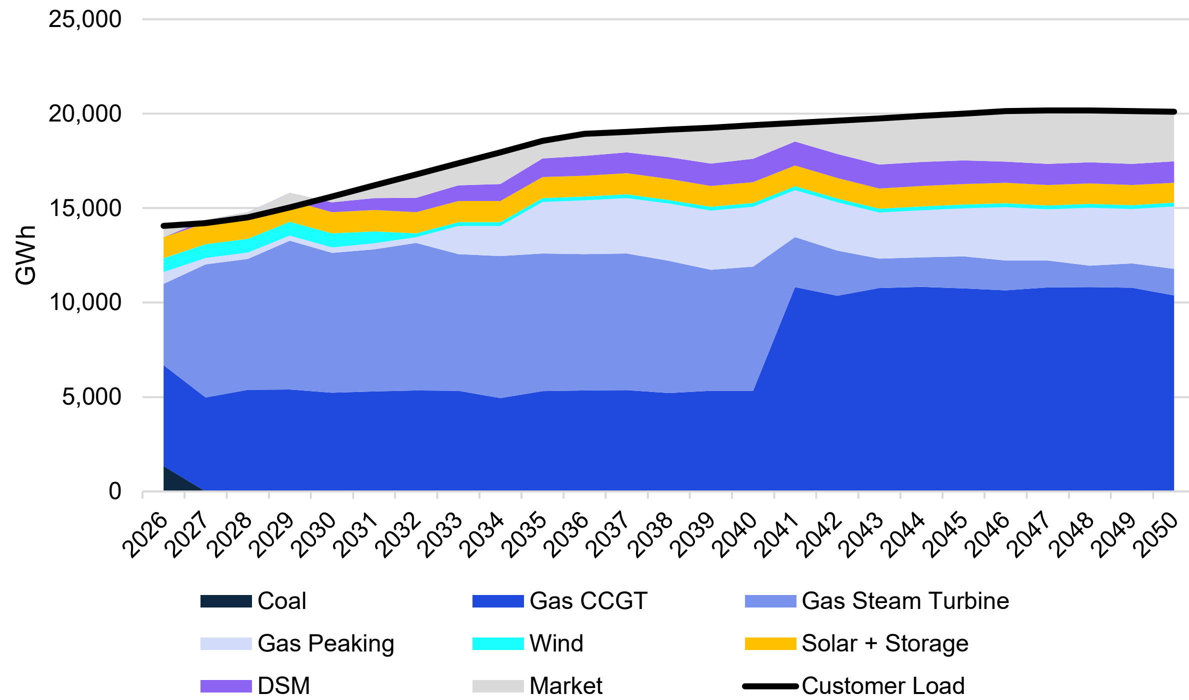


Figure 9-20: Reference Case - Mid Data Center Load – Energy Position

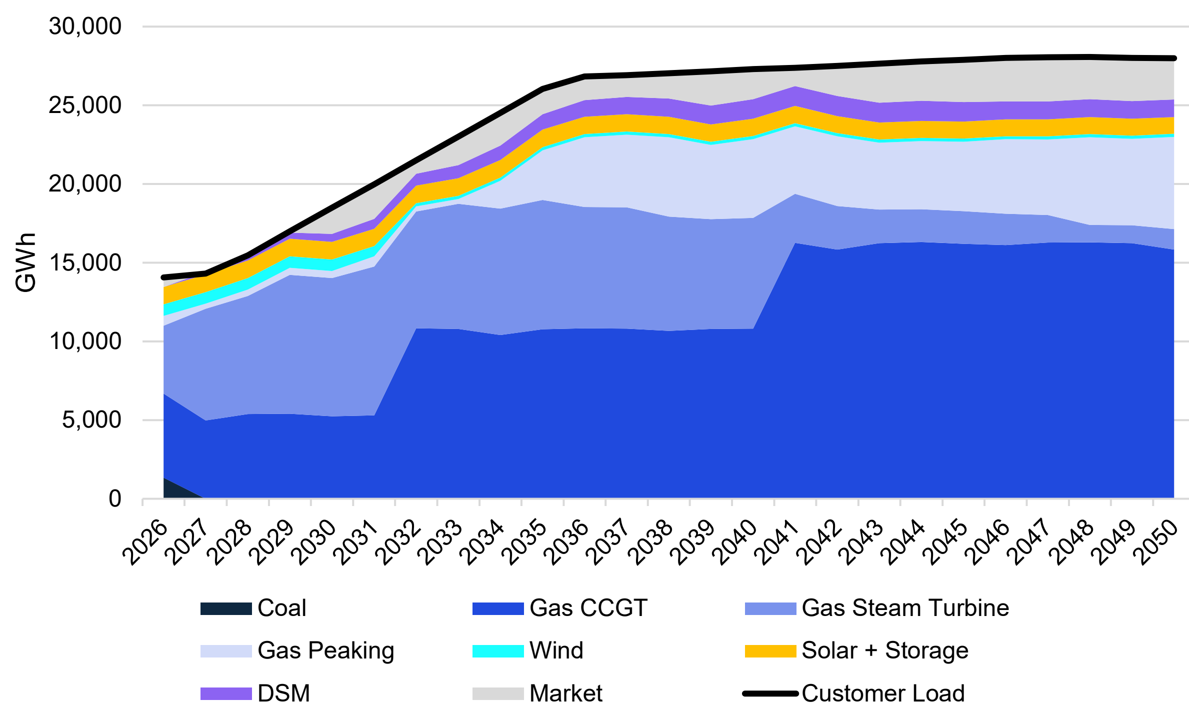
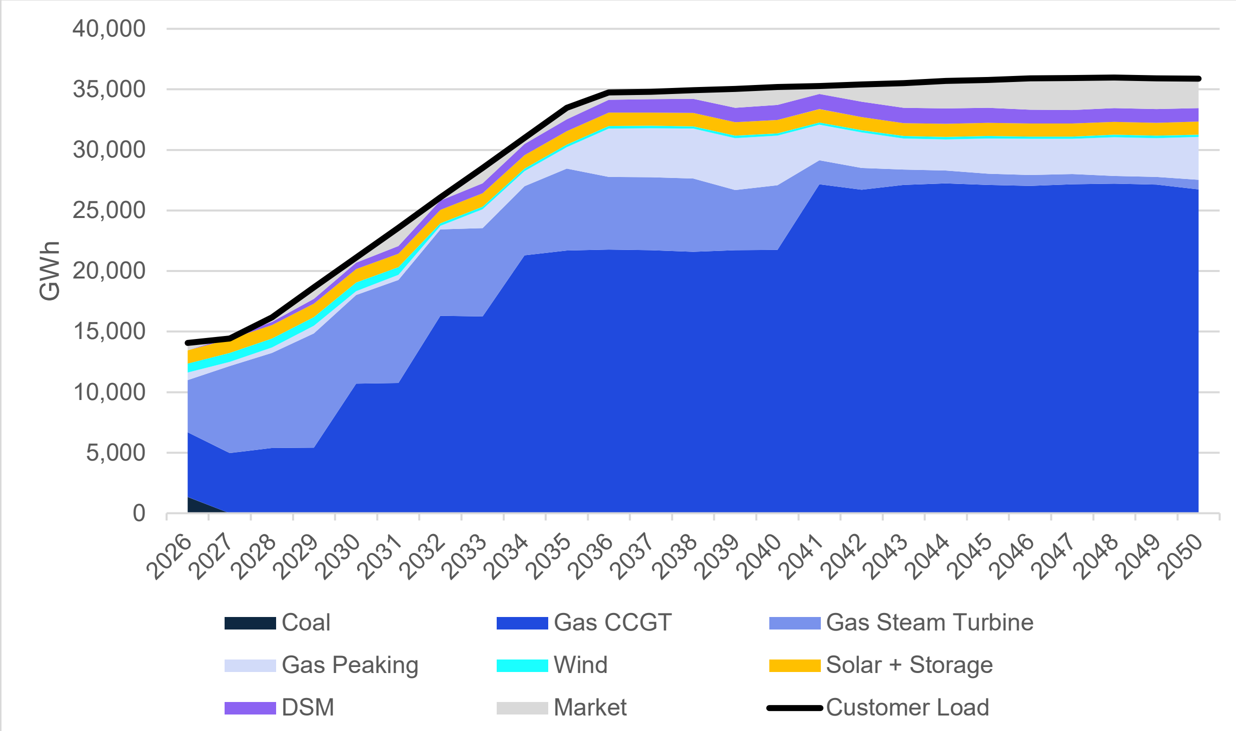


Figure 9-21: Reference Case – High Data Center Load – Energy Position



By 2030, customer load is 4% energy efficiency in the No Data Center: Reference Case and 2% in the High Data Center: Reference Case. Energy from natural gas is 36% combined cycle, 46% steam, and 2% gas peaking in the No Data Center: Reference Case; compared to 51% combined cycle, 35% steam, and 2% gas peaking in the High Data Center: Reference Case. Wind, solar, and storage are 13% in the No Data Center: Reference Case and 9% in the High Data Center. Values are rounded, so may not equal 100% precisely.

Demand-side resources and energy efficiency are available in 2027 to help meet energy and capacity needs. The individual programs procured through 2032 are shown in Figure 9-22.

Across all portfolios, the IQ_Hear and the IQW packages are forced online. Across all load profiles in the Reference Case, the following demand response programs are generally selected: DR BDR, DR Load Curtailment, DR Thermostat, and DR TOU. In terms of energy efficiency, commercial vintages and residential behavior initiatives are selected.

Figure 9-22: Reference Case Demand-Side Resource Selections

	No Data Center	Low Data Center	Mid Data Center	High Data Center
ENERGY EFFICIENCY				
C&I V1	X	X	X	X
C&I V2	X	X	X	X
C&I V3	X	X	X	X
Res BEH Tier1 V1	X	X	X	X
Res BEH Tier1 V2	X	X	X	X
Res BEH Tier1 V3	X	X	X	X
Res Tier2 V1				
Res Tier2 V2				
Res Tier2 V3				
IQW V1	X	X	X	X
IQW V2	X	X	X	X
IQW V3	X	X	X	X
IQ HEAR V1	X	X	X	X
IQ HEAR V2	X	X	X	X
IQ HEAR V3	X	X	X	X
DEMAND RESPONSE				
DR Thermostat	X	X	X	X
DR Battery	X			
DR Load Curtailment	X	X	X	X
DR Capacity Bidding				
DR BDR	X	X	X	X
DR PTR	X	X		X
DR TOU	X	X	X	X

Gas Infrastructure Challenges Scenario

The Gas Infrastructure Challenges scenario stresses natural gas prices and increases firm gas transportation costs for new thermal assets. The results of this scenario are somewhat counterintuitive – the higher natural gas and power prices lead to more combined cycle plants sooner as the data center load increases, the reason for which is further described below. See Figure 9-23 through Figure 9-27 for a view of installed capacity.

Figure 9-23: Gas Infrastructure Challenges – Installed Capacity (MW) by Resource Type and Load Case

		2030	2035	2040	2045
Demand Response	No Data Center Load	186	223	225	224
	Low DC Load	184	218	219	217
	Mid DC Load	186	223	225	224
	High DC Load	186	223	225	224
Energy Efficiency	No Data Center Load	98	191	267	303
	Low DC Load	98	191	267	303
	Mid DC Load	98	191	267	303
	High DC Load	98	191	267	303
Battery Storage	No Data Center Load	20	100	100	100
	Low DC Load	160	160	160	160
	Mid DC Load	320	380	380	380
	High DC Load	560	620	620	620
Gas CCGT	No Data Center Load				700
	Low DC Load		700	700	1,400
	Mid DC Load	700	1,400	1,400	2,100
	High DC Load	700	2,800	2,800	3,500
Gas CT	No Data Center Load				
	Low DC Load				
	Mid DC Load			240	240
	High DC Load				
Gas Reciprocating Engines	No Data Center Load			108	108
	Low DC Load				
	Mid DC Load		108	162	162
	High DC Load			108	108
Solar	No Data Center Load				
	Low DC Load				
	Mid DC Load	50	50	50	50
	High DC Load	25	25	25	25
Wind	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				

Figure 9-24: Gas Infrastructure Challenges – No Data Center Load – Cumulative Installed Capacity (MW)

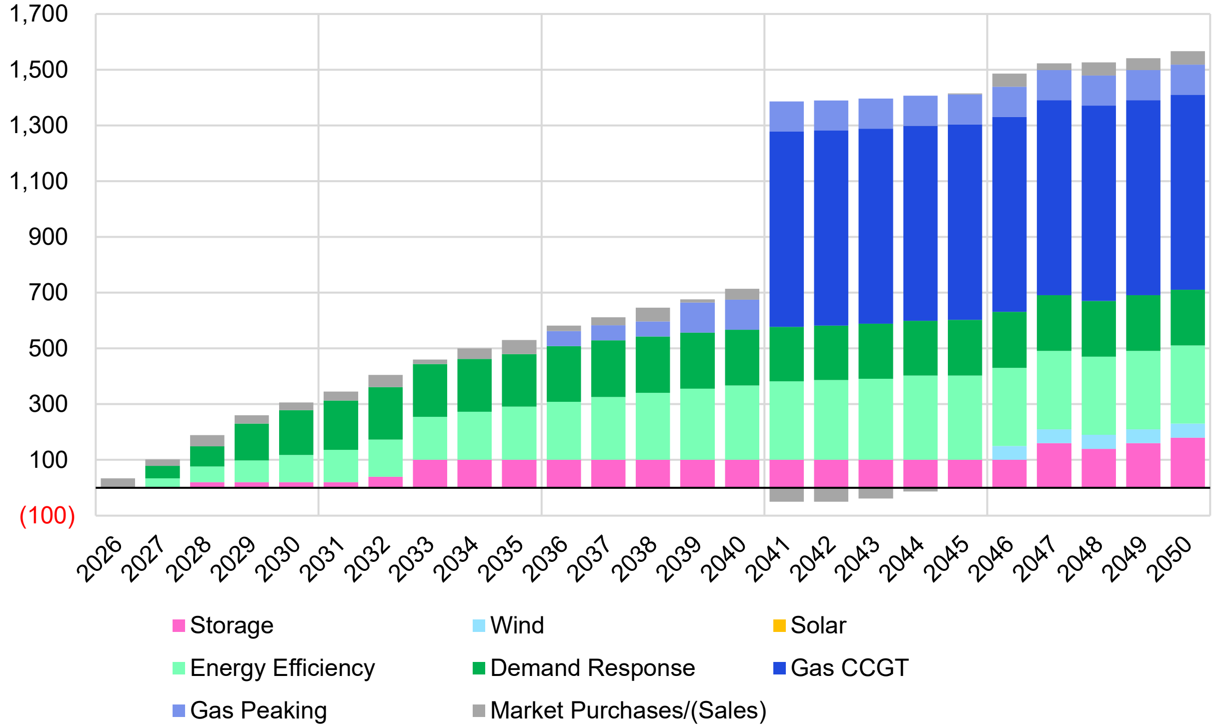


Figure 9-25: Gas Infrastructure Challenges – Low Data Center Load – Cumulative Installed Capacity (MW)

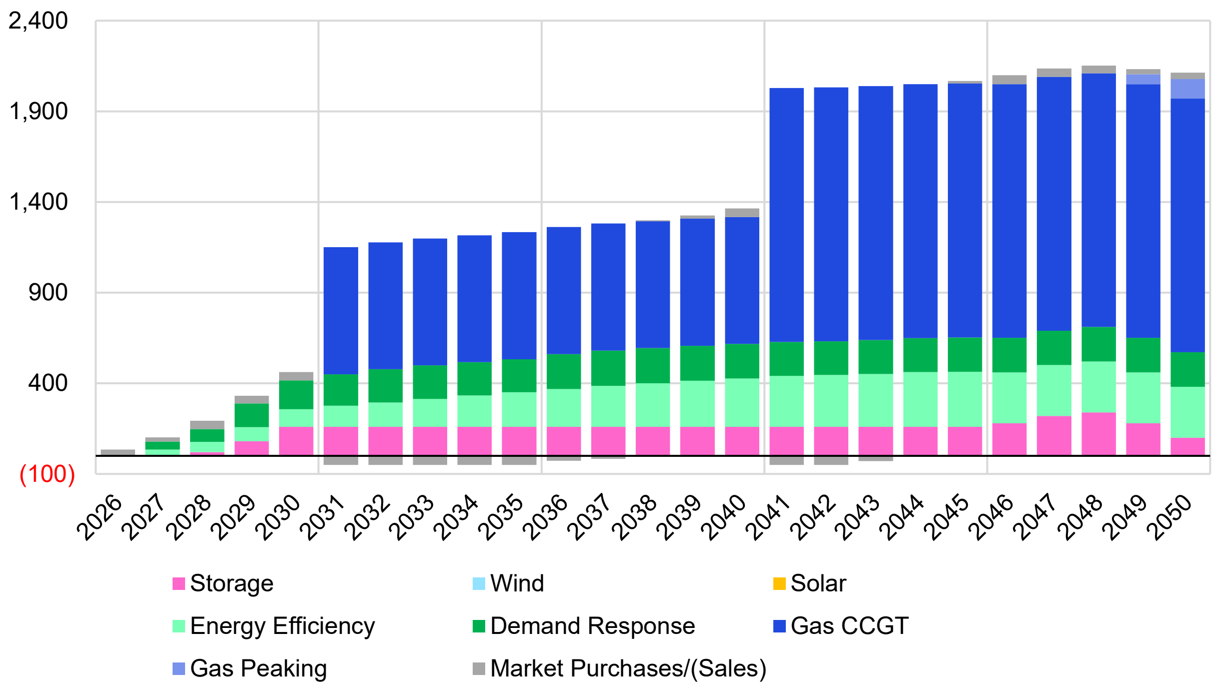


Figure 9-26: Gas Infrastructure Challenges – Mid Data Center Load – Cumulative Installed Capacity (MW)

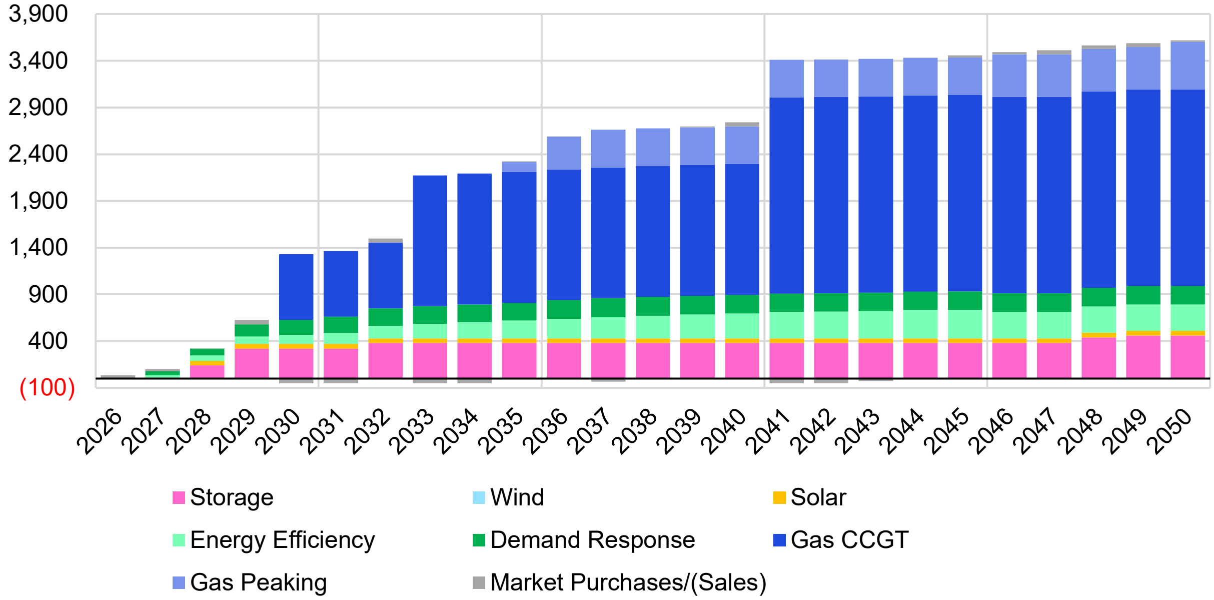
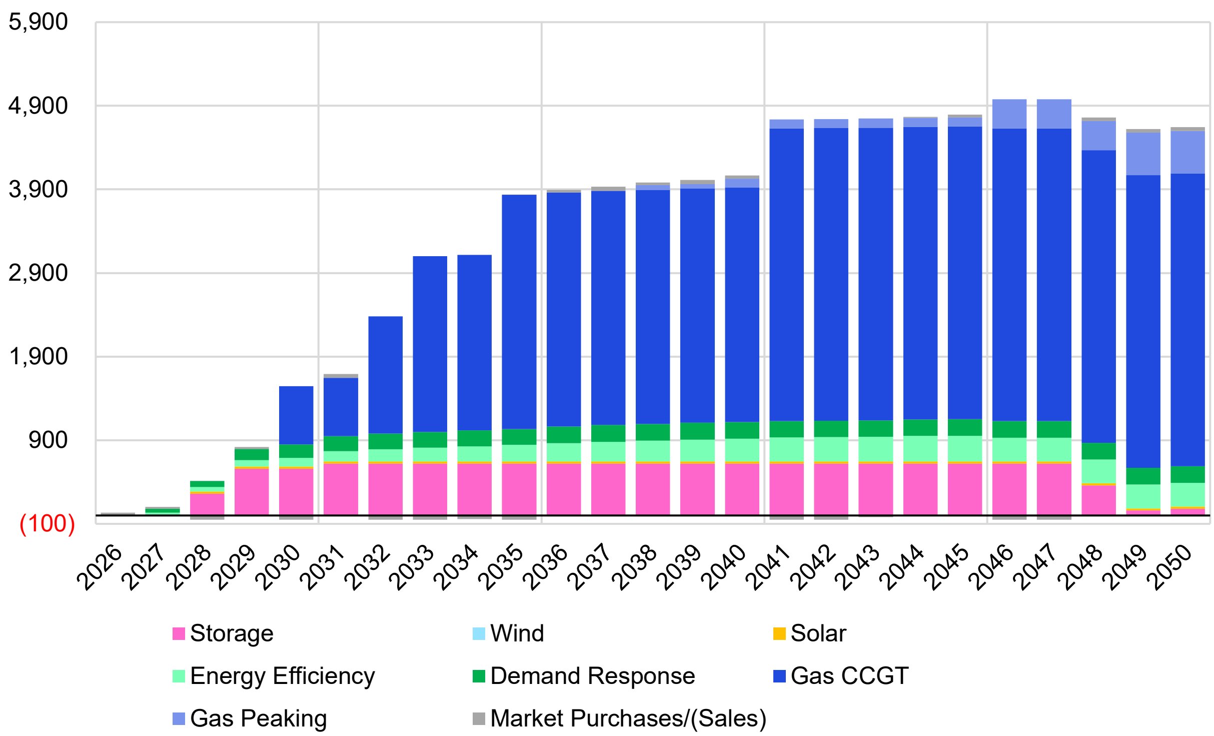


Figure 9-27: Gas Infrastructure Challenges – High Data Center Load – Cumulative Installed Capacity (MW)



As seen through Figure 9-28 through Figure 9-31, which display the short-term installed capacity additions, without data center load, demand response, energy efficiency, and battery storage, meets short-term resource needs to cover AES Indiana's native load. With low data center load, a combined cycle is brought online in 2031; in the mid and high data center cases, it is brought online in 2030, which is the earliest available model year. In comparison, in the Low Data Center: Reference Case, no combined cycle is brought online. In the Reference Case, the mid and high cases bring a combined cycle plant online in 2032 and 2030, respectively.

Figure 9-28: Gas Infrastructure Challenges – No Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		20	20	20	20	40	100	100	100
Gas CCGT									
Gas CT									
Gas Reciprocating Engines									
Solar									
Wind									

Figure 9-29: Gas Infrastructure Challenges – Low Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	152	184	204	214	216	217	218
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		20	80	160	160	160	160	160	160
Gas CCGT					700	700	700	700	700
Gas CT									
Gas Reciprocating Engines									
Solar									
Wind									

Figure 9-30: Gas Infrastructure Challenges – Mid Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		140	320	320	320	380	380	380	380
Gas CCGT				700	700	700	1,400	1,400	1,400
Gas CT									
Gas Reciprocating Engines									108
Solar		50	50	50	50	50	50	50	50
Wind									

Figure 9-31: Gas Infrastructure Challenges – High Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		260	560	560	620	620	620	620	620
Gas CCGT				700	700	1,400	2,100	2,100	2,800
Gas CT									
Gas Reciprocating Engines									
Solar		25	25	25	25	25	25	25	25
Wind									

The resulting firm capacity positions for the Gas Infrastructure Challenges portfolios are shown in Figure 9-32 through Figure 9-35.

Figure 9-32: Gas Infrastructure Challenges – No Data Center Load – Winter Firm Capacity (MW)

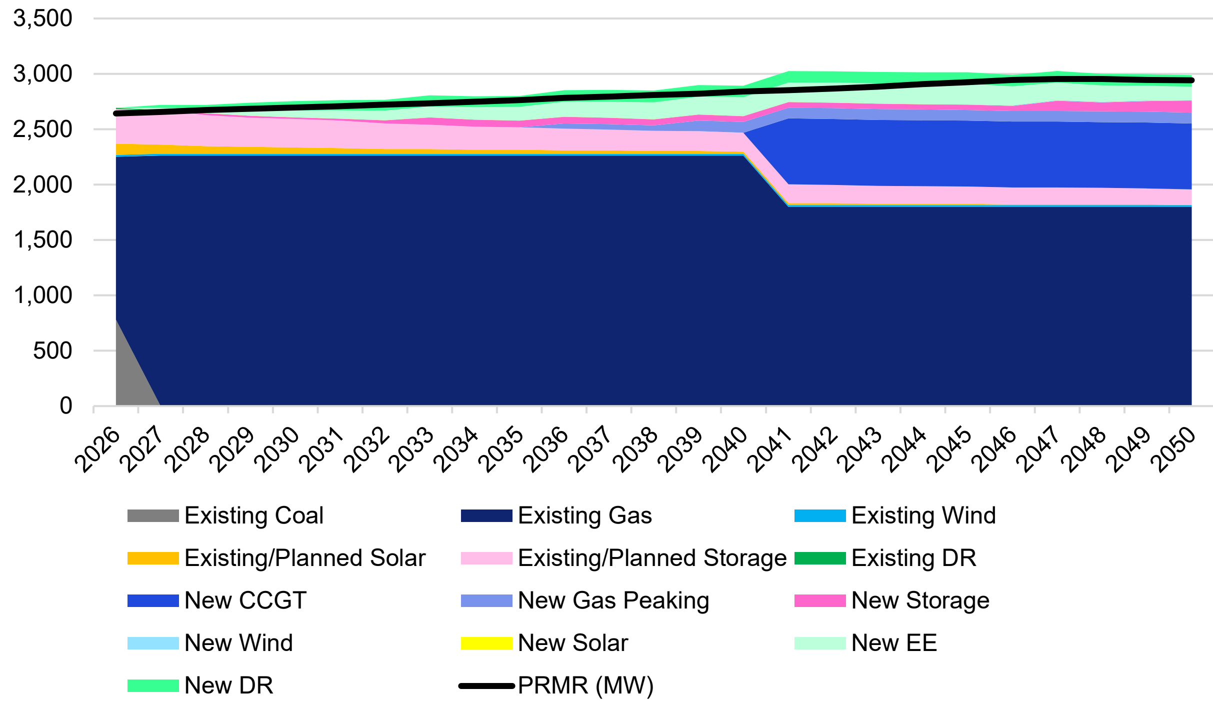


Figure 9-33: Gas Infrastructure Challenges – Low Data Center Load – Winter Firm Capacity (MW)

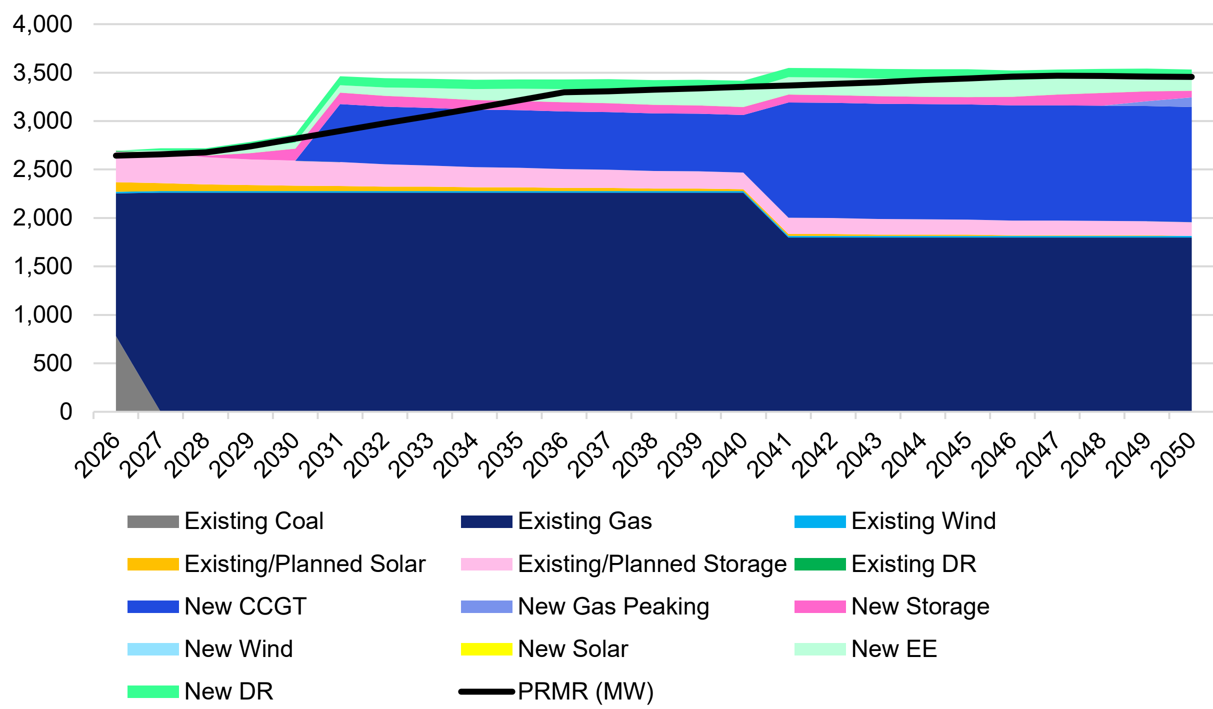


Figure 9-34: Gas Infrastructure Challenges – <u>Mid</u> Data Center Load - Winter Firm Capacity (MW)

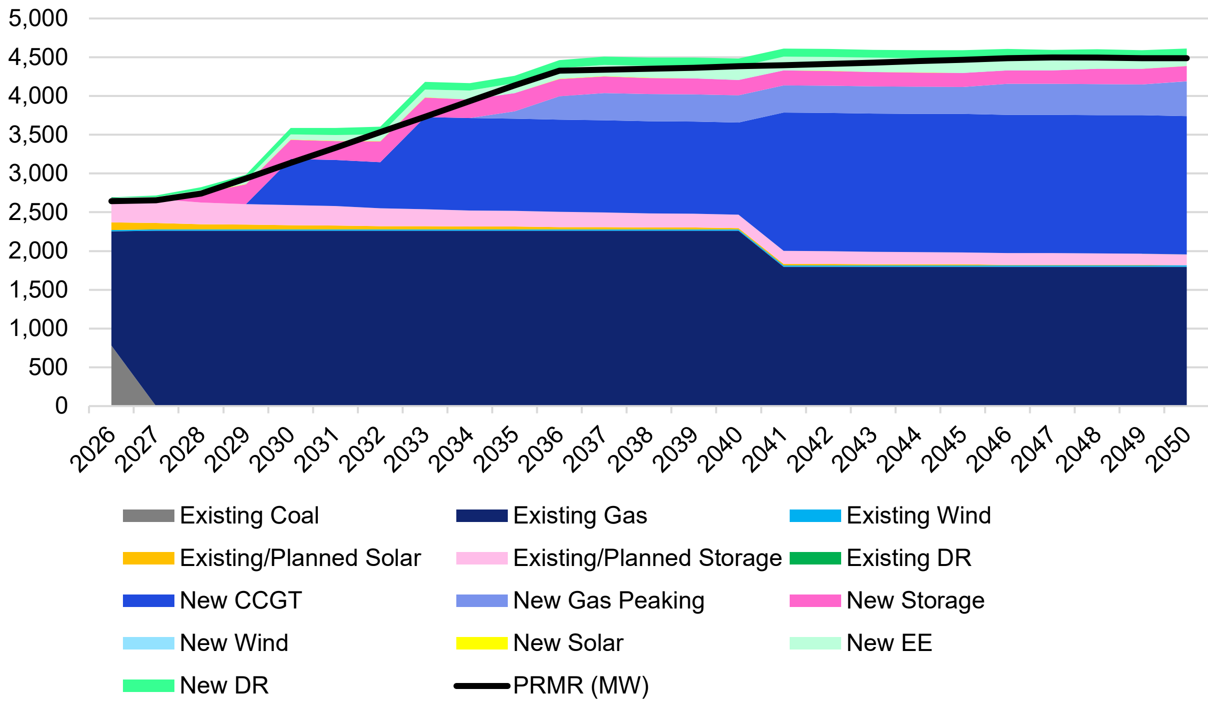
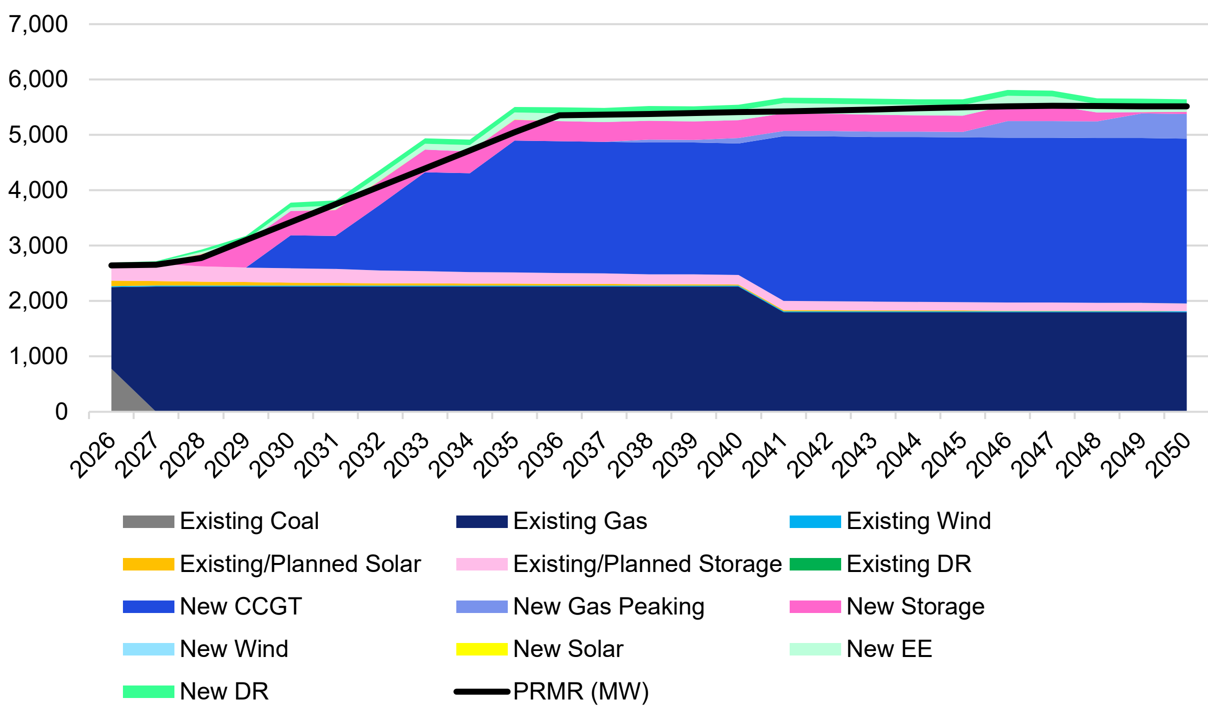


Figure 9-35: Gas Infrastructure Challenges – High Data Center Load - Winter Firm Capacity (MW)



The question is: why is a combined cycle installed sooner if gas prices are higher? This is mainly due to the combination of energy market constraints and changes in the unit economics of the higher-heat-rate units that make up AES Indiana's existing gas fleet. Figure 9-36 shows annual capacity factors for the Petersburg Unit 3 gas unit and the Eagle Valley CCGT from the hourly dispatch runs for the Mid Data Center case. In the high gas price scenario, market implied heat rates are lower and push out more expensive gas units (i.e., higher heat rate units), but they are not low enough to reduce the unit economics of combined cycle plants. Overall, this scenario shows that a sustained natural gas price environment requires a more efficient natural gas fleet.

Figure 9-36: Annual Capacity Factors (%): Pete 3 ST (10.8 HR[60]) and Eagle Valley CCGT (6.7 HR)

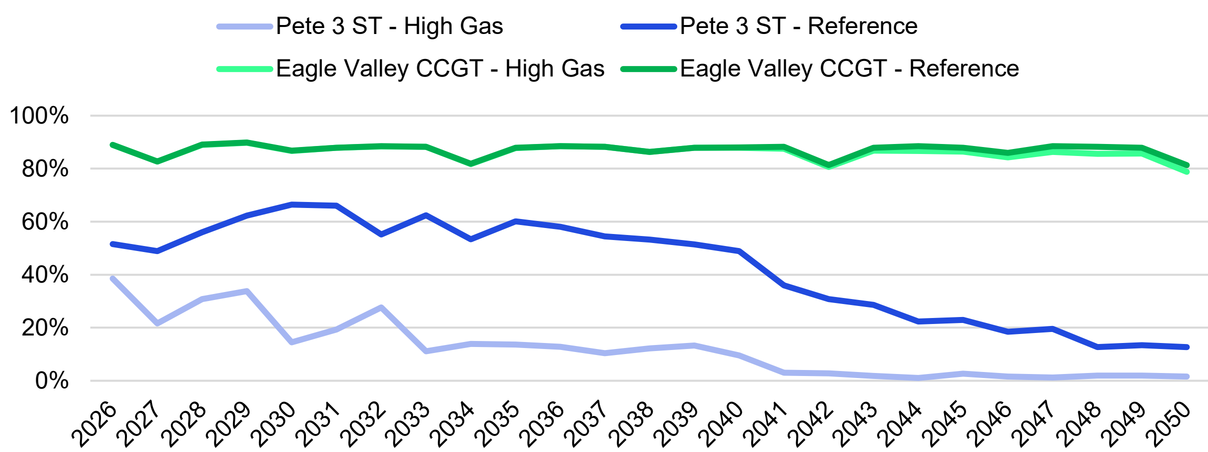
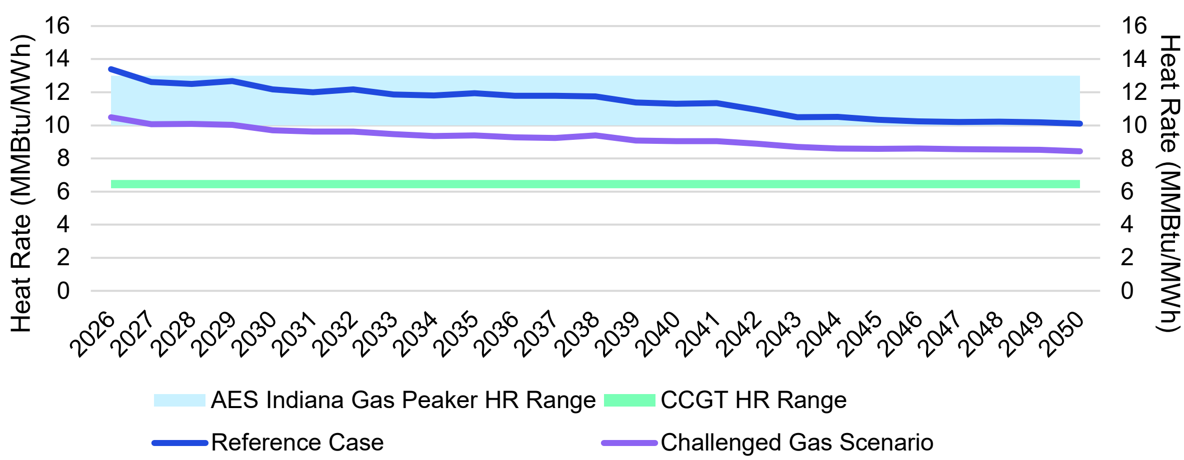


Figure 9-37: 7x24 Annual Market Implied Heat Rates vs HR Range of Gas Units



Because of the expiration of tax credits, new wind and solar is not added. However, in a sustained high natural gas price environment, additional renewable additions would push market implied

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[60] HR = Heat Rate (MMBtu/MWh)

heat rates even lower and could erode CCGT economics. Scenario 3, the High Regulatory: Environmental Scenario, captures some of this effect, though it is exacerbated by the 40% annual capacity limit on CCGTs in that scenario.

Energy positions are shown in Figure **9-38** through Figure **9-41**. The dark blue emphasizes the combined cycle energy.

Figure 9-38: Gas Infrastructure Challenges - No Data Center Load - Energy Position

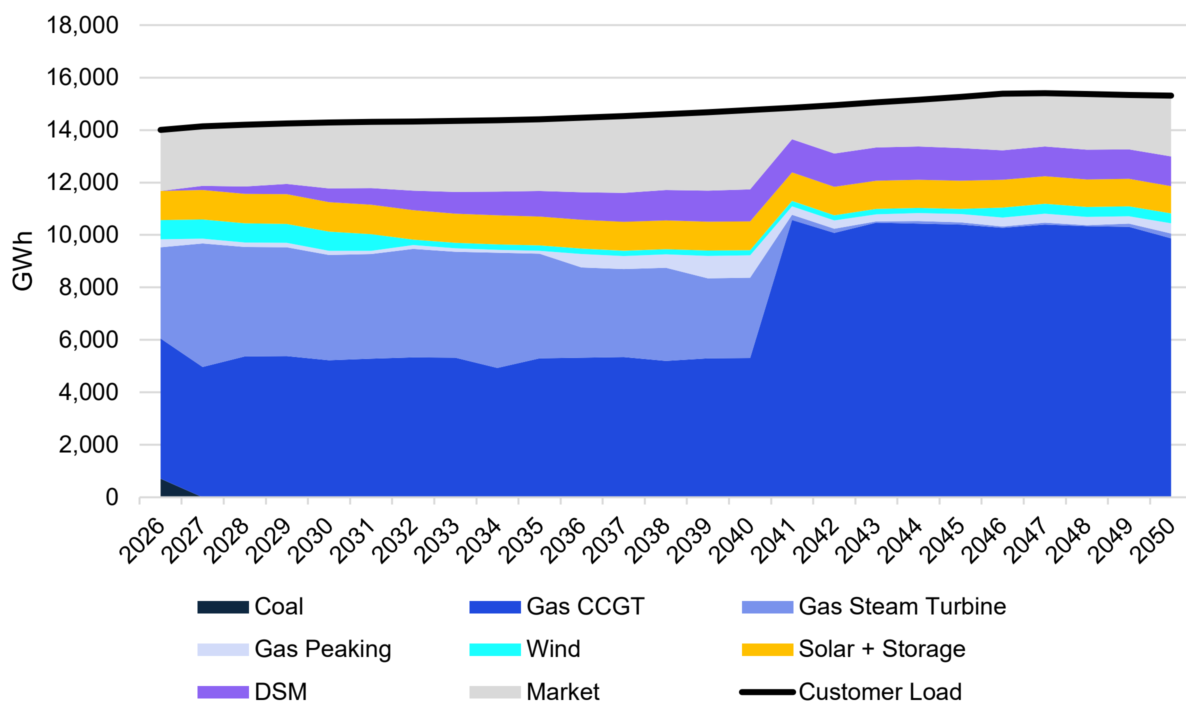


Figure 9-39: Gas Infrastructure Challenges – Low Data Center Load - Energy Position

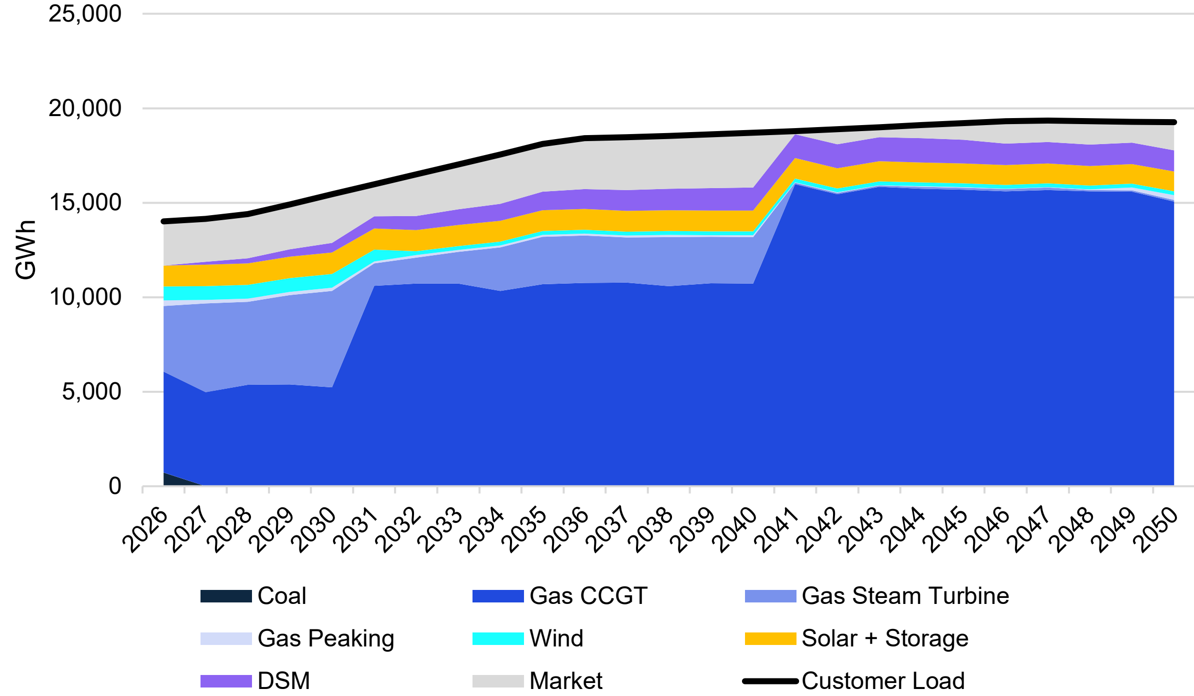


Figure 9-40: Gas Infrastructure Challenges - Mid Data Center Load - Energy Position

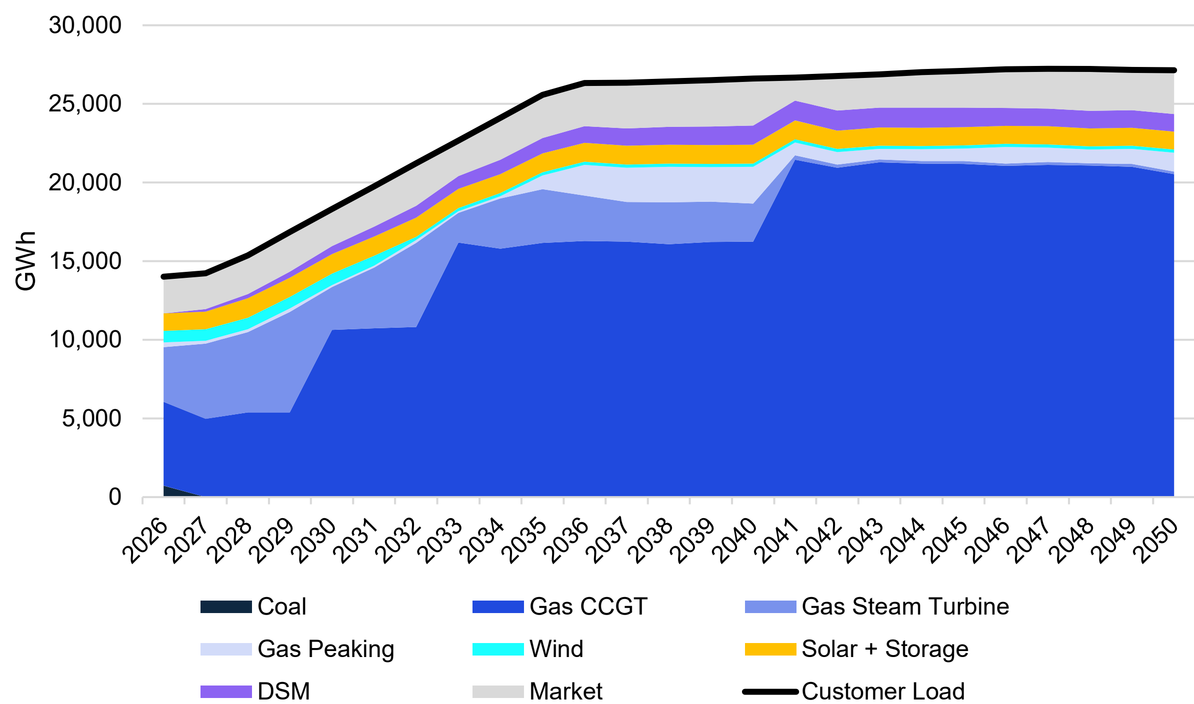
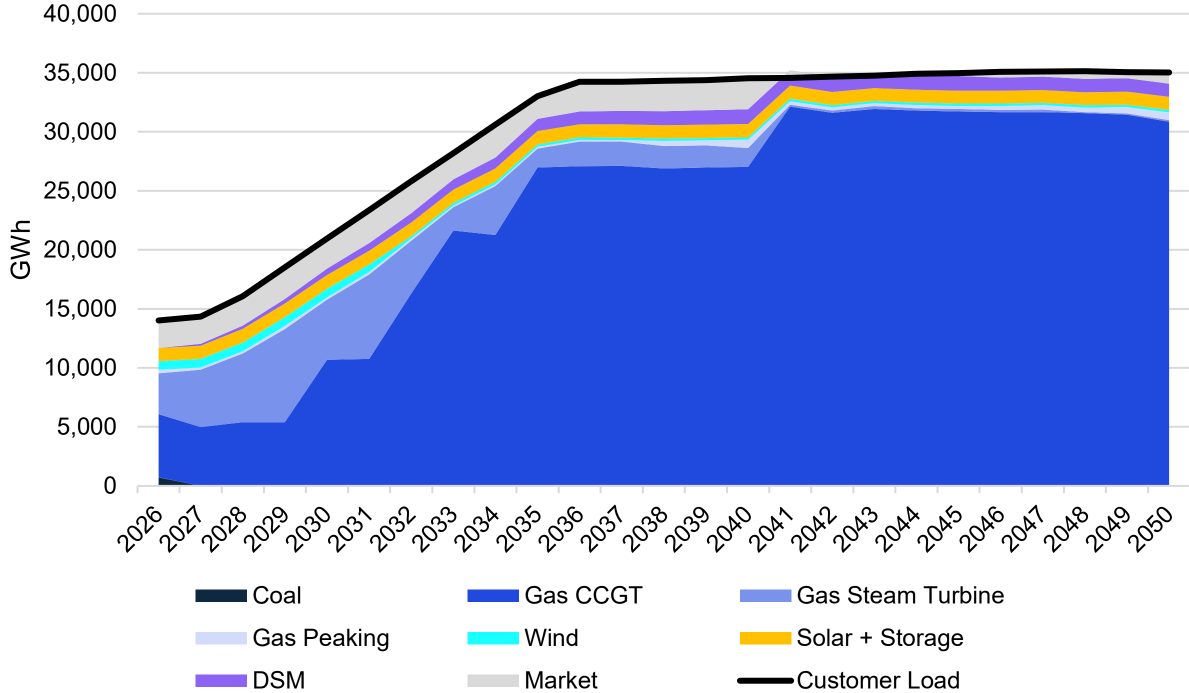


Figure 9-41: Gas Infrastructure Challenges – High Data Center Load - Energy Position



By 2030, customer load is 4% energy efficiency in the No Data Center: Gas Infrastructure Challenges and 3% in the High Data Center: Gas Infrastructure Challenges. Gas combined cycle energy is 37% combined cycle, 28% steam, and 1% gas peaking in the No Data Center: Gas Infrastructure Challenges scenario; compared to 51% combined cycle, 24% steam, and 1% gas peaking in the High Data Center: Gas Infrastructure Challenges scenario. Wind, solar, and storage are 13% in the No Data Center: Gas Infrastructure Challenges and 9% in the High Data Center scenario.

Like Reference Case portfolios, the Gas Infrastructure Challenges portfolios include demand response and energy efficiency to serve capacity and energy needs. Like the Reference Case, the same five demand response selections (DR BDR, DR Load Curtailment, DR Thermostat, and DR TOU) are brought online, along with some DR battery selections. In terms of energy efficiency, the commercial vintages and the residential behavior initiatives are selected.

Figure 9-42: Gas Infrastructure Challenges Demand-Side Resource Selections

	No Data Center	Low Data Center	Mid Data Center	High Data Center
ENERGY EFFICIENCY				
C&I V1	X	X	X	X
C&I V2	X	X	X	X
C&I V3	X	X	X	X
Res BEH Tier1 V1	X	X	X	X
Res BEH Tier1 V2	X	X	X	X
Res BEH Tier1 V3	X	X	X	X
Res Tier2 V1				
Res Tier2 V2				X
Res Tier2 V3				
IQW V1	X	X	X	X
IQW V2	X	X	X	X
IQW V3	X	X	X	X
IQ HEAR V1	X	X	X	X
IQ HEAR V2	X	X	X	X
IQ HEAR V3	X	X	X	X
DEMAND RESPONSE				
DR Thermostat	X	X	X	X
DR Battery	X		X	X
DR Load Curtailment	X	X	X	X
DR Capacity Bidding				
DR BDR	X	X	X	X
DR PTR	X	X	X	X
DR TOU	X	X	X	X

High Regulatory: Environmental Scenario

The High Regulatory: Environmental Scenario reflects resource selection and performance in a world where gas resources are more expensive and operations are constrained, and where renewables and storage resources are more cost-effective due to tax credit policies. Exposing other portfolios to this High Regulatory: Environmental Scenario also helps show how those resource mixes would perform if additional environmental regulations or incentives were promulgated.

The installed capacity of the portfolios is shown in Figure 9-43.

Figure 9-43: High Regulatory: Environmental - Installed Capacity (MW) by Resource Type and Load Case

		2030	2035	2040	2045
Demand Response	No Data Center Load	130	156	158	157
	Low DC Load	130	156	158	157
	Mid DC Load	130	156	158	157
	High DC Load	130	156	158	157
Energy Efficiency	No Data Center Load	98	191	267	303
	Low DC Load	98	191	267	303
	Mid DC Load	98	191	267	303
	High DC Load	98	191	267	303
Battery Storage	No Data Center Load	100	120	180	1,000
	Low DC Load	300	780	1,020	1,880
	Mid DC Load	640	1,840	2,340	3,240
	High DC Load	940	2,480	2,960	3,140
Gas CCGT	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				
Gas CT	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load		480	480	1,200
Gas Reciprocating Engines	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				
Solar	No Data Center Load	25	25	50	275
	Low DC Load		350	375	675
	Mid DC Load	50	1,050	1,525	2,025
	High DC Load	100	1,225	2,500	2,600
Wind	No Data Center Load	50	900	2,050	2,550
	Low DC Load		1,350	2,650	3,250
	Mid DC Load	350	2,750	4,250	5,150
	High DC Load	400	2,800	5,250	6,400

As is shown in Figure 9-44, the High Regulatory: Environmental portfolios install more wind and solar than the other portfolios and less natural gas. Cumulative installed capacity by type is demonstrated in Figure 9-44 through Figure 9-48.

Across load profiles, combined cycles are not selected. In this scenario, combined cycles are limited to a capacity factor of 40% to account for potential future environmental regulations. Only the high-data-center case adds new gas peakers. The model selects large storage volumes due to available tax credits, high thermal capital costs, and high gas prices.

Figure 9-44: High Regulatory: Environmental - Cumulative Installed Capacity through 2035 (MW)

		DSM	Natural Gas	Storage	Solar	Wind
No Data Center Load	Reference	414	0	100	0	0
	Scenario 2	414	0	100	0	0
	Scenario 3	**414**	**0**	**120**	**25**	**900**
	Scenario 4	278	0	0	0	0
Low Data Center Load (500 MW)	Reference	409	480	420	0	0
	Scenario 2	409	700	160	0	0
	Scenario 3	**414**	**0**	**780**	**350**	**1,350**
	Scenario 4	409	480	120	50	0
Mid Data Center Load (1,500 MW)	Reference	391	1,180	860	0	0
	Scenario 2	414	1,508	380	50	0
	Scenario 3	**414**	**0**	**1,840**	**1,050**	**2,750**
	Scenario 4	414	960	720	100	0
High Data Center Load (2,500 MW)	Reference	409	2,394	640	0	0
	Scenario 2	414	2,800	620	25	0
	Scenario 3	**414**	**480**	**2,480**	**1,225**	**2,800**
	Scenario 4	409	2,140	960	100	0

Figure 9-45: High Regulatory: Environmental – No Data Center Load – Cumulative Installed Capacity (MW)

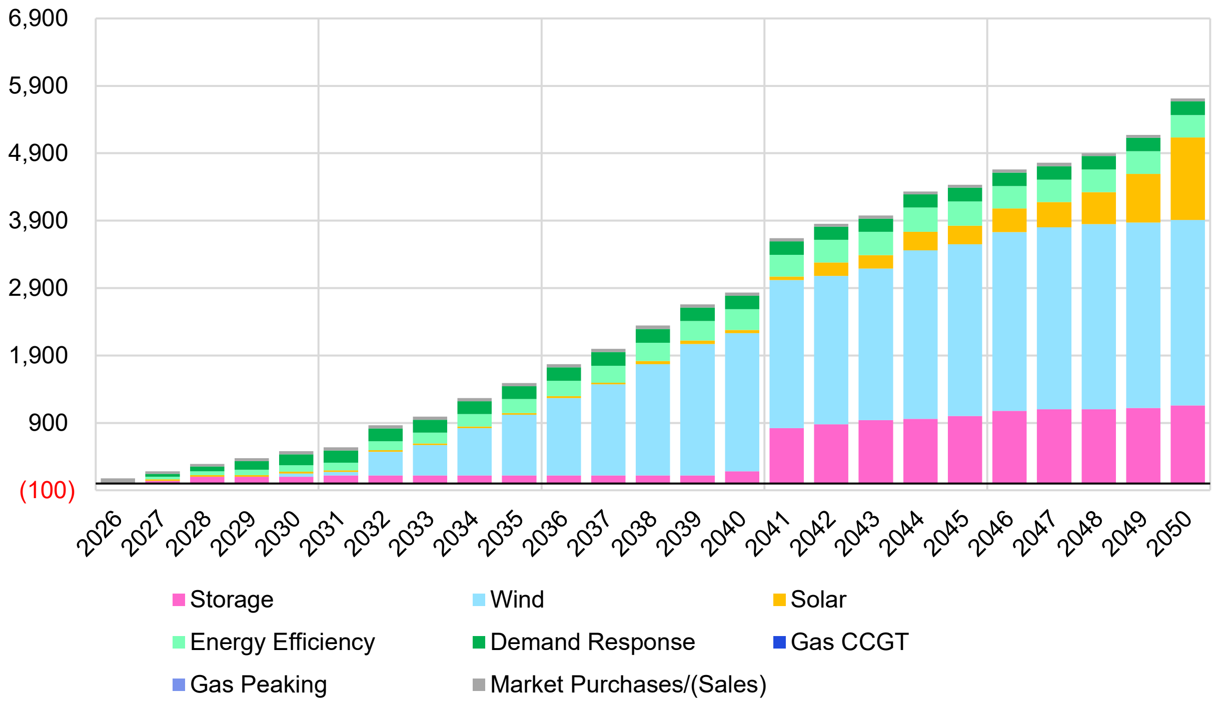


Figure 9-46: High Regulatory: Environmental – Low Data Center Load - Cumulative Installed Capacity (MW)

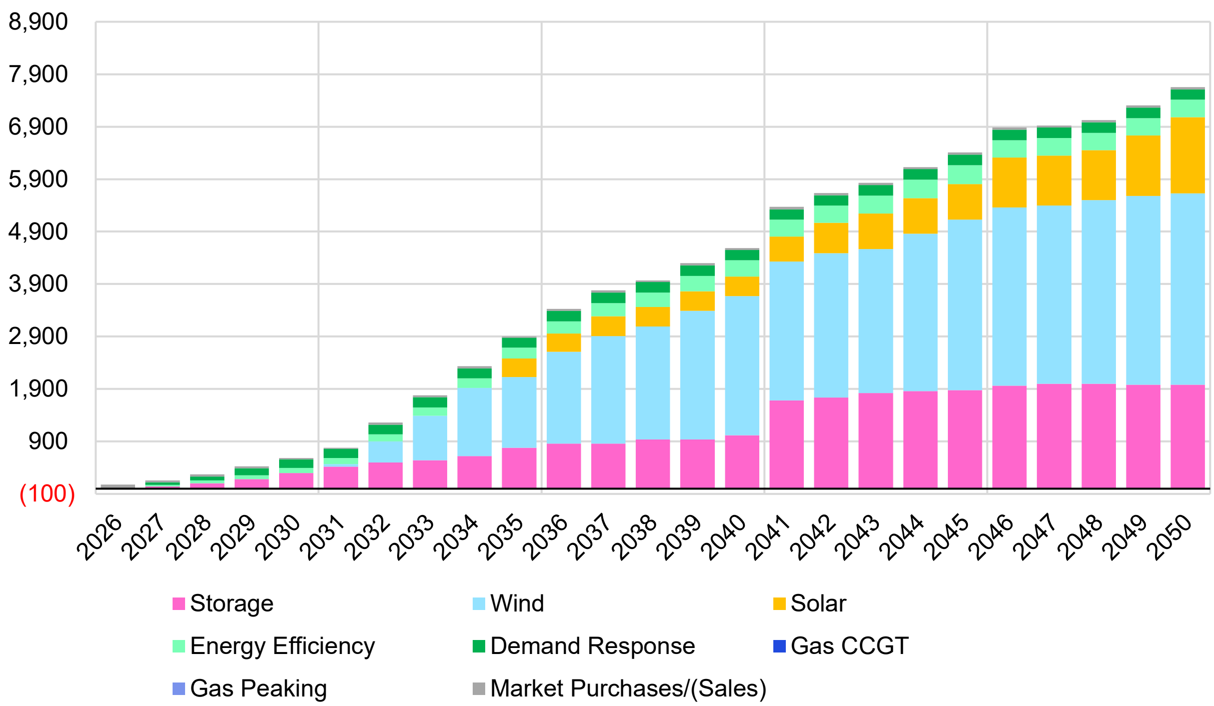


Figure 9-47: High Regulatory: Environmental – <u>Mid</u> Data Center Load – Cumulative Installed Capacity (MW)

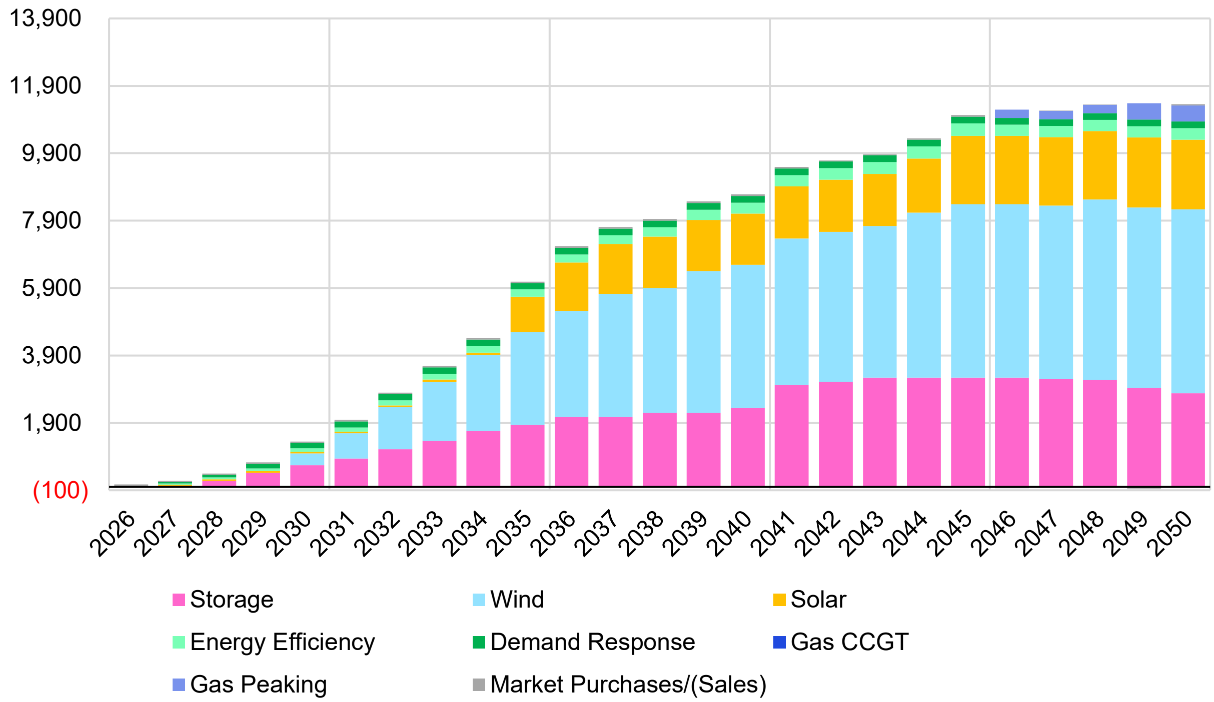
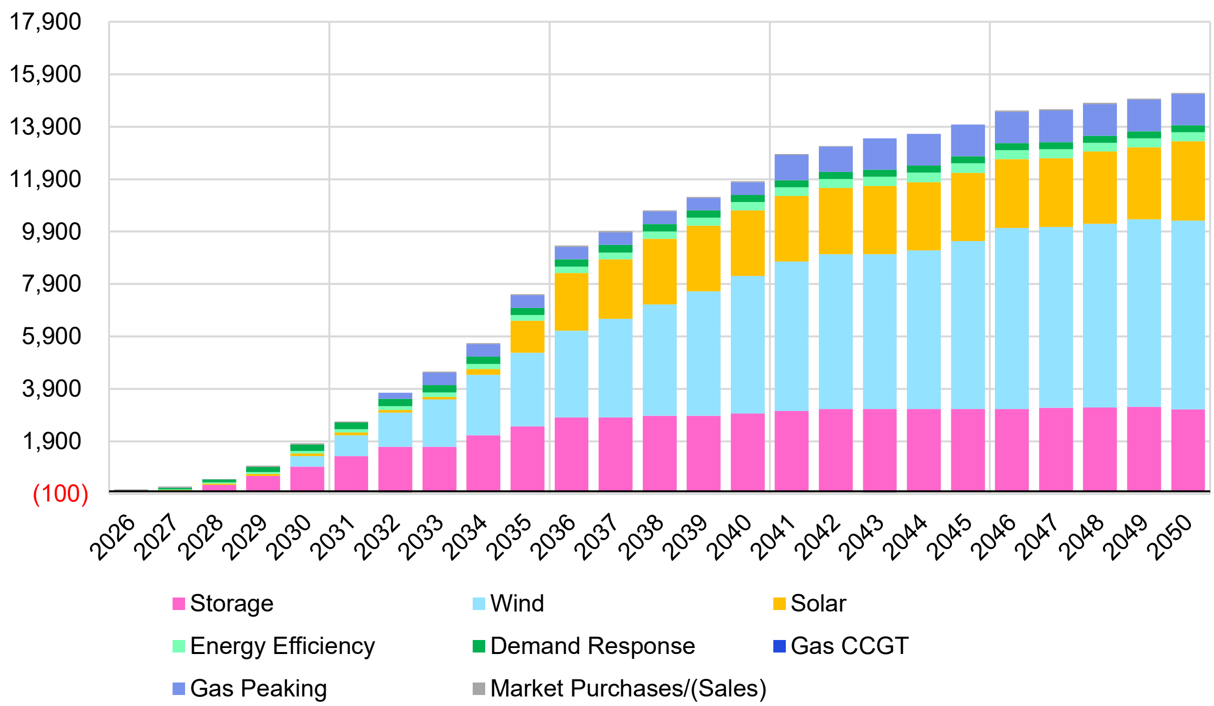


Figure 9-48: High Regulatory: Environmental – <u>High</u> Data Center Load – Cumulative Installed Capacity (MW)



Near-term resource additions are identified in Figure 9-49 through Figure 9-52. As demonstrated in these figures, model selection favors wind and solar energy sources. For example, by 2035 in the mid data center case, 2.7 GW of new wind and 1 GW of new solar are brought online.

Figure 9-49: High Regulatory: Environmental – No Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage	40	100	100	100	120	120	120	120	120
Gas CCGT									
Gas CT									
Gas Reciprocating Engines									
Solar	25	25	25	25	25	25	25	25	25
Wind				50	50	350	450	700	900

Figure 9-50: High Regulatory: Environmental – Low Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage	40	100	180	300	420	500	540	620	780
Gas CCGT									
Gas CT									
Gas Reciprocating Engines									
Solar									350
Wind					50	400	850	1,300	1,350

Figure 9-51: High Regulatory: Environmental – <u>Mid</u> Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage	40	180	420	640	840	1,120	1,360	1,660	1,840
Gas CCGT									
Gas CT									
Gas Reciprocating Engines									
Solar	25	50	50	50	50	50	75	75	1,050
Wind				350	750	1,250	1,750	2,250	2,750

Figure 9-52: High Regulatory: Environmental – <u>High</u> Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage	20	240	580	940	1,340	1,700	1,700	2,140	2,480
Gas CCGT									
Gas CT						240	480	480	480
Gas Reciprocating Engines									
Solar	25	50	75	100	100	100	100	225	1,225
Wind				400	800	1,300	1,800	2,300	2,800

The firm capacity positions shown in Figure 9-53 through Figure 9-56. The light blue represents wind. In 2035, the summer capacity accreditation of wind versus solar is 11% versus 4%, respectively. In winter 2035, the capacity accreditation of wind versus solar is 15% versus 0%, respectively. This is why, on the winter firm capacity graphs, solar capacity is negligible, and wind capacity is lower than what is visible in the installed capacity views. The ability of wind to provide some winter capacity value fits a portfolio need. As data center load increases, firm storage capacity becomes essential. The existing gas fleet, while energy operations are constrained (as discussed in the next section), provides firm capacity.

Figure 9-53: High Regulatory: Environmental – No Data Center Load – Winter Firm Capacity (MW)

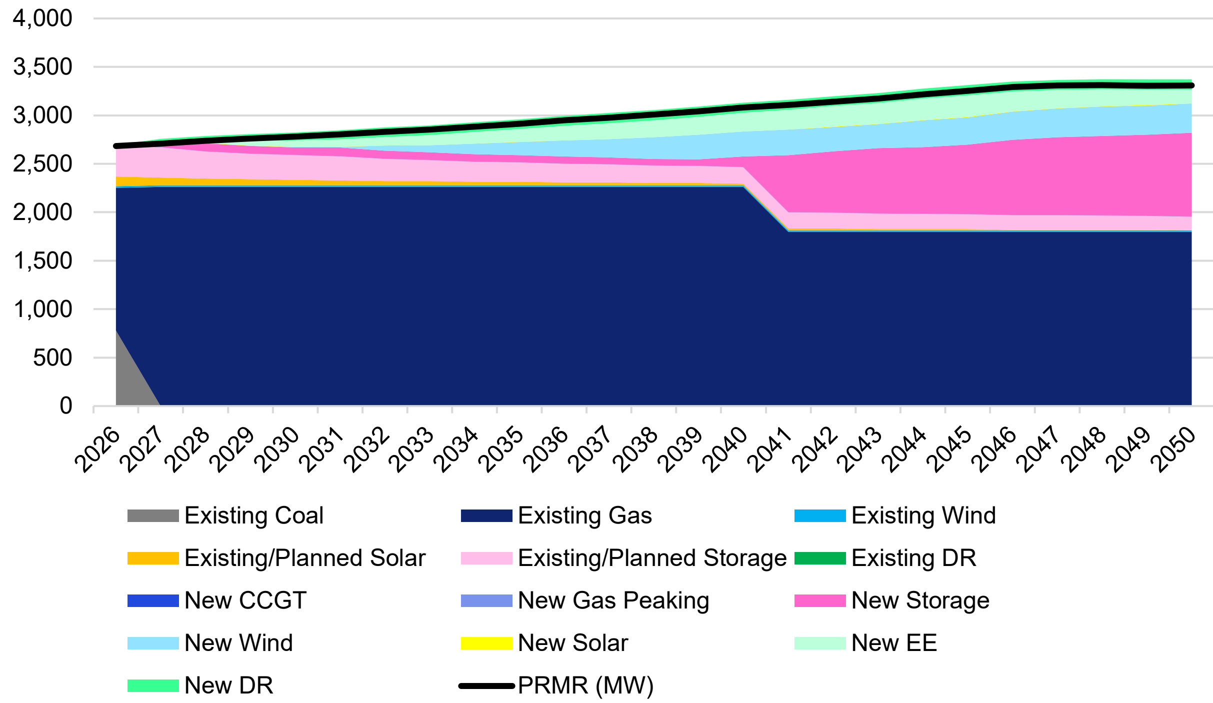


Figure 9-54: High Regulatory: Environmental – Low Data Center Load - Winter Firm Capacity (MW)

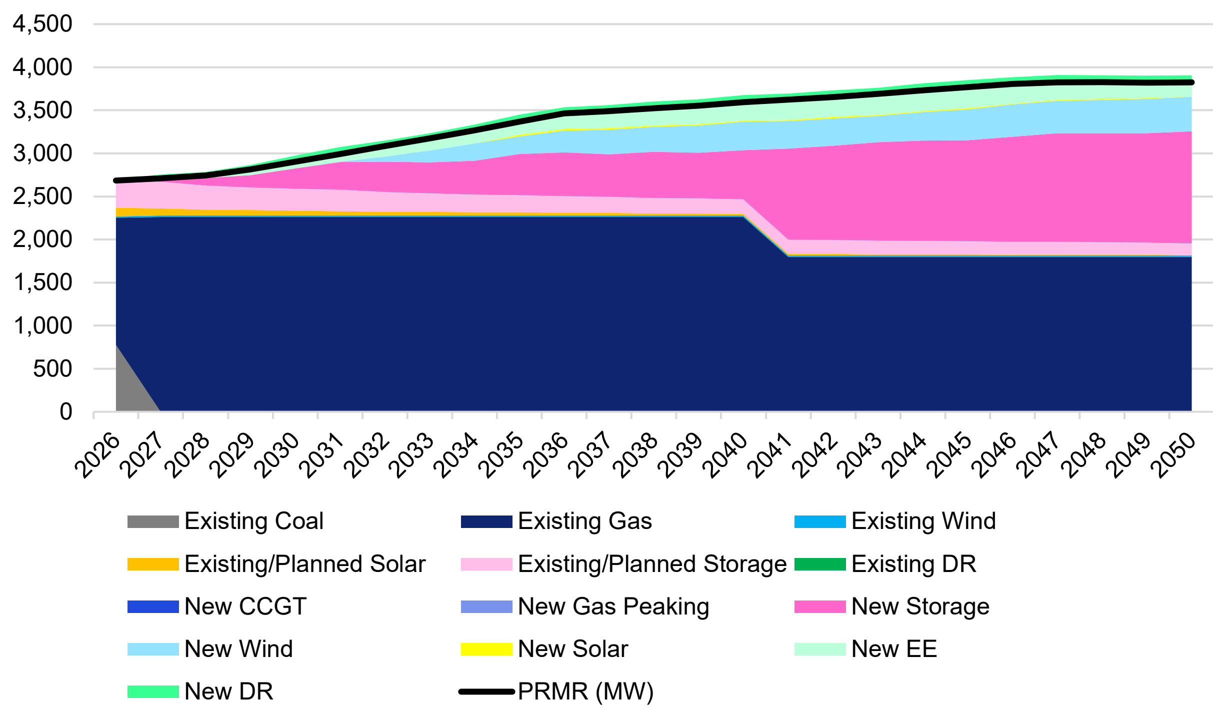


Figure 9-55: High Regulatory: Environmental – Mid Data Center Load - Winter Firm Capacity (MW)

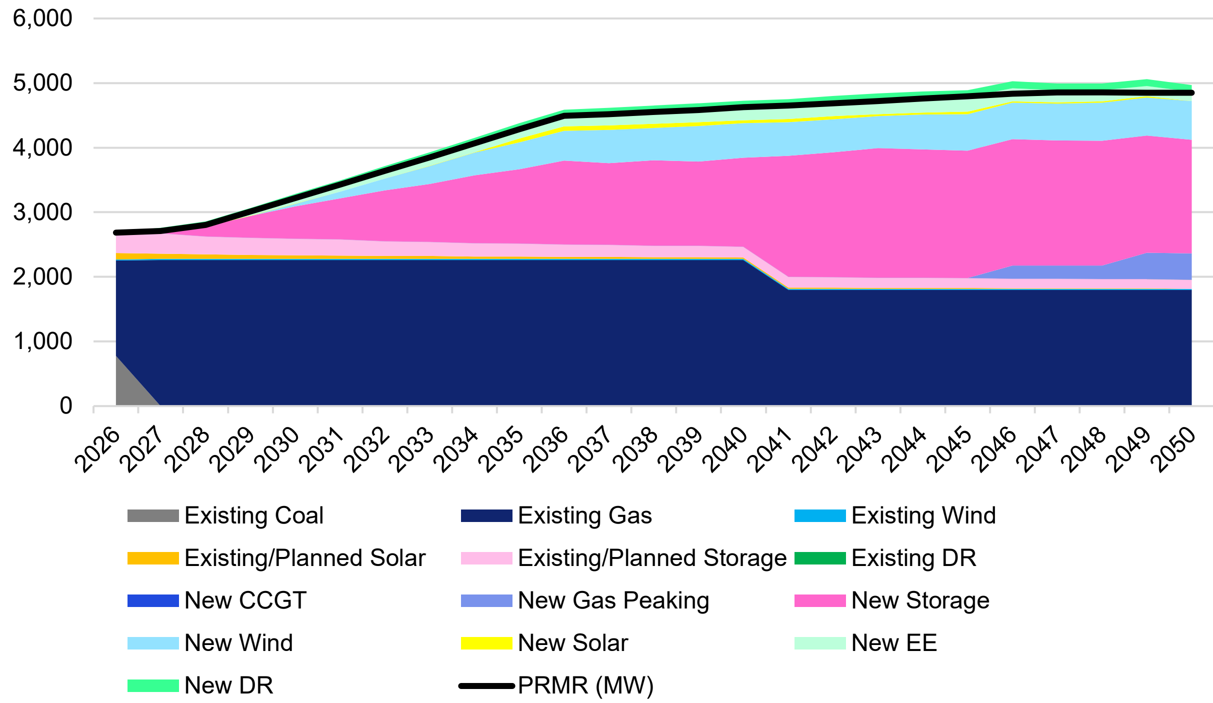
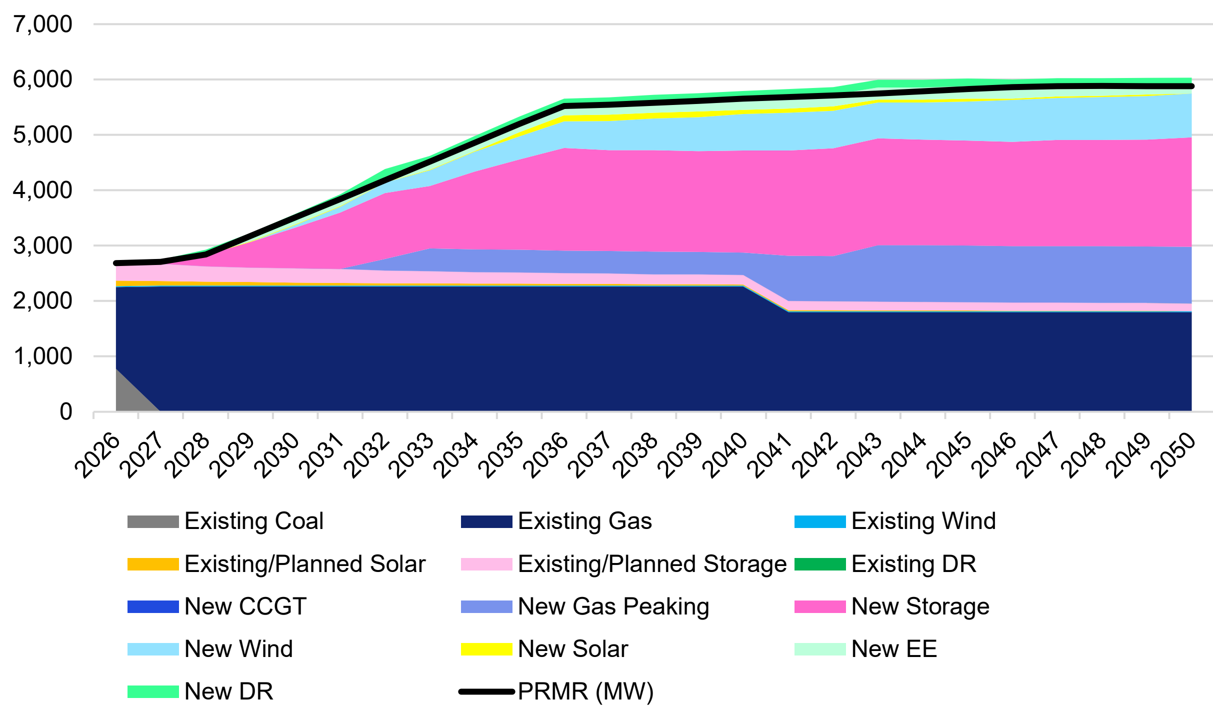


Figure 9-56: High Regulatory: Environmental – High Data Center Load - Winter Firm Capacity (MW)



The energy positions are shown in Figure **9-57** through Figure 9-60. Wind becomes a substantial energy resource in all portfolios under the High Regulatory: Environmental Scenario.

Figure 9-57: High Regulatory: Environmental – No Data Center Load – Energy Position

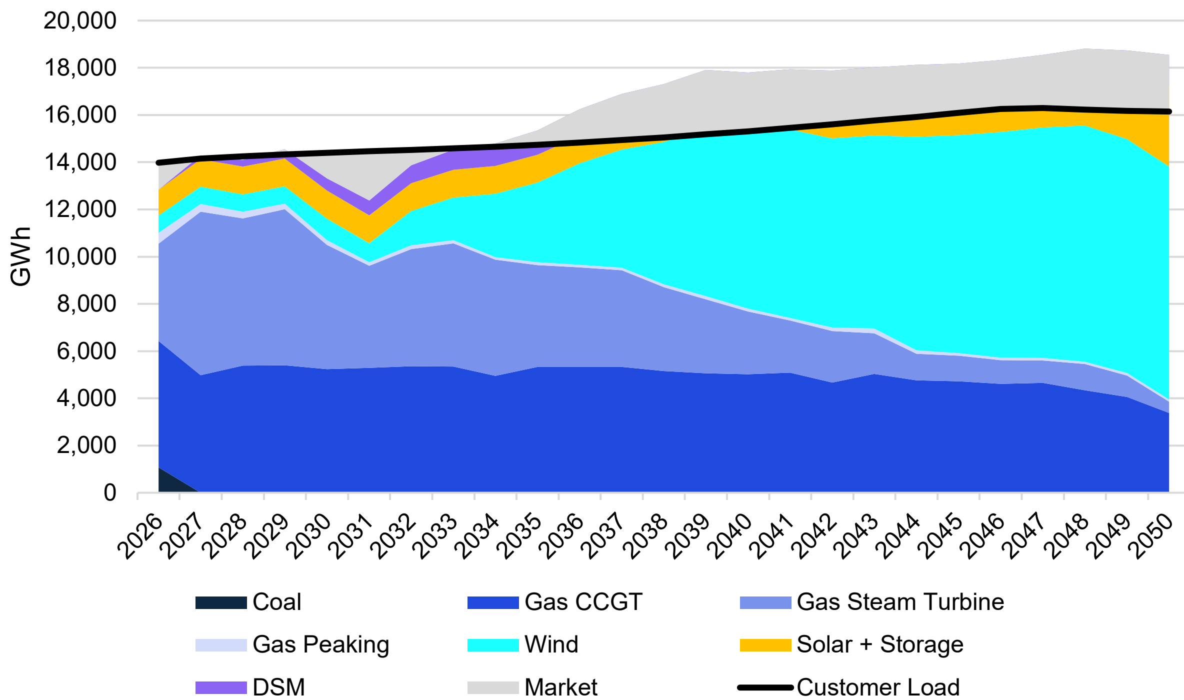


Figure 9-58: High Regulatory: Environmental – Low Data Center Load – Energy Position

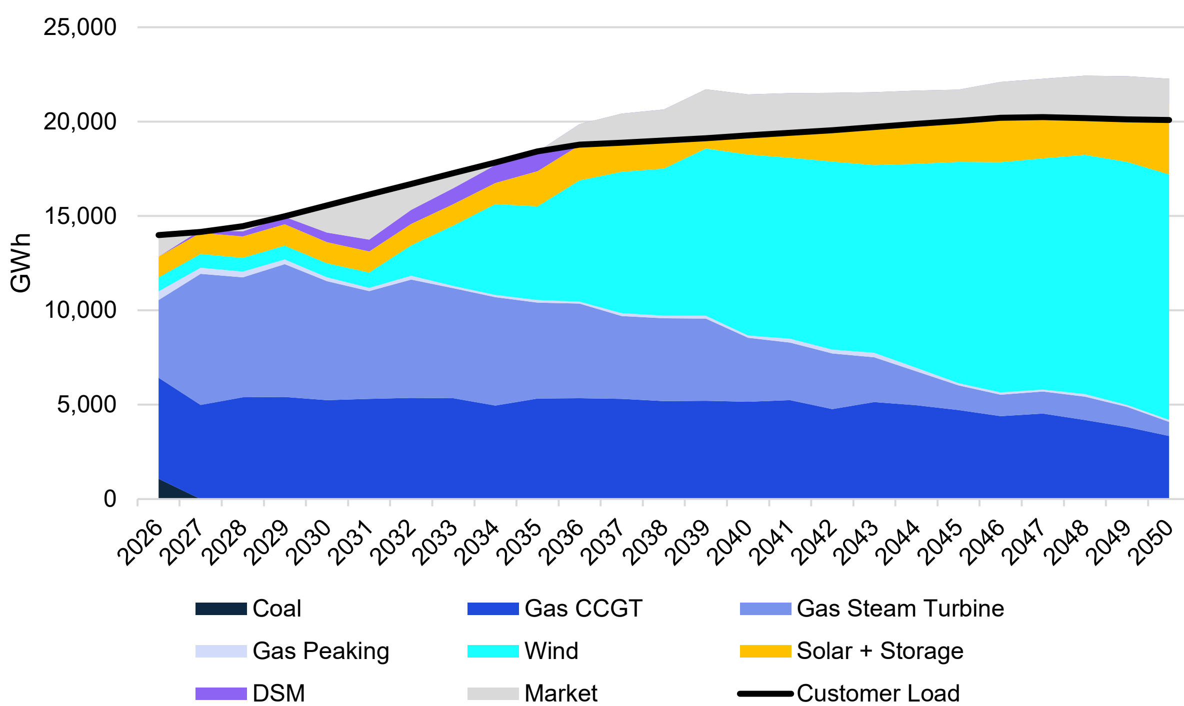


Figure 9-59: High Regulatory: Environmental – Mid Data Center Load – Energy Position

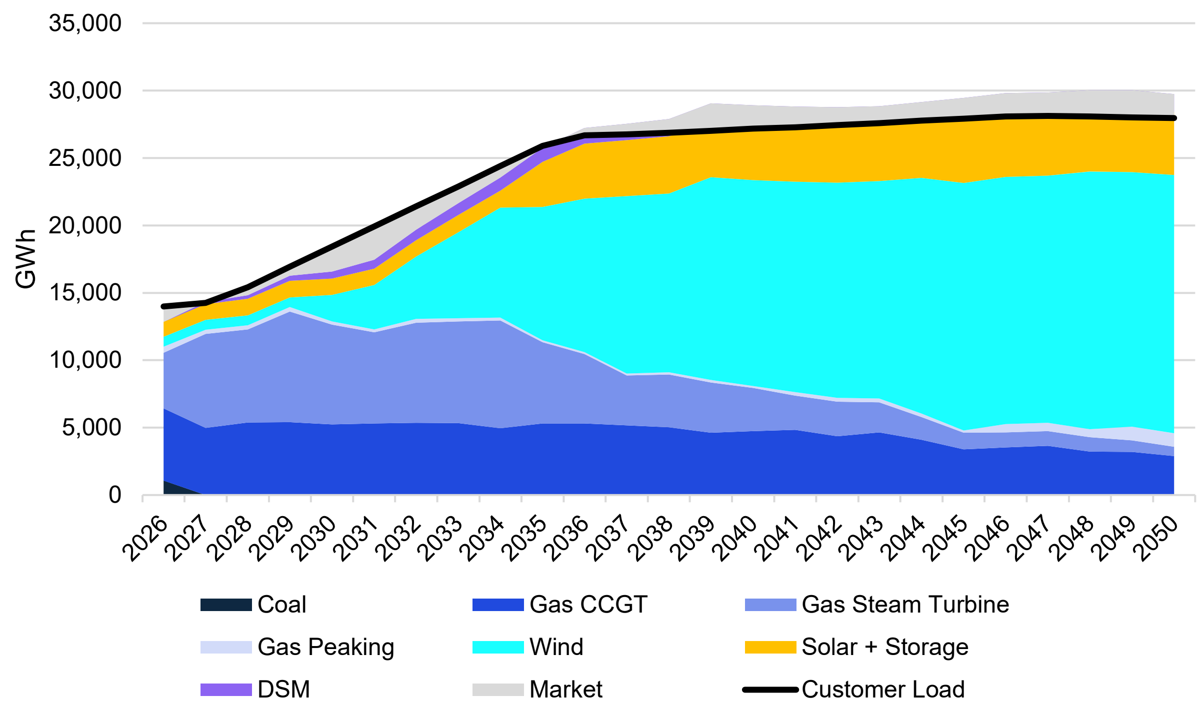
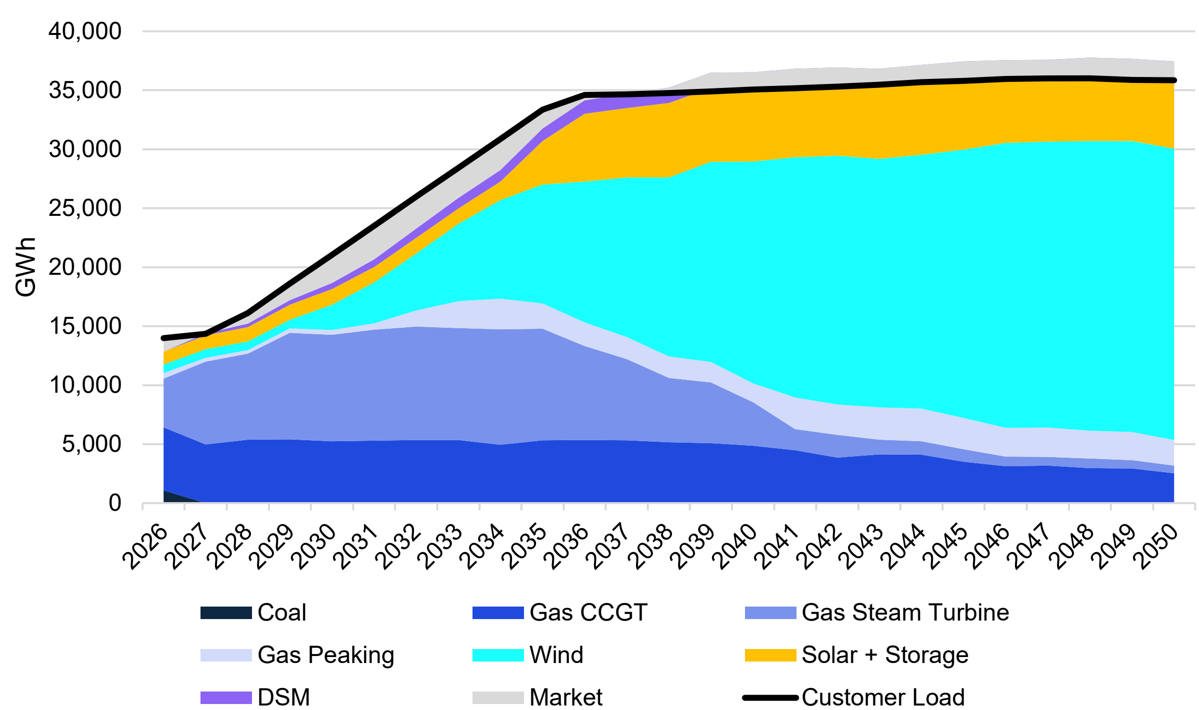


Figure 9-60: High Regulatory: Environmental – High Data Center Load – Energy Position

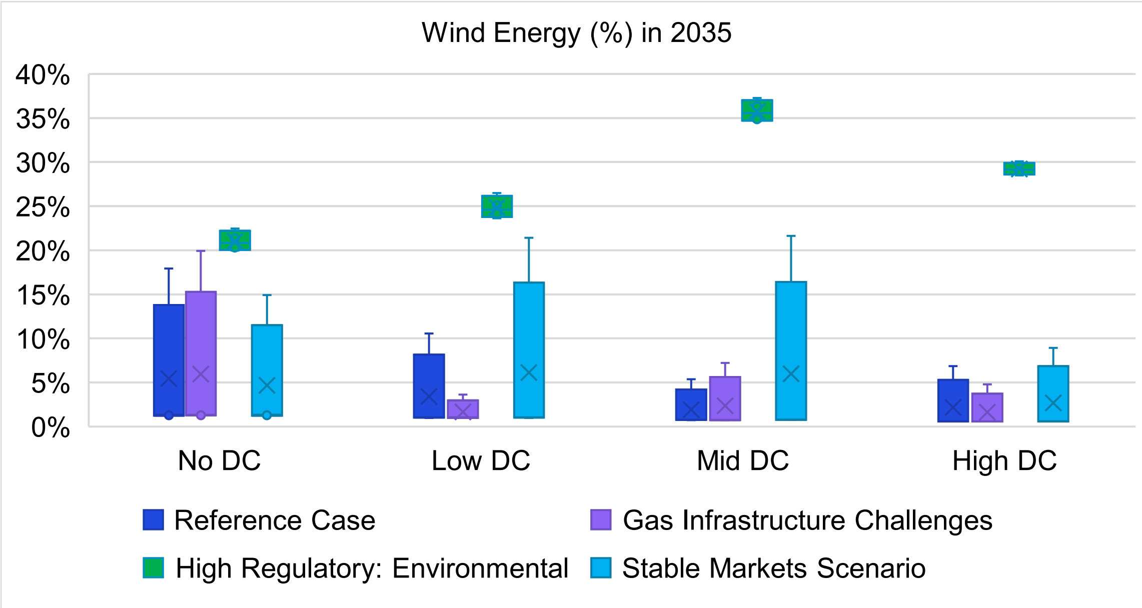


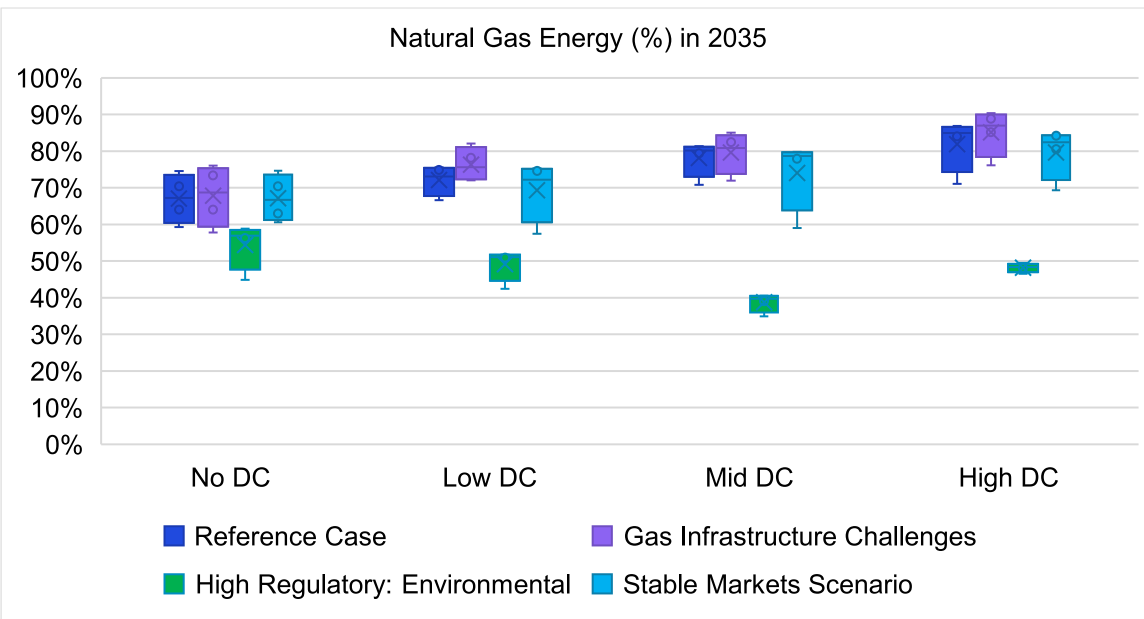
By 2030, the percent of total retail sales is 4% met by energy efficiency in the No Data Center: High Regulatory: Environmental, and 3% met by energy efficiency in the High Data Center: High Regulatory: Environmental. Customers are served by another 36% of their requirements from combined cycle, 36% steam, and 1% gas peaking in the No Data Center: High Regulatory: Environmental; compared to 25% combined cycle, 43% steam, and 2% gas peaking in the High Data Center: High Regulatory: Environmental. Wind, solar, and storage are 15% of customer load in the No Data Center: High Regulatory: Environmental and 16% in the High Data Center: High Regulatory: Environmental.

By 2035, the percent of total retail sales is 7% met by energy efficiency in the No Data Center: High Regulatory: Environmental, and 3% met by energy efficiency in the High Data Center: High Regulatory: Environmental. Customers are served by another 36% of their requirements from combined cycle, 29% steam, and 1% gas peaking in the No Data Center: High Regulatory: Environmental; compared to 16% combined cycle, 28% steam, and 6% gas peaking in the High Data Center: High Regulatory: Environmental. Wind, solar, and storage are 31% of customer load in the No Data Center: High Regulatory: Environmental and 41% in the High Data Center: High Regulatory: Environmental.

As shown in Figure 9-61, in the High Regulatory: Environmental Scenarios, wind energy replaces natural gas. In the Figure, the values on the x-axis represent the portfolios exposed to the four scenarios. The energy is a generation percent of total requirements (energy, storage purchases, and sales).

Figure 9-61: Wind versus Natural Gas Energy in 2035





The demand response and energy efficiency resources selected in Figure 9-62 follow similar patterns to the portfolios previously mentioned. However, DR battery is selected in all cases. The High Data Center load also triggers the need for DR Capacity Bidding. The portfolios also select additional energy efficiency resources, including Res_Tier2 vintage for larger data center loads.

Figure 9-62: High Regulatory: Environmental Demand-Side Resource Selections

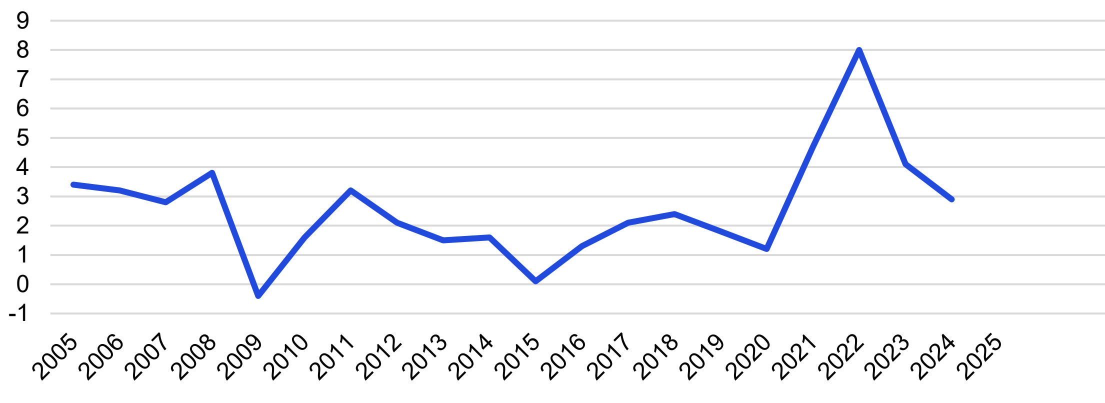
	No Data Center	Low Data Center	Mid Data Center	High Data Center
ENERGY EFFICIENCY				
C&I V1	X	X	X	X
C&I V2	X	X	X	X
C&I V3	X	X	X	X
Res BEH Tier1 V1	X	X	X	X
Res BEH Tier1 V2	X	X	X	X
Res BEH Tier1 V3	X	X	X	X
Res Tier2 V1				
Res Tier2 V2			X	X
Res Tier2 V3	X	X	X	X
IQW V1	X	X	X	X
IQW V2	X	X	X	X
IQW V3	X	X	X	X
IQ HEAR V1	X	X	X	X
IQ HEAR V2	X	X	X	X
IQ HEAR V3	X	X	X	X
DEMAND RESPONSE				
DR Thermostat	X	X	X	X
DR Battery	X	X	X	X
DR Load Curtailment	X	X	X	X
DR Capacity Bidding				X
DR BDR	X	X	X	X
DR PTR	X	X	X	X
DR TOU	X	X	X	X

Stable Market Scenario

Within the past few years, markets have experienced inflationary pressures, as seen in Figure 9-63. Capital costs for new resources have increased dramatically. For example, the 2025 IRP assumed that in 2026, the capital cost of a new combined-cycle plant would be $2,700/kW-year and that of a new wind plant would be $2,500/kW-year. Compare that to the 2022 IRP, which assumed $1,100/kW-year for a combined cycle and $1,400/kW-year for a wind facility.

The Stable Market Scenario represents a return to a lower cost environment. Capital costs are lower, natural gas prices are depressed, and load is lower.

Figure 9-63: Average Annual Inflation (%)[61]



The installed capacity under the Stable Markets Scenario is identified in Figure 9-64 through Figure 9-68. Similar to the other four scenarios, the Stable Markets portfolios rely on demand response and energy efficiency. Battery storage fits capacity needs. A combined cycle is only brought online by 2035 in the High Data Center load profile; combustion turbines play a comparatively larger capacity role. Low market prices are driving investment in storage and combustion turbines.

61 Historical Inflation Rates: 1914-2025

Figure 9-64: Stable Market Scenario – Installed Capacity (MW) by Resource Type and Load Case

		2030	2035	2040	2045
Demand Response	No Data Center Load	48	61	64	66
	Low DC Load	129	153	153	152
	Mid DC Load	130	156	158	157
	High DC Load	129	153	153	152
Energy Efficiency	No Data Center Load	98	191	267	303
	Low DC Load	98	191	267	303
	Mid DC Load	98	191	267	303
	High DC Load	98	191	267	303
Battery Storage	No Data Center Load			20	120
	Low DC Load	40	120	140	200
	Mid DC Load	400	720	780	940
	High DC Load	780	960	1,020	1,020
Gas CCGT	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load		700	700	1,400
Gas CT	No Data Center Load				480
	Low DC Load		480	480	960
	Mid DC Load		960	1,200	1,680
	High DC Load		1,440	1,680	1,680
Gas Reciprocating Engines	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				
Solar	No Data Center Load				
	Low DC Load	50	50	50	50
	Mid DC Load	100	100	100	100
	High DC Load	100	100	100	100
Wind	No Data Center Load				
	Low DC Load				
	Mid DC Load				
	High DC Load				

Cumulative installed capacity is in Figure 9-65 through Figure 9-68. The figures visualize the selection of combustion turbines over combined cycles.

Figure 9-65: Stable Markets Scenario – No Data Center Load – Cumulative Installed Capacity (MW)

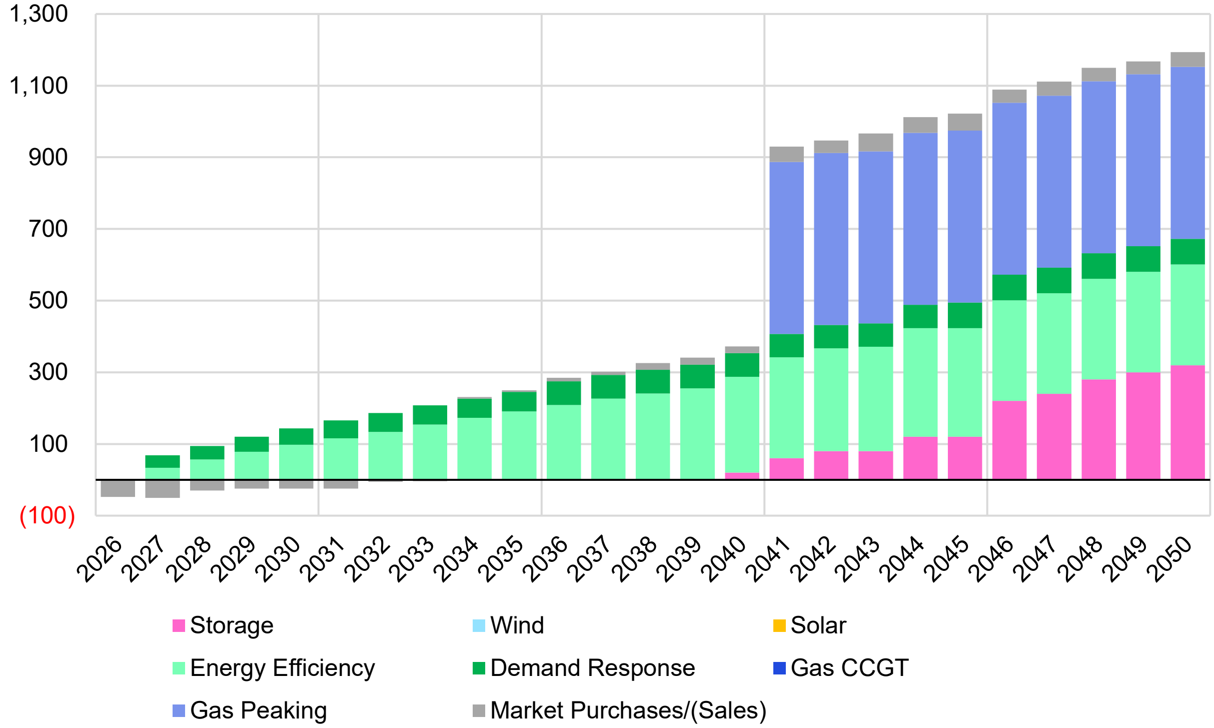


Figure 9-66: Stable Markets Scenario – Low Data Center Load – Cumulative Installed Capacity (MW)

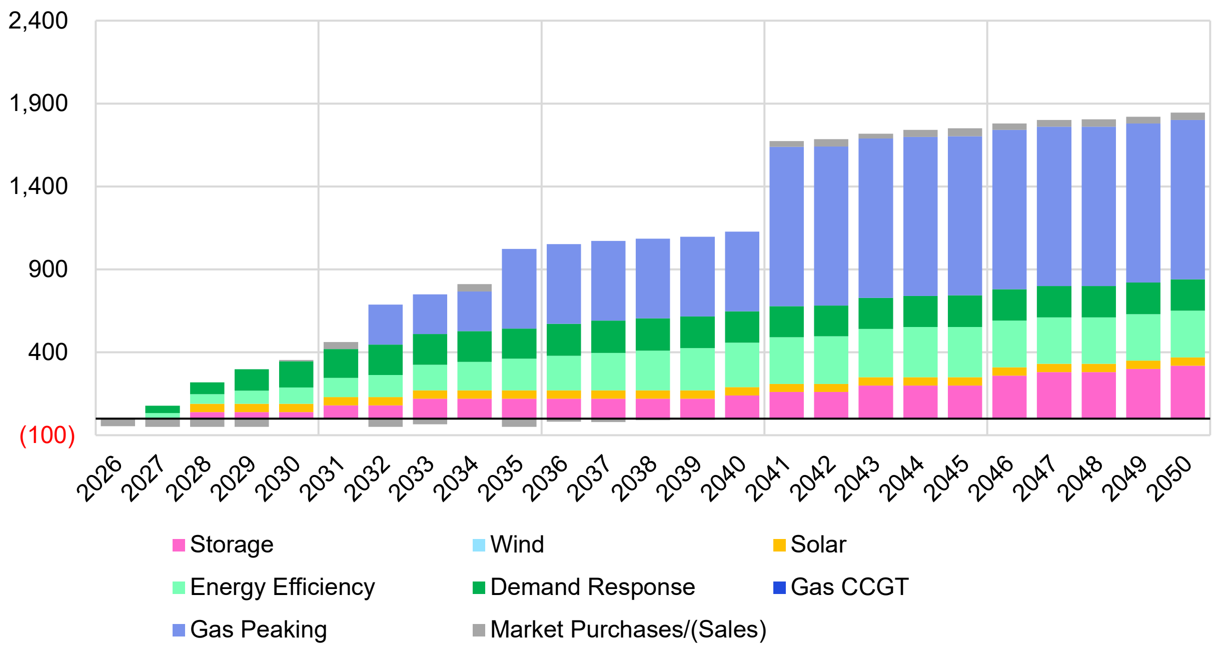


Figure 9-67: Stable Markets Scenario – Mid Data Center Load – Cumulative Installed Capacity (MW)

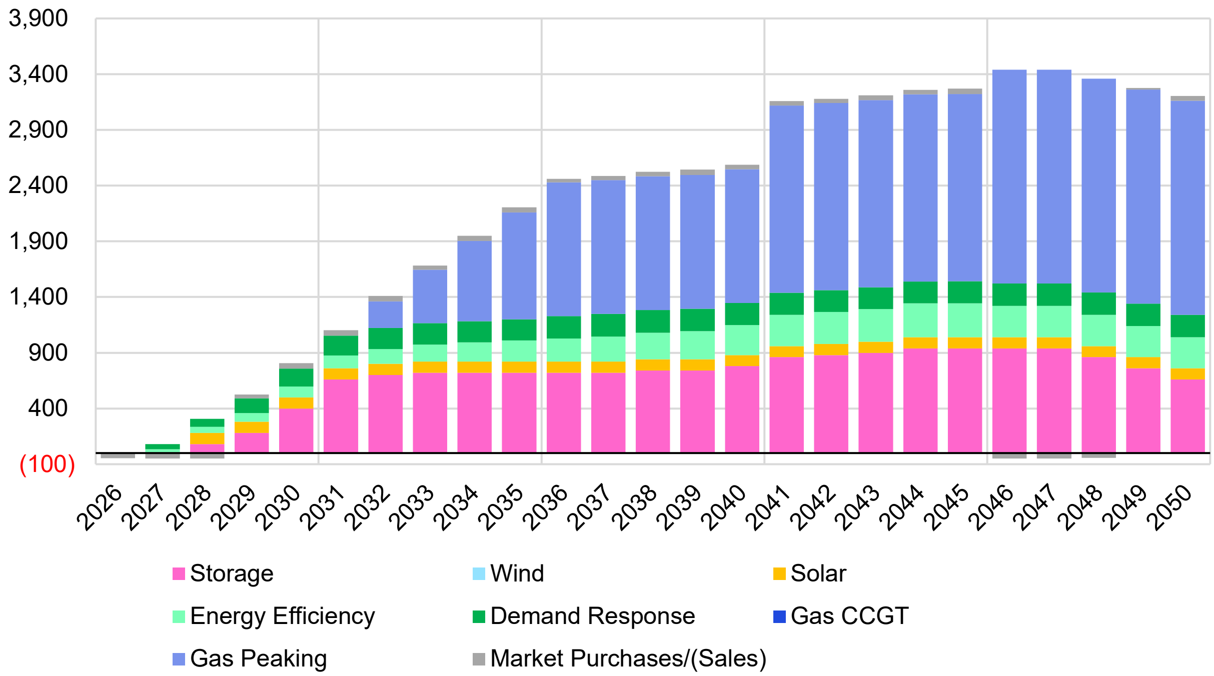
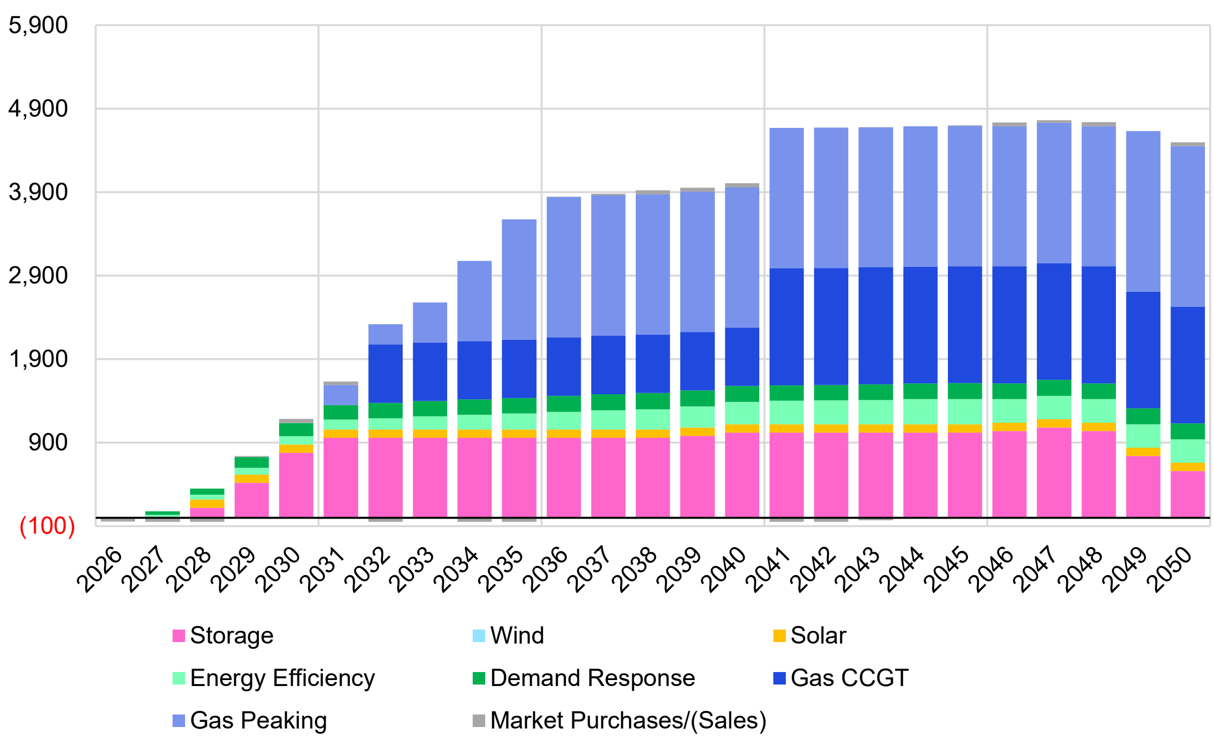


Figure 9-68: Stable Markets Scenario – High Data Center Load – Cumulative Installed Capacity (MW)



Short-term capacity additions are in Figure 9-69 through Figure 9-72. As in the other scenarios, without large load additions, native Indiana load growth is met through demand response and energy efficiency. Large load additions trigger additional selections of battery storage and combustion turbines.

Figure 9-69: Stable Markets Scenario – No Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	54	56	61	68	77	83	85	86	87
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage									
Gas CCGT									
Gas CT									
Gas Reciprocating Engines									
Solar									
Wind									

Figure 9-70: Stable Markets Scenario – Low Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	152	184	204	214	216	217	218
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		40	40	40	80	80	120	120	120
Gas CCGT									
Gas CT						240	240	240	480
Gas Reciprocating Engines									
Solar		50	50	50	50	50	50	50	50
Wind									

Figure 9-71: Stable Markets Scenario – Mid Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	153	186	206	217	219	221	223
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		80	180	400	660	700	720	720	720
Gas CCGT									
Gas CT						240	480	720	960
Gas Reciprocating Engines									
Solar		100	100	100	100	100	100	100	100
Wind									

Figure 9-72: Stable Markets Scenario – High Data Center Load – Near-term Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Response	63	87	152	184	204	214	216	217	218
Energy Efficiency	34	57	78	98	116	133	154	173	191
Battery Storage		120	420	780	960	960	960	960	960
Gas CCGT						700	700	700	700
Gas CT					240	240	480	960	1,440
Gas Reciprocating Engines									
Solar		100	100	100	100	100	100	100	100
Wind									

The portfolios also bring online solar. The costs of solar and wind are lower in this scenario. For example, in the Reference Case, the levelized cost of energy for solar and wind is $70/MWh and $73/MWh, respectively, in 2026; in this scenario, levelized costs are $42/MWh and $53/MWh, respectively.

Firm capacity values for the Stable Markets Scenario are identified in Figure 9-73 through Figure 9-76.

Figure 9-73: Stable Markets Scenario – No Data Center Load – Winter Firm Capacity (MW)

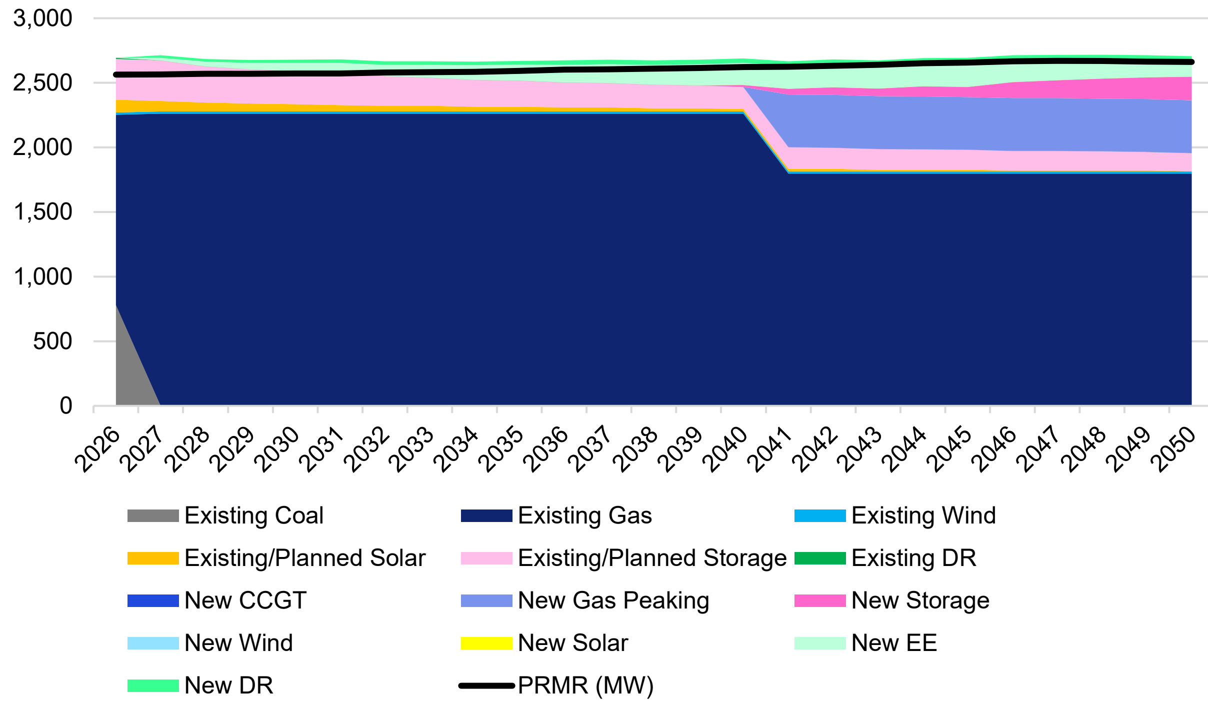


Figure 9-74: Stable Markets Scenario – Low Data Center Load – Winter Firm Capacity (MW)

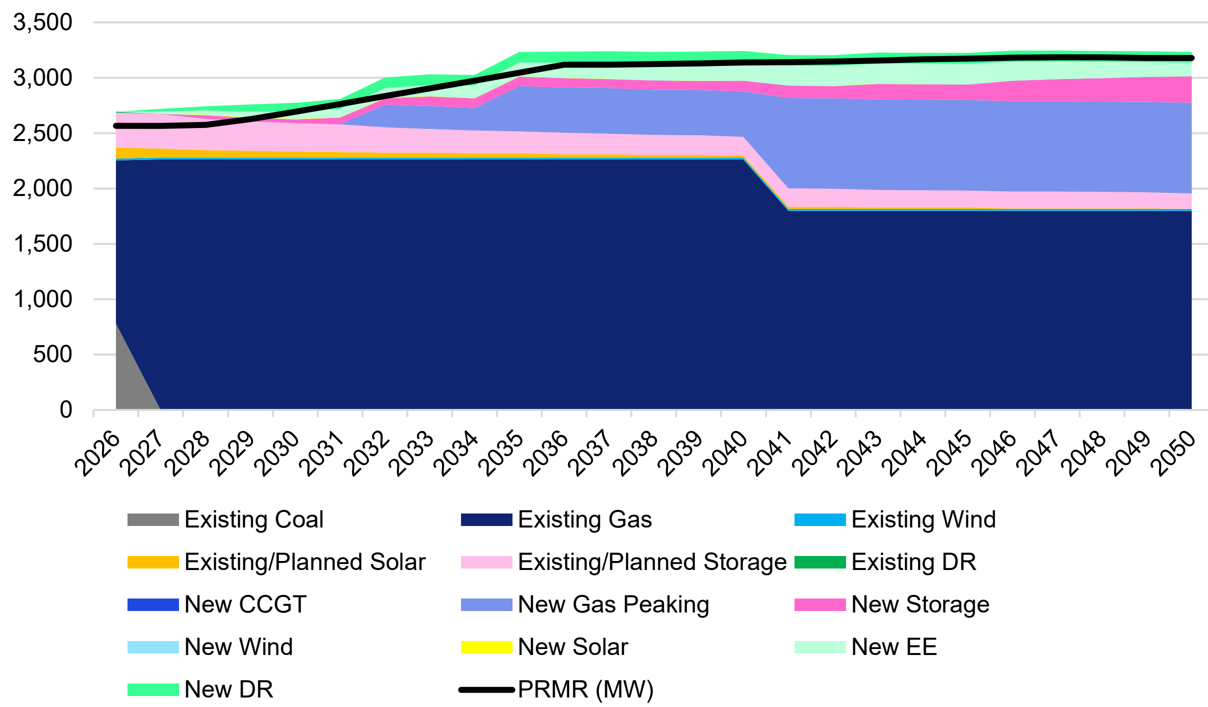


Figure 9-75: Stable Markets Scenario – Mid Data Center Load– Winter Firm Capacity (MW)

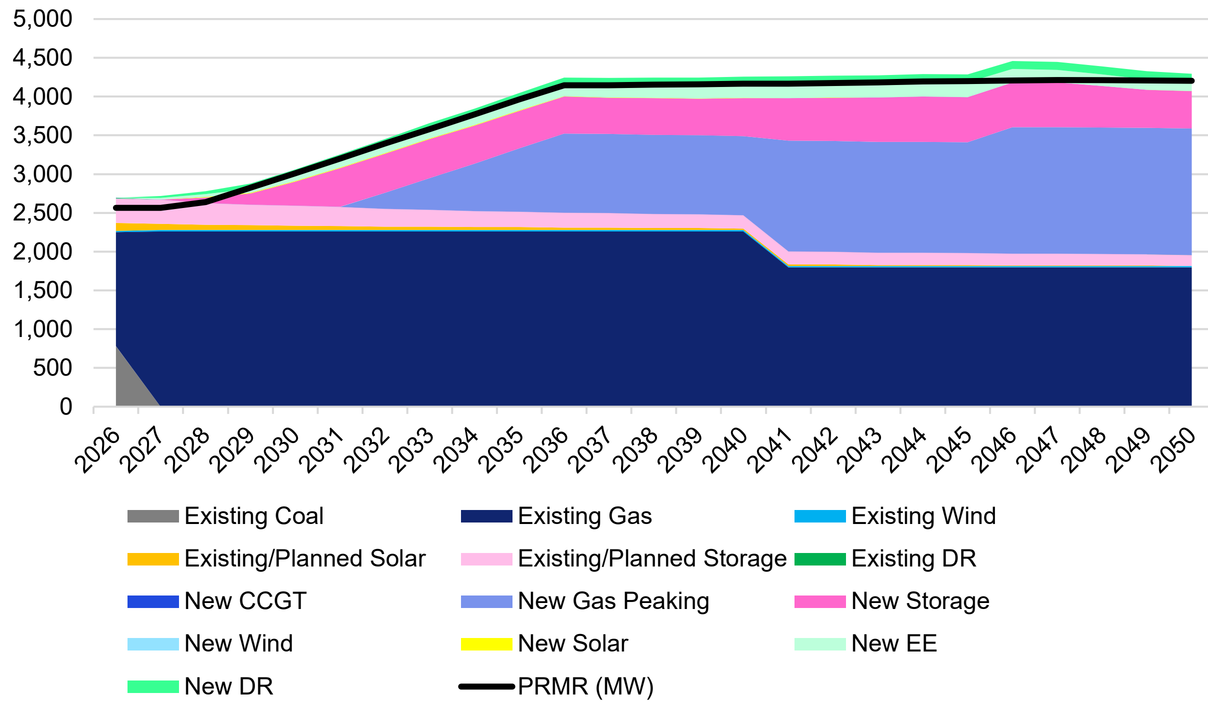
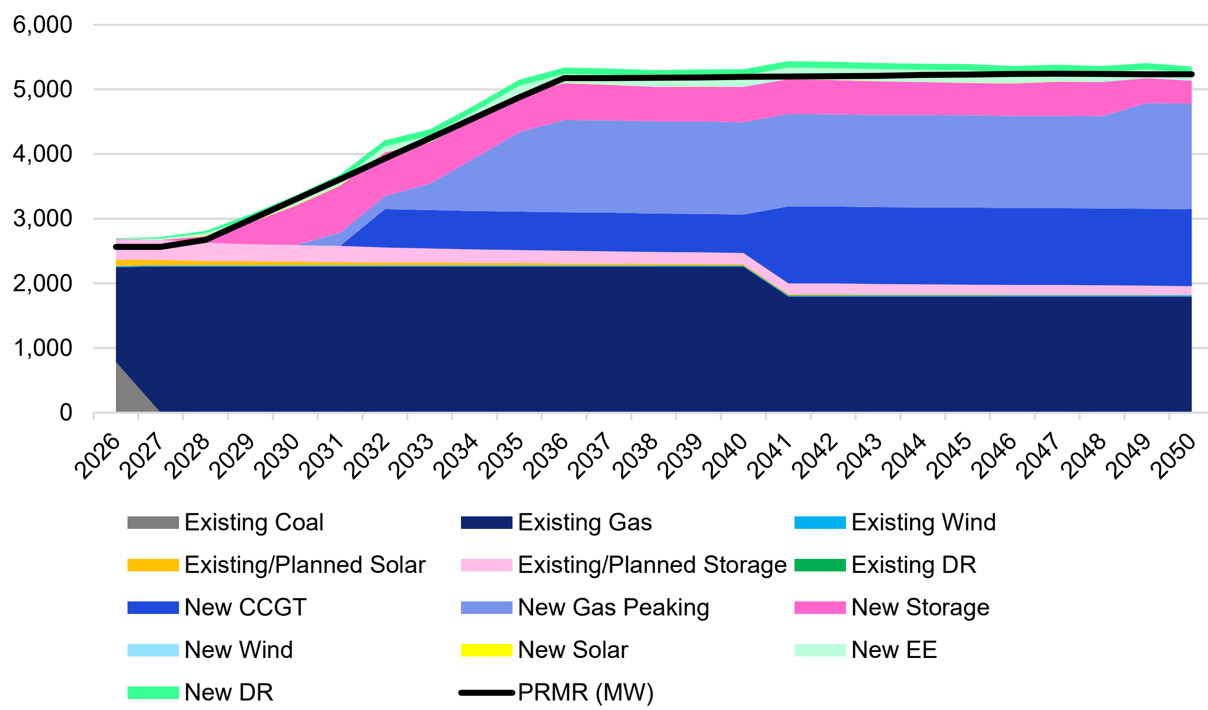


Figure 9-76: Stable Markets Scenario – High Data Center Load - Winter Firm Capacity (MW)



Stable Market Scenario energy positions are identified in Figure 9-77 through Figure 9-80.

Figure 9-77: Stable Markets Scenario – No Data Center Load – Energy Position

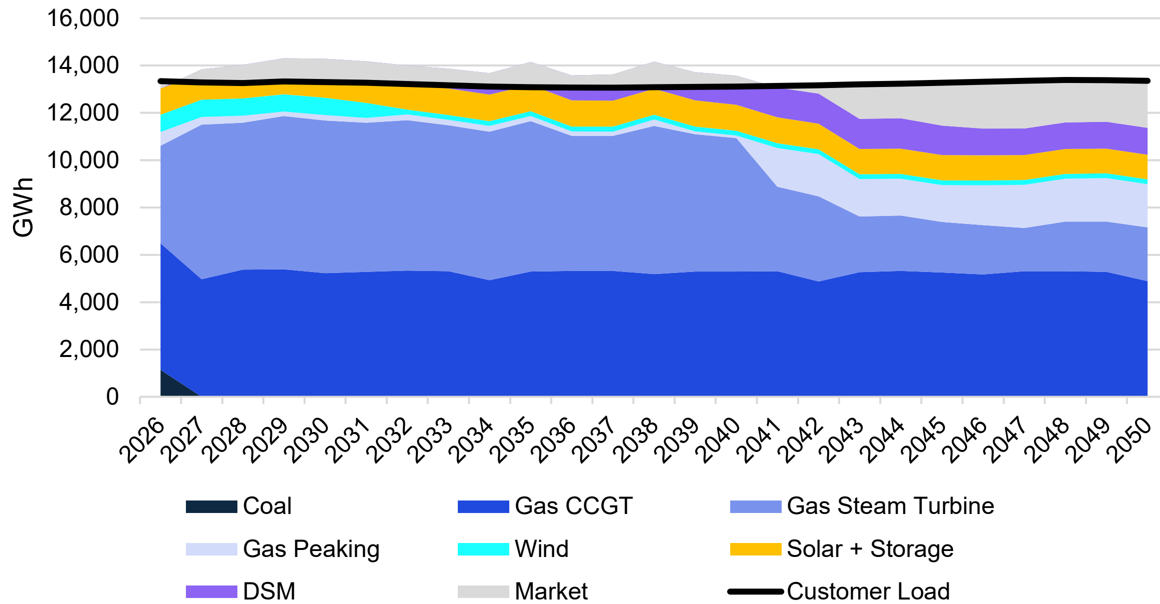


Figure 9-78: Stable Markets Scenario – Low Data Center Load – Energy Position

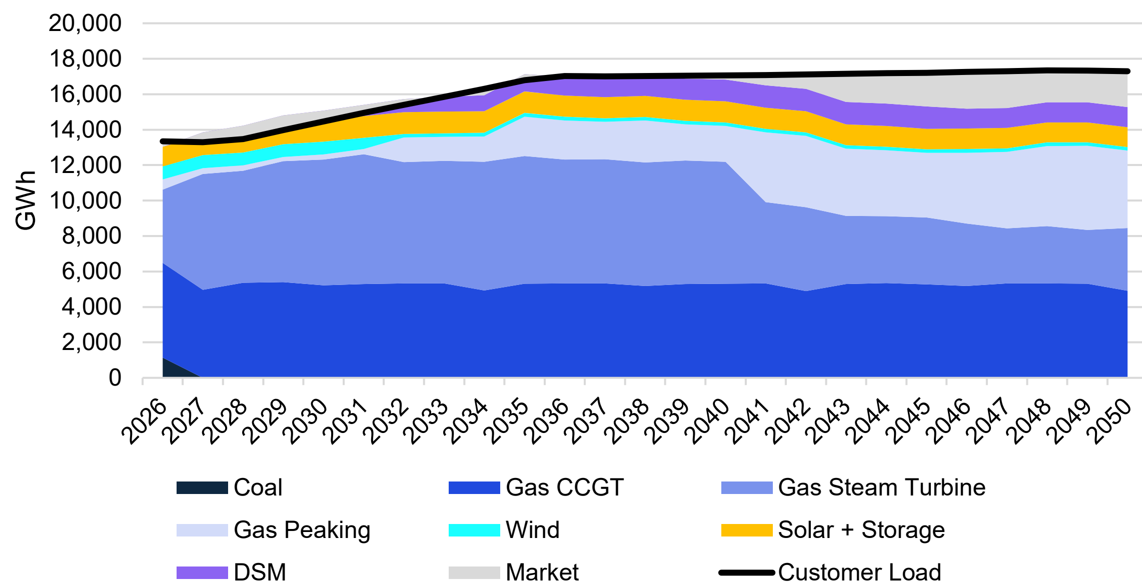


Figure 9-79: Stable Markets Scenario – Mid Data Center Load – Energy Position

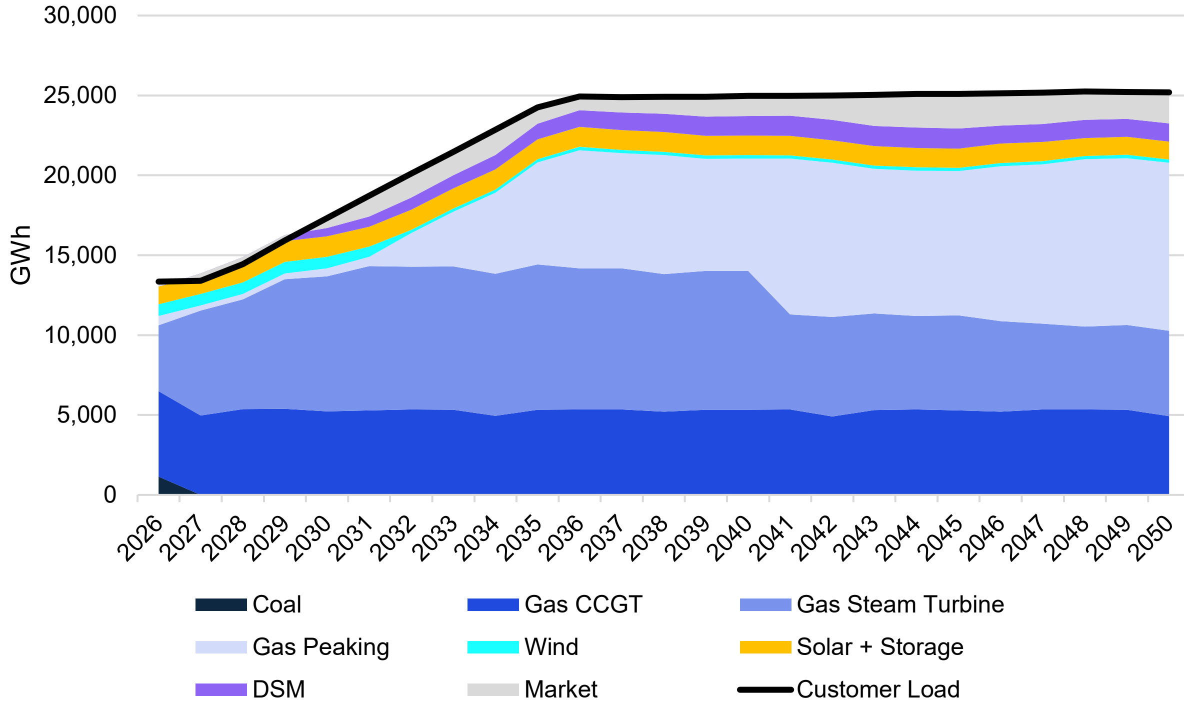
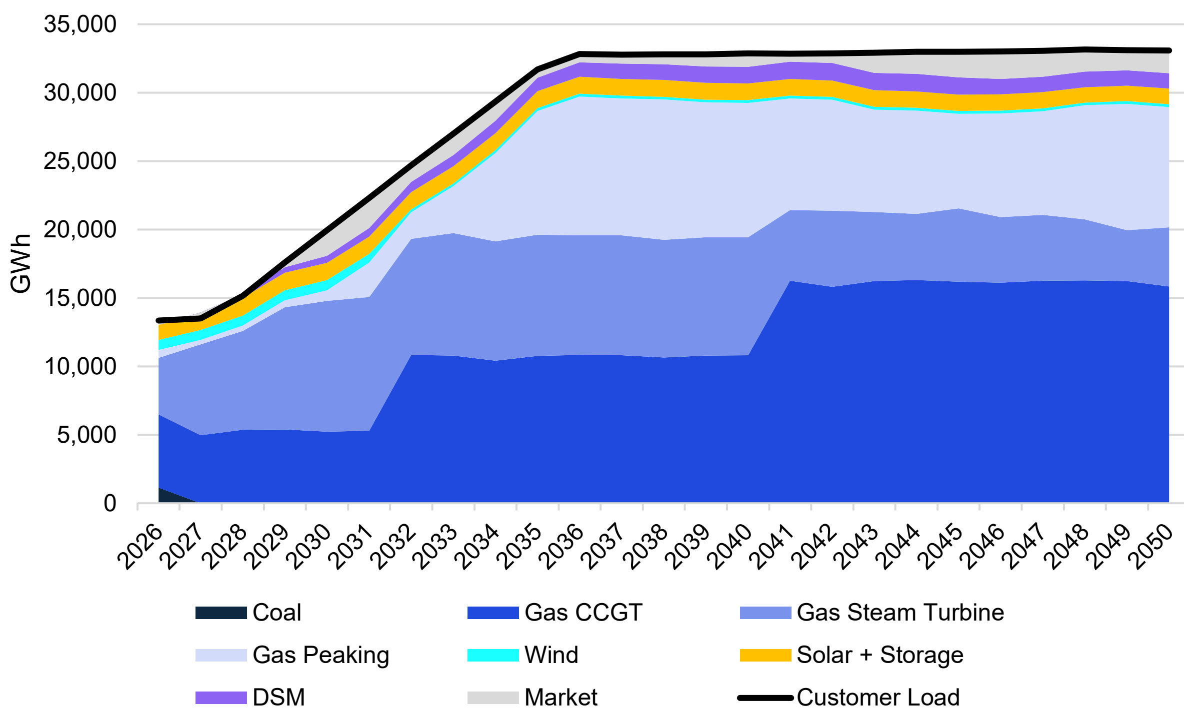


Figure 9-80: Stable Markets Scenario – High Data Center Load – Energy Position



By 2030, customer load is served using 4% energy efficiency in the No Data Center: Stable Markets and 3% in the High Data Center: Stable Markets. Gas combined cycle energy is 39% combined cycle, 49% steam, and 2% gas peaking in the No Data Center: Stable Markets; compared to 26% combined cycle, 48% steam, and 4% gas peaking in the High Data Center: Stable Markets. Wind, solar, and storage are 14% in the No Data Center: Stable Markets and 10% in the High Data Center: Stable Markets. The remainder of the energy requirement for each portfolio is satisfied using energy market purchases.

Demand response is in Figure 9-81. Demand response again plays a significant role in meeting new capacity needs. In the No Data Center case, overall demand response selection is lower, and native load growth within Indiana is lower. Commercial and residential behavioral packages are chosen, as seen in other portfolios.

Figure 9-81: Stable Markets Scenario Demand-Side Resource Selections

	No Data Center	Low Data Center	Mid Data Center	High Data Center
ENERGY EFFICIENCY				
C&I V1	X	X	X	X
C&I V2	X	X	X	X
C&I V3	X	X	X	X
Res BEH Tier1 V1	X	X	X	X
Res BEH Tier1 V2	X	X	X	X
Res BEH Tier1 V3	X	X	X	X
Res Tier2 V1				
Res Tier2 V2				
Res Tier2 V3				
IQW V1	X	X	X	X
IQW V2	X	X	X	X
IQW V3	X	X	X	X
IQ HEAR V1	X	X	X	X
IQ HEAR V2	X	X	X	X
IQ HEAR V3	X	X	X	X
DEMAND RESPONSE				
DR Thermostat	X	X	X	X
DR Battery			X	
DR Load Curtailment		X	X	X
DR Capacity Bidding				
DR BDR		X	X	X
DR PTR		X	X	X
DR TOU	X	X	X	X

9.2.3 Capacity Expansion Comparison

170 IAC 4-7-4(3), 170 IAC 4-7-4(5), 170 IAC 4-7-8(b)(1), 170 IAC 4-7-8(c)(4)(D)-(E), and 170 IAC 4-7-8(c)(5)

The installed capacity across portfolios through 2035 is shown in Figure 9-82. Major points are included below.

1. ***No Data Centers***
    a. Wind and solar is needed in a High Regulatory world, where 75 MW should be acquired by 2030/2031.
    b. Under current market conditions, 275 MW of demand management and energy efficiency is needed by 2030, and 300 MW by 2031.
    c. 20 MW of storage is needed by 2030/2031
    d. No natural gas is added.
2. ***Low Data Centers***
    a. Consider adding 50 to 100 MW of solar and an additional 350 MW of wind, should market conditions deviate from the current conditions.
    b. Install 300 to 650 MW of storage by 2030.
    c. In a challenged gas world, consider a combined cycle by 2030, and in a business-as-usual world, by 2032.
3. ***Mid Data Centers***
    a. If the market environment begins shift from current conditions, consider adding 50 to 100 MW of solar prior to 2030. If policies look like those in 2020s, then also consider adding up to 350 MW of wind.
    b. No matter the large load, acquire around 300 MW of demand side resources by 2031.
    c. Build 300 MW to 650 MW of storage by 2030.
    d. No gas peaking until 2033 in all scenarios except Stable Market, which installs a combustion turbine in 2032.
    e. In 2032, a 700 MW CCGT comes online in the Reference Case. In the Gas Infrastructure Challenges scenario, a combined cycle comes online in 2030, because more economic energy from the lower heat rate is needed
4. ***High Data Centers***
    a. By 2035, storage installations could range from 400 MW to 1.8 GW, peaking installations from 100 MW to 1 GW, and combined cycles from 700 MW to 1.4 GW.

Figure 9-82: Cumulative New Installed Capacity through 2035 (MW)

		DR	EE	Storage	Gas CCGT	Gas Peaking	Solar	Wind
No Data Center Load	Reference	223	191	100	0	0	0	0
	Scenario 2	223	191	100	0	0	0	0
	Scenario 3	223	191	120	0	0	25	900
	Scenario 4	87	191	0	0	0	0	0
Low Data Center Load (500 MW)	Reference	218	191	420	0	480	0	0
	Scenario 2	218	191	160	700	0	0	0
	Scenario 3	223	191	780	0	0	350	1,350
	Scenario 4	218	191	120	0	480	50	0
Mid Data Center Load (1,500 MW)	Reference	200	191	860	700	480	0	0
	Scenario 2	223	191	380	1,400	108	50	0
	Scenario 3	223	191	1,840	0	0	1,050	2,750
	Scenario 4	223	191	720	0	960	100	0
High Data Center Load (2,500 MW)	Reference	218	191	640	2,100	294	0	0
	Scenario 2	223	191	620	2,800	0	25	0
	Scenario 3	223	191	2,480	0	480	1,225	2,800
	Scenario 4	218	191	960	700	1,440	100	0

9.3 Scorecard Evaluation Results

170 IAC 4-7-4(3), 170 IAC 4-7-4(5), 170 IAC 4-7-8(b)(1), 170 IAC 4-7-8(c)(3)-(5), and 170 IAC 4-7-8(c)(7)

9.3.1 Overview

The IRP Scorecard has four categories: 1) Affordability, 2) Reliability, Resiliency and Stability 3) Risk & Opportunity and 4) Environmental. The Scorecard metrics, or key performance indicators within each of the four categories, are designed to be consistent with the “Five Pillars of Electric Service” as identified in Ind. Code § 8-1-2-0.6. The metrics are also designed to compare performance between portfolios and scenarios. The definition of the Scorecard metrics are shown below. The results of the scorecard are in Figure 9-83. Results are detailed in the following sections.

Figure 9-83: 2025 IRP Scorecard Results

		AFFORDABILITY				RELIABILITY, RESILIENCY, AND STABILITY					RISK & OPPORTUNITY				ENVIRONMENTAL	
Data Center Case	Portfolio	10-Year Levelized Supply Cost	25-Year Supply Cost	10-Year PVRR	25-Year PVRR	Market Purchases + Sales	25-yr energy purchases, % of load	25-yr energy sales, % of load	Dispatchable Capacity, Percent of Peak (2035)	Dispatchable FIRM Capacity , Percent of Peak (2035)	Opportunity (Mean - P5)	Risk (P95-Mean)	Enviro. Scenario Risk	Avg. % Difference from Optimal	Total CO2 Emissions (25-yr)	Carbon Intensity (25-yr avg.)
	Units →	$2026/MWh	$2026/MWh	2026$MM	2026$MM	%	%	%	%	%	%	%	2026$MM	%	Million Tons	lb/MWh
No Data Center Load	Reference Case	$149	$161	$5,126	$10,092	26%	16%	10%	111%	90%	17%	18%	$234	0%	147	772
	Gas Infrastructure Challenges	$149	$162	$5,154	$10,161	21%	13%	8%	111%	90%	17%	18%	$237	4%	146	766
	High Regulatory: Environmental	$156	$188	$5,906	$15,455	25%	11%	14%	111%	91%	7%	9%	$0	52%	99	523
	Stable Markets Scenario	$149	$161	$5,126	$10,070	27%	18%	9%	111%	90%	17%	19%	$57	0%	153	805
Low Data Center	Reference Case	$144	$151	$5,985	$12,654	23%	15%	8%	121%	99%	14%	18%	$239	3%	183	806
	Gas Infrastructure Challenges	$148	$153	$6,400	$13,047	21%	11%	10%	118%	98%	12%	15%	$970	7%	177	777
	High Regulatory: Environmental	$153	$180	$7,099	$19,827	26%	12%	14%	117%	96%	6%	8%	$0	53%	111	486
	Stable Markets Scenario	$145	$151	$6,020	$12,699	23%	15%	8%	119%	97%	15%	18%	$196	1%	194	854
Mid Data Center	Reference Case	$138	$139	$7,971	$18,187	17%	12%	5%	122%	102%	11%	16%	$658	3%	247	812
	Gas Infrastructure Challenges	$139	$140	$8,220	$18,499	17%	10%	7%	117%	99%	11%	15%	$1,217	6%	232	763
	High Regulatory: Environmental	$151	$174	$10,236	$30,040	21%	10%	11%	118%	98%	4%	6%	$0	60%	117	384
	Stable Markets Scenario	$138	$139	$7,967	$18,266	17%	12%	4%	121%	100%	12%	18%	$209	2%	278	914
High Data Center	Reference Case	$134	$132	$9,975	$23,754	15%	10%	5%	118%	102%	11%	15%	$1,434	3%	295	779
	Gas Infrastructure Challenges	$135	$133	$10,132	$24,032	14%	8%	7%	125%	109%	10%	14%	$1,851	5%	292	770
	High Regulatory: Environmental	$145	$164	$12,246	$37,871	18%	10%	8%	120%	99%	4%	7%	$0	52%	149	394
	Stable Markets Scenario	$134	$133	$9,959	$23,990	14%	10%	4%	133%	112%	11%	16%	$590	2%	333	879

9.3.2 Affordability

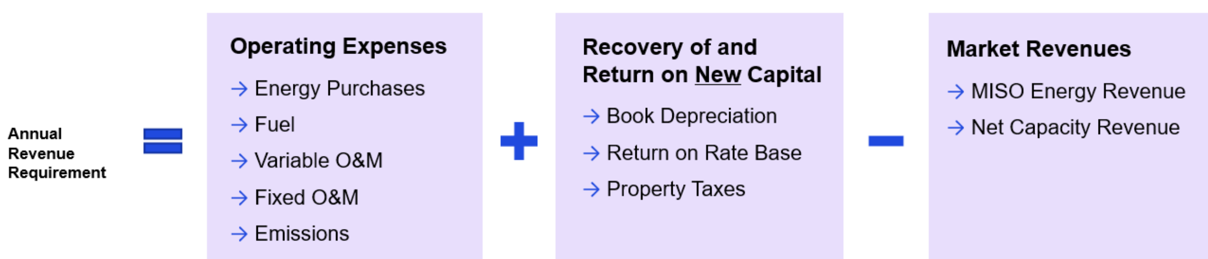
170 IAC 4-7-6(C)(4)(D)-(E)

IRP modeling is conducted to meet electricity demand in the most cost-effective manner, subject to a variety of constraints including but not limited to environmental programs, market access, reliability requirements, and more. Since IRPs look to minimize costs while maximizing system benefits, IRPs provide insights on how different resource mixes could influence cost pressures for customers.

However, IRPs do not provide commentary on rates for individual customer classes. Rates are covered through a separate regulatory process. Rate cases involve cost of service studies, which help allocate system costs across different customer groups. This type of study is not a part of the IRP.

A common metric used in IRP analysis is the present value revenue requirement (PVRR). The annual equation for PVRR is given in Figure 9-84. PVRR represents operating expenses plus recovery of and return on new capital, minus market revenues. It does not include any sunk or common costs. Annual PVRRs are discounted over time to provide a net present value requirement, which allows portfolios to be compared. The greater the PVRR, the more investment is required by a portfolio, and therefore the higher cost pressures that could be exerted on the utility.

Figure 9-84: PVRR Definition



The 2022 IRP used the 20-year PVRR to measure affordability. The 2025 IRP included a 10-year and 25-year PVRR metric instead. In the 2025 IRP, the 10-year PVRR metric reflected investment needed in the short-to-mid-term, and the 25-year metric covered the entirety of the study. This better facilitated comparison of investment required over time.

The 2025 IRP added two additional metrics: 10-Year Levelized Supply Cost (2026$/MWh, 2025-2035) and 25-Year Levelized Supply Cost (2026$/MWh, 2025-2035). This is because of the limitations of the PVRR metric. The larger the data center load, the more investment that will be required on the system, so the higher the PVRR. This is important to note, and the PVRR metric demonstrates this dynamic. However, PVRR does not reflect the fact that the additional costs to serve data center loads will be spread over the additional sales. As a result, to compare data center loads, AES Indiana created these additional metrics for levelized supply costs. This took the PVRR, plus sunk costs for existing resources (depreciation/decommissioning costs, amortization, and return on existing assets), and divided this by total retail sales. The costs for existing resources were added to show how data center load would influence the system in its entirety, and not just the incremental investment. The levelized supply costs allow for the cost pressures of different loads to be compared.

A matrix that provides PVRR and supply costs for the sixteen portfolios is shown in Figure 9-85 and Figure 9-86 below.[62]

Figure 9-85: 25-Year Incremental PVRR (2026$MM, 2026-2050)

No Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$10,092	$13,067	$14,941	$8,043
Challenged Gas	$10,161	$13,091	$14,944	$8,102
High Regulatory	$15,455	$17,378	$14,707	$12,595
Stable Markets	$10,070	$13,144	$14,763	$7,429

Low Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$12,654	$16,431	$18,616	$9,895
Challenged Gas	$13,047	$16,509	$19,348	$10,349
High Regulatory	$19,827	$22,064	$18,377	$15,588
Stable Markets	$12,699	$16,622	$18,573	$9,273

Mid Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$18,187	$23,307	$26,744	$14,152
Challenged Gas	$18,499	$23,190	$27,303	$14,619
High Regulatory	$30,040	$32,546	$26,086	$22,878
Stable Markets	$18,266	$23,996	$26,295	$13,215

High Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$23,754	$29,824	$35,286	$18,596
Challenged Gas	$24,032	$29,846	$35,703	$18,969
High Regulatory	$37,871	$41,290	$33,852	$27,764
Stable Markets	$23,990	$30,824	$34,442	$17,532

[62] The columns of the figures compare the results of across the alternative future scenarios.

Figure 9-86: 10-Year Levelized Supply Cost ($2026/MWh, 2026-2035)

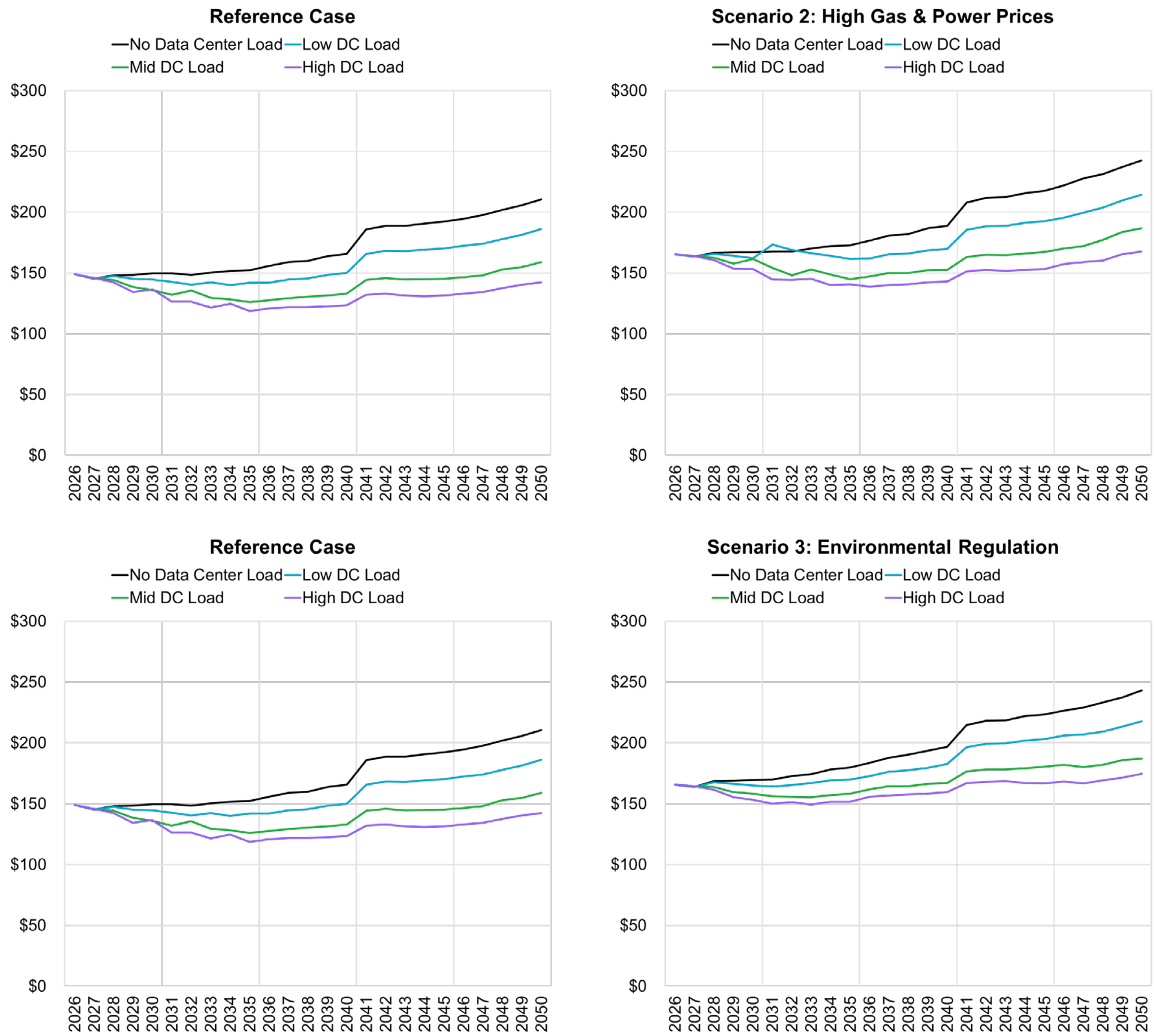
No Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$149.08	$167.53	$170.47	$154.83
Challenged Gas	$149.33	$167.53	$170.52	$155.11
High Regulatory	$156.06	$173.25	$170.37	$161.05
Stable Markets	$149.08	$167.65	$170.38	$153.90

Low Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$144.44	$163.22	$166.13	$147.40
Challenged Gas	$147.68	$165.51	$170.29	$150.47
High Regulatory	$152.76	$170.08	$166.24	$154.39
Stable Markets	$144.72	$163.66	$167.10	$146.34

Mid Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$137.86	$156.59	$160.82	$137.29
Challenged Gas	$139.47	$157.18	$163.65	$138.85
High Regulatory	$150.71	$167.19	$160.12	$147.11
Stable Markets	$137.89	$156.93	$160.61	$135.26

High Data Center	Scenarios			
	Reference Case	Gas Infrastructure Challenges	High Regulatory: Environmental	Stable Markets Scenario
Reference Case	$134.37	$152.51	$159.44	$131.93
Challenged Gas	$135.03	$152.83	$160.43	$132.42
High Regulatory	$144.62	$161.90	$156.44	$138.89
Stable Markets	$134.19	$154.02	$157.45	$129.46

Figure 9-87: Supply Costs – Annual Revenue Requirement Divided by Sales (Nominal $/MWh)



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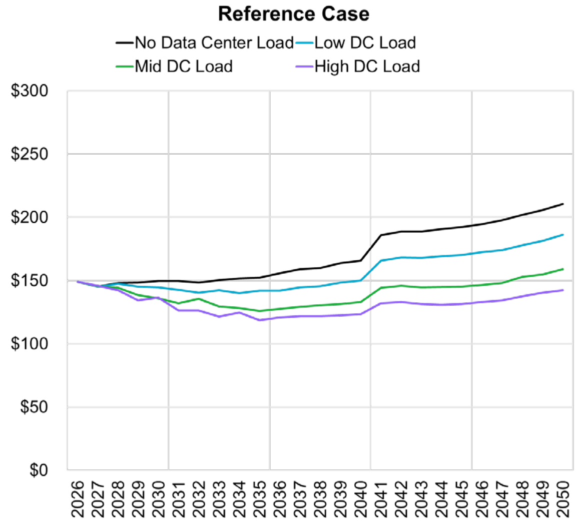


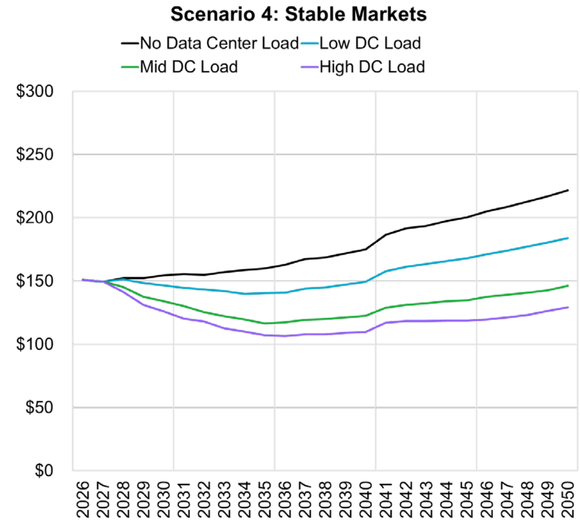
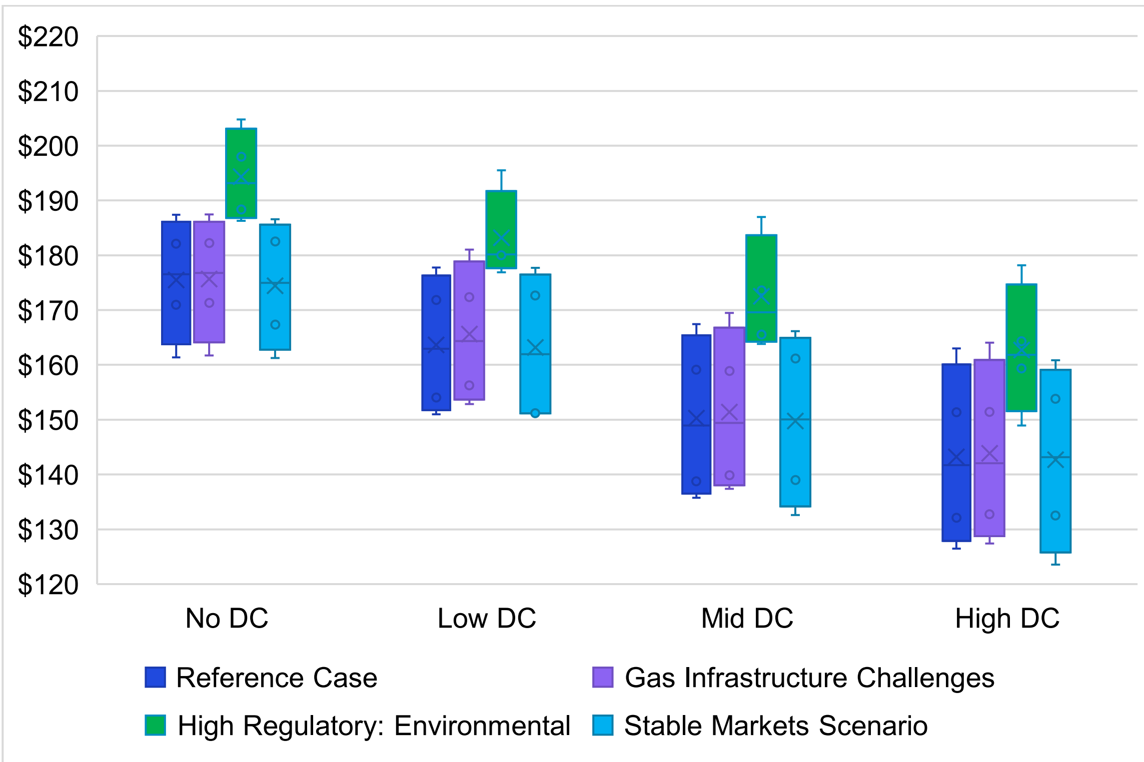


Figure 9-88: 25-Year Levelized Supply Cost (2026$/MWh, 2025-2050)



The 2025 IRP was not designed to analyze rates for distinct customer classes; such analyses are appropriately addressed within the scope of a rate proceeding. AES Indiana understands that customers generally want to know what data centers can do to rates. In addition to using the PVRR and system cost metrics to comment on cost pressures, AES Indiana created a marginal cost view. This view shows the incremental costs, in $/MWh, that data centers would incur on the system. If data centers covered these incremental costs, then there would be no increased rate pressures on other rate classes. In other words, this represents a floor rate that data center customers could pay to insulate other customers from higher costs.

Figure 9-89 contains a view of levelized system cost rates for all 16 optimized portfolios. In every scenario, the incremental system cost of adding new large loads is lower than the all-in cost of the no data center case.

Figure 9-89: Total and Incremental System Rates by Load Case and Scenario (Levelized $/MWh)

Scenario	Load Case Portfolio	Variable	10-Year	25-Year
Reference Case	No Data Center	Total System Rate	$150	$163
	Low Data Center	Incremental Cost Rate	$92	$90
	Mid Data Center	Incremental Cost Rate	$93	$91
	High Data Center	Incremental Cost Rate	$96	$92
Challenged Gas	No Data Center	Total System Rate	$170	$185
	Low Data Center	Incremental Cost Rate	$131	$119
	Mid Data Center	Incremental Cost Rate	$116	$113
	High Data Center	Incremental Cost Rate	$114	$112
High Regulatory	No Data Center	Total System Rate	$174	$190
	Low Data Center	Incremental Cost Rate	$118	$120
	Mid Data Center	Incremental Cost Rate	$120	$122
	High Data Center	Incremental Cost Rate	$121	$123
Stable Market	No Data Center	Total System Rate	$156	$170
	Low Data Center	Incremental Cost Rate	$71	$67
	Mid Data Center	Incremental Cost Rate	$67	$65
	High Data Center	Incremental Cost Rate	$69	$68

Figure 9-90 through Figure 9-101 contain annual incremental costs compared to the No Data Center case for all scenarios.

Figure 9-90: Annual Revenue Requirement – Reference – Low Data Center ($/MWh)

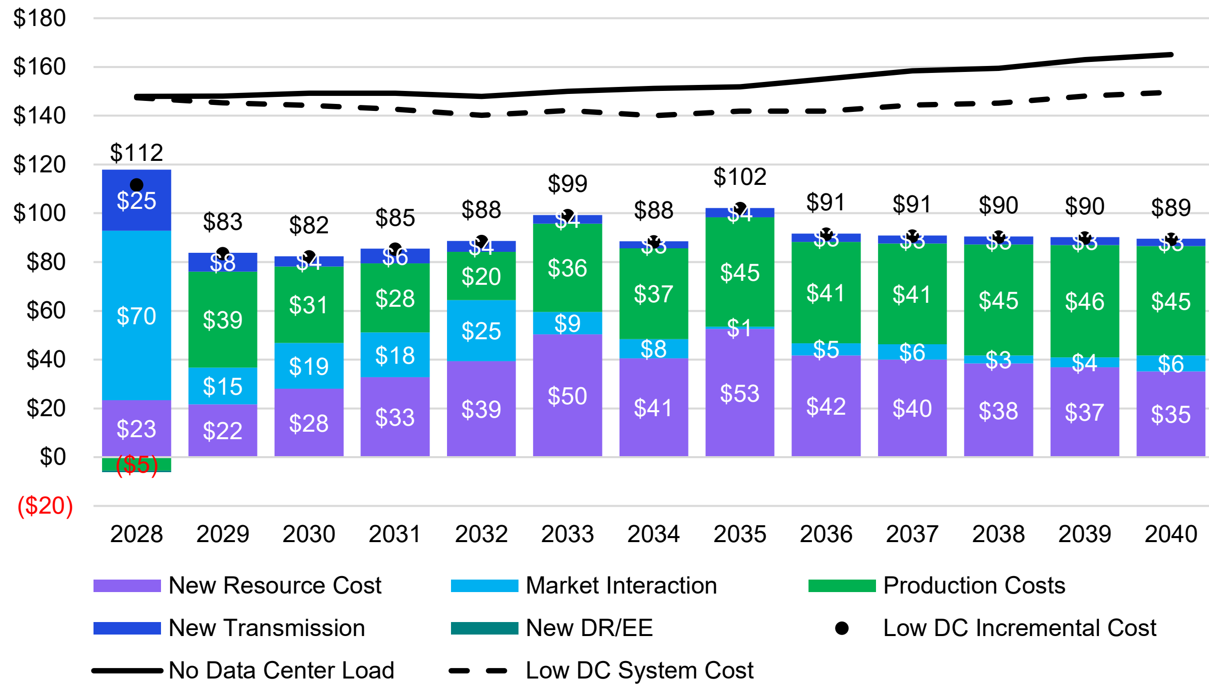


Figure 9-91: Annual Revenue Requirement – Reference – Mid Data Center ($/MWh)

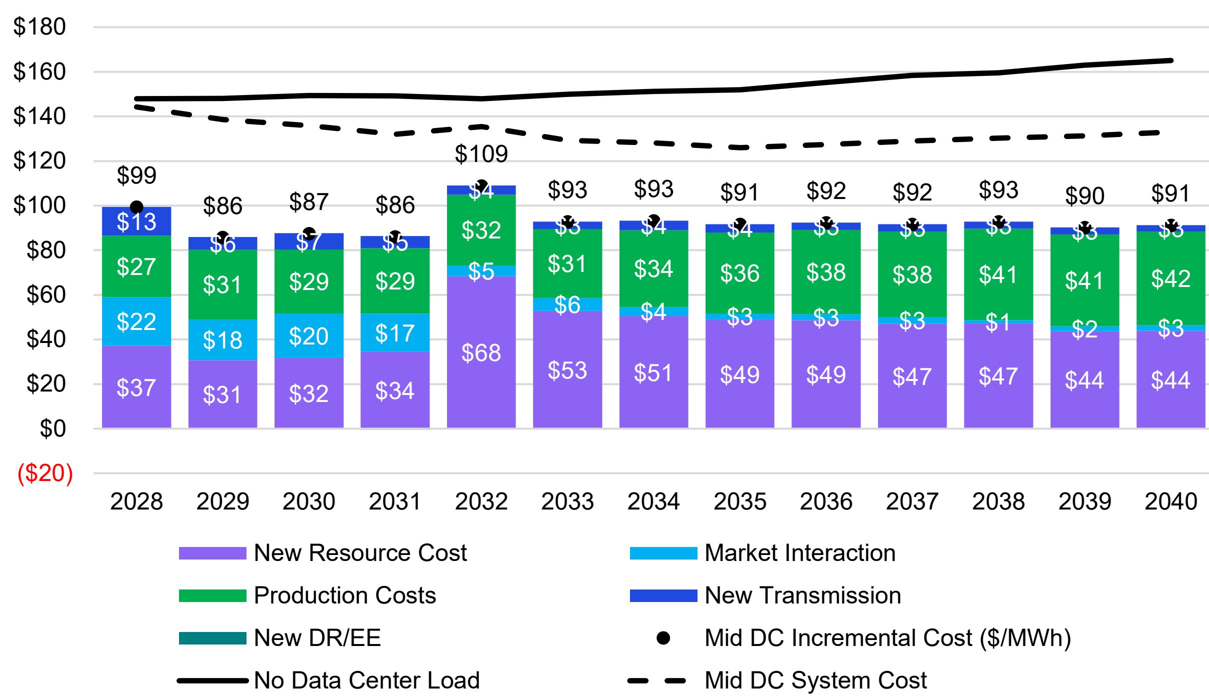


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Figure 9-92: Annual Revenue Requirement – Reference – High Data Center ($/MWh)

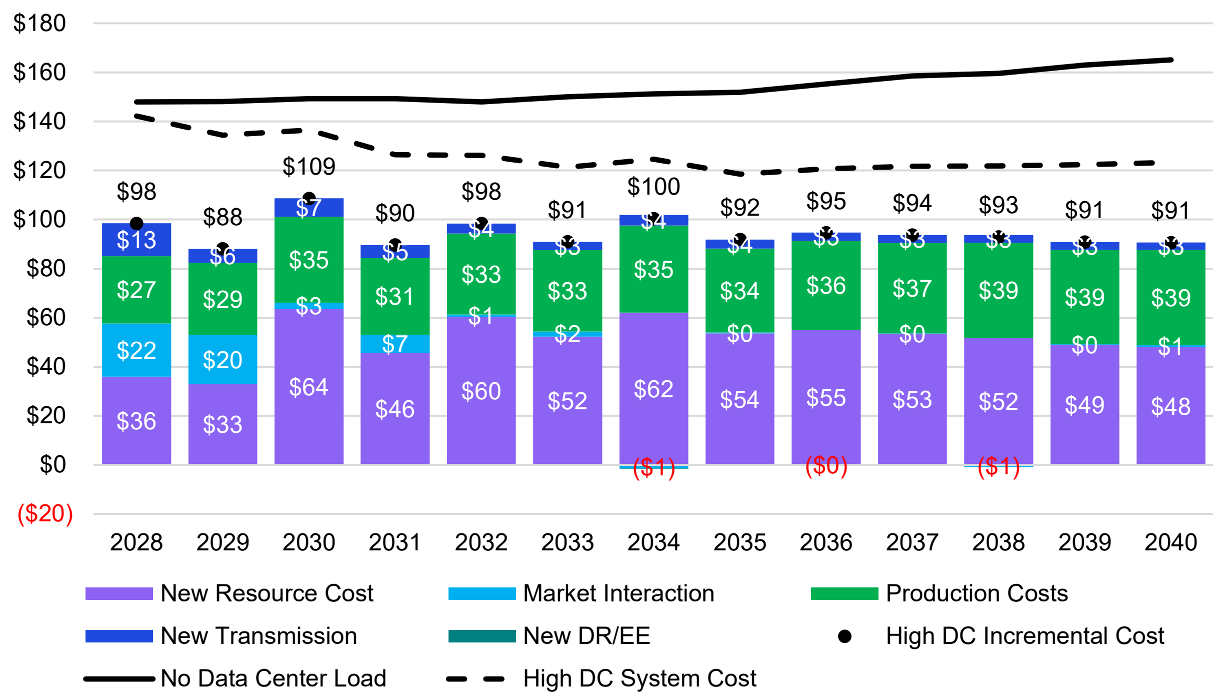


Figure 9-93: Annual Revenue Requirement – Challenged Gas – Low Data Center ($/MWh)

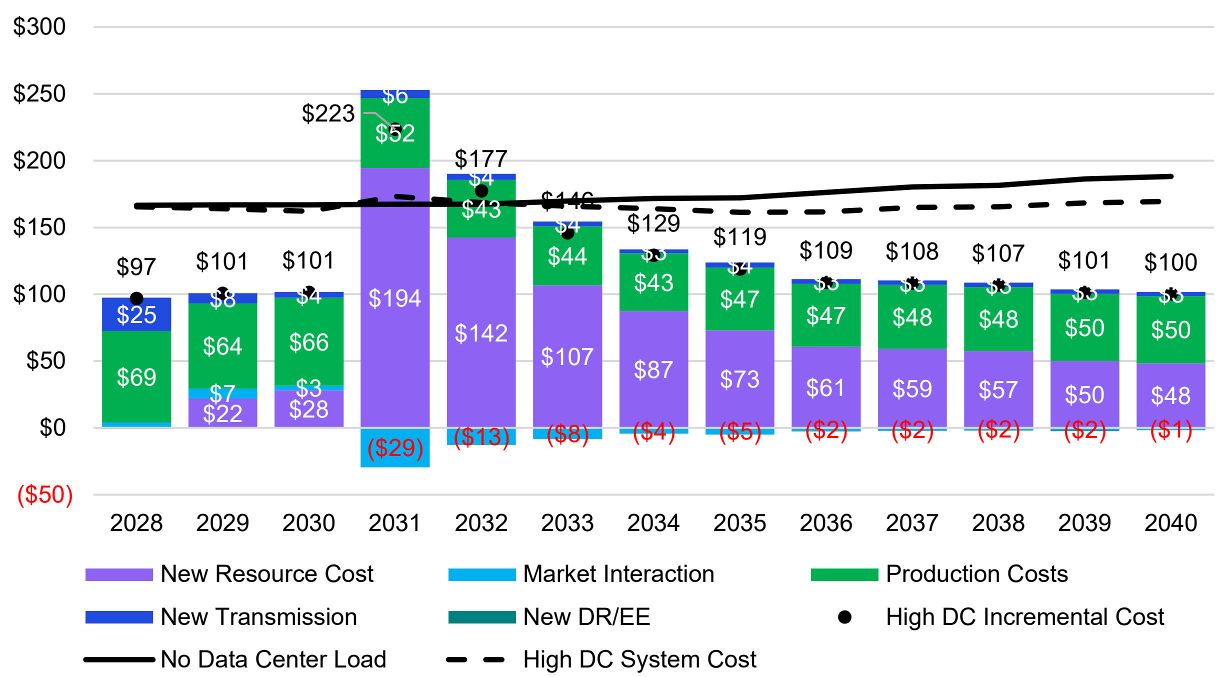


Figure 9-94: Annual Revenue Requirement – Challenged Gas – Mid Data Center ($/MWh)

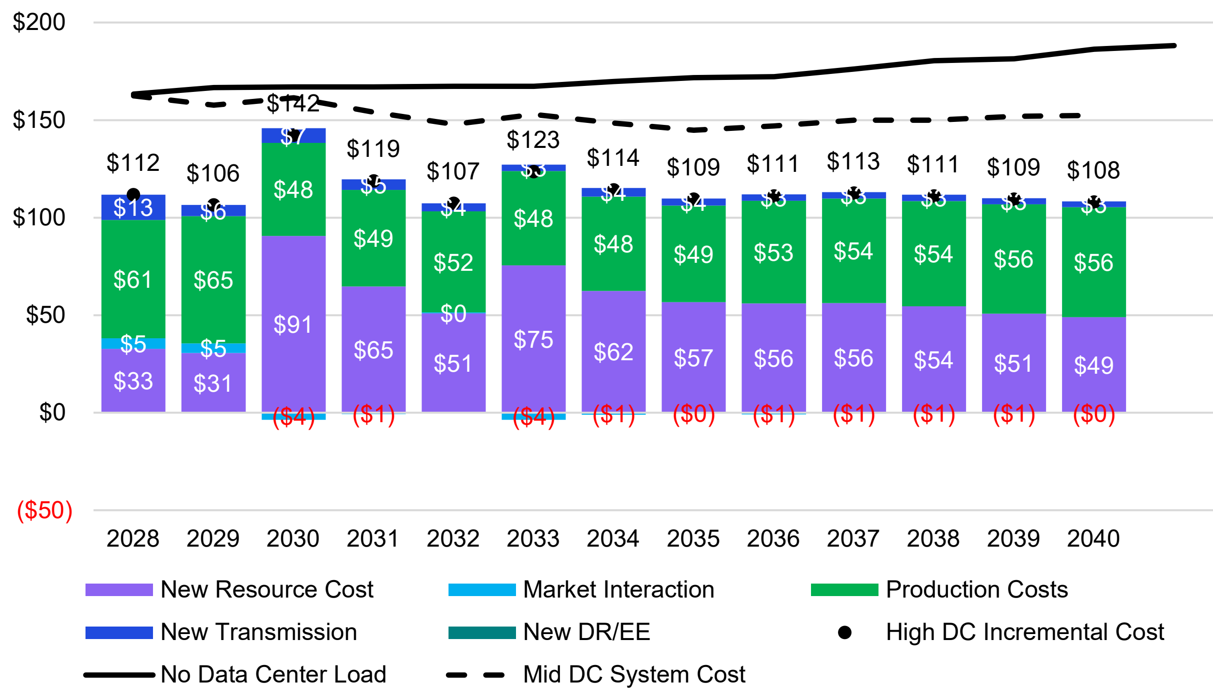


Figure 9-95: Annual Revenue Requirement – Challenged Gas – High Data Center ($/MWh)

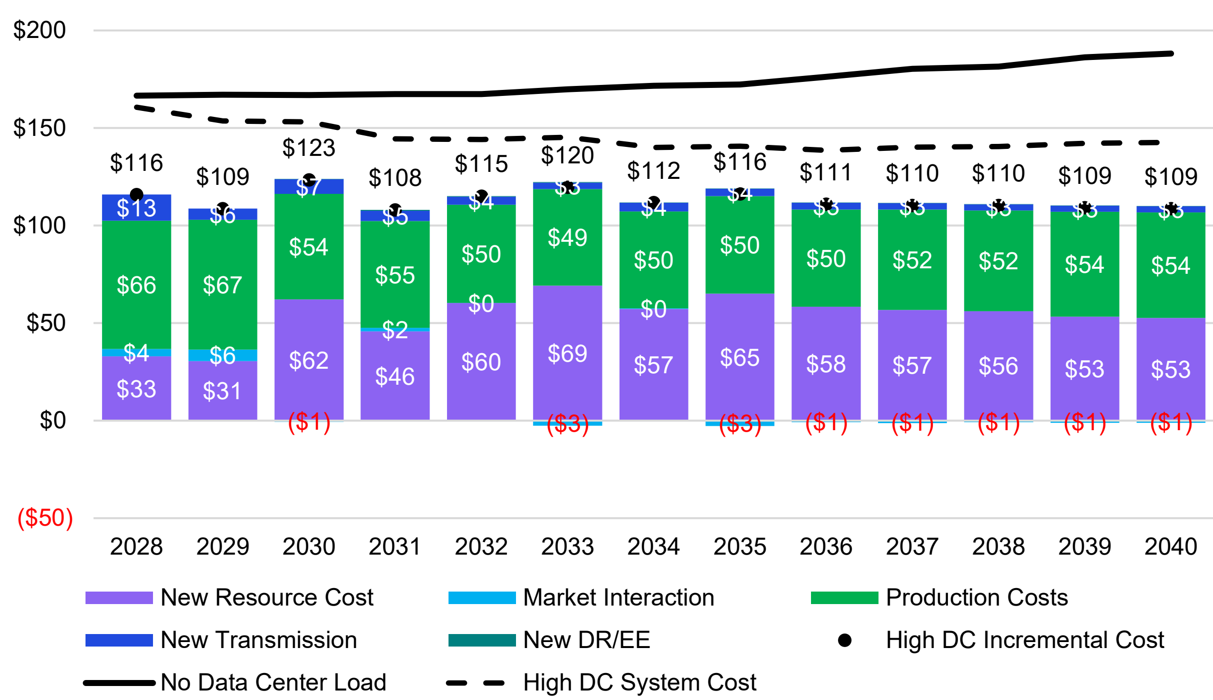


Figure 9-96: Annual Revenue Requirement – High Regulatory – Low Data Center ($/MWh)

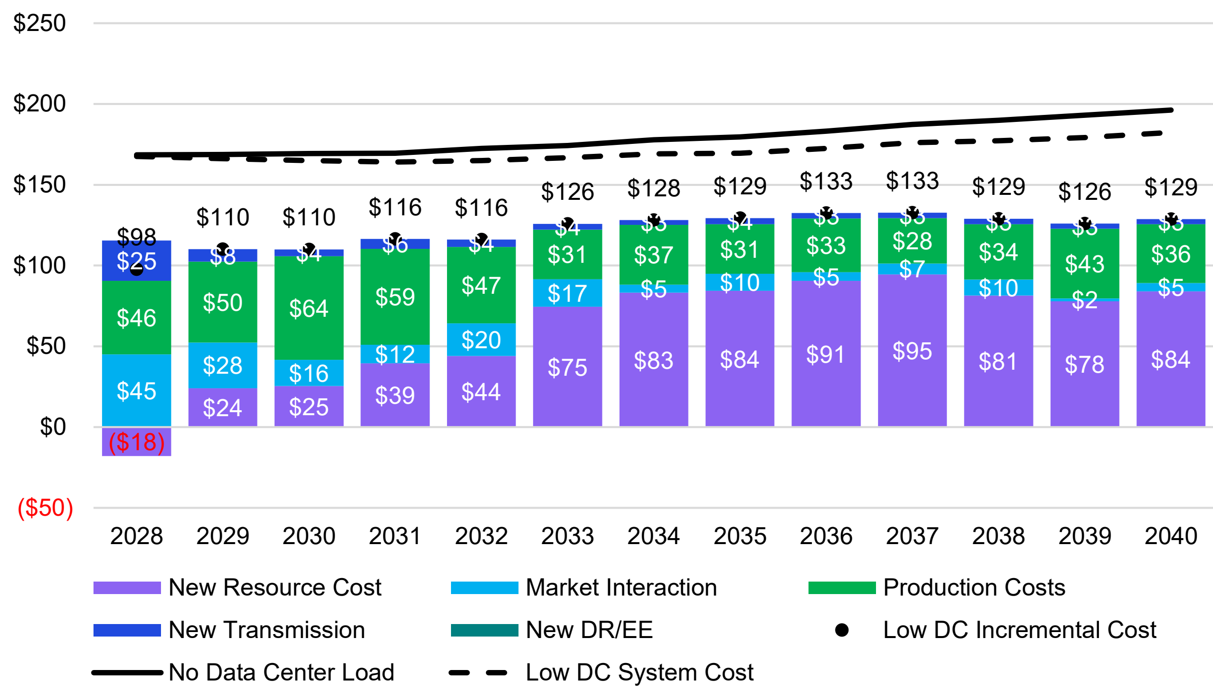


Figure 9-97: Annual Revenue Requirement – High Regulatory – Mid Data Center ($/MWh)

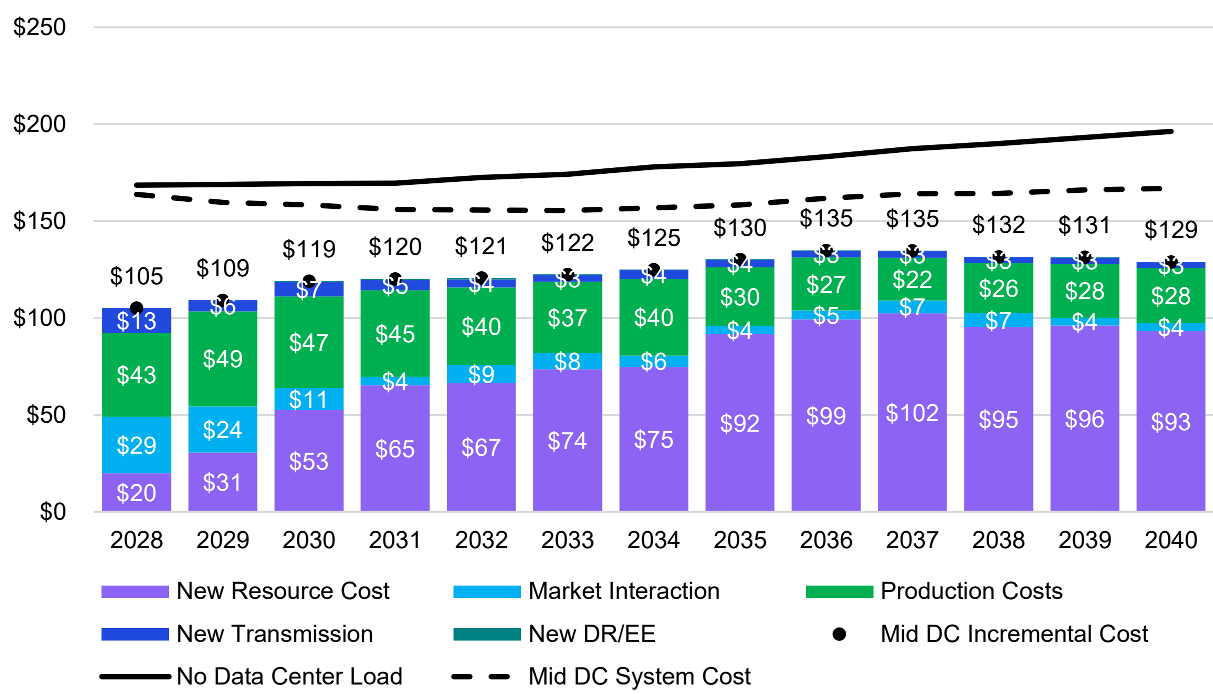


Figure 9-98: Annual Revenue Requirement – High Regulatory – High Data Center ($/MWh)

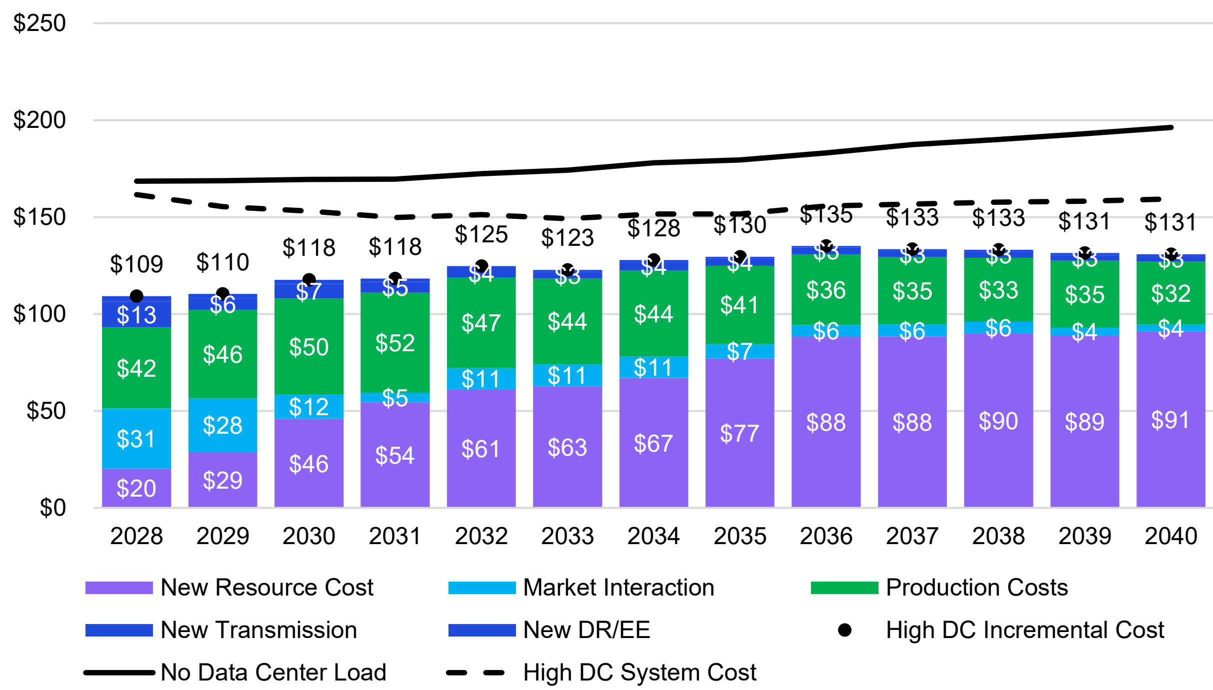


Figure 9-99: Annual Revenue Requirement – Stable Market – Low Data Center ($/MWh)

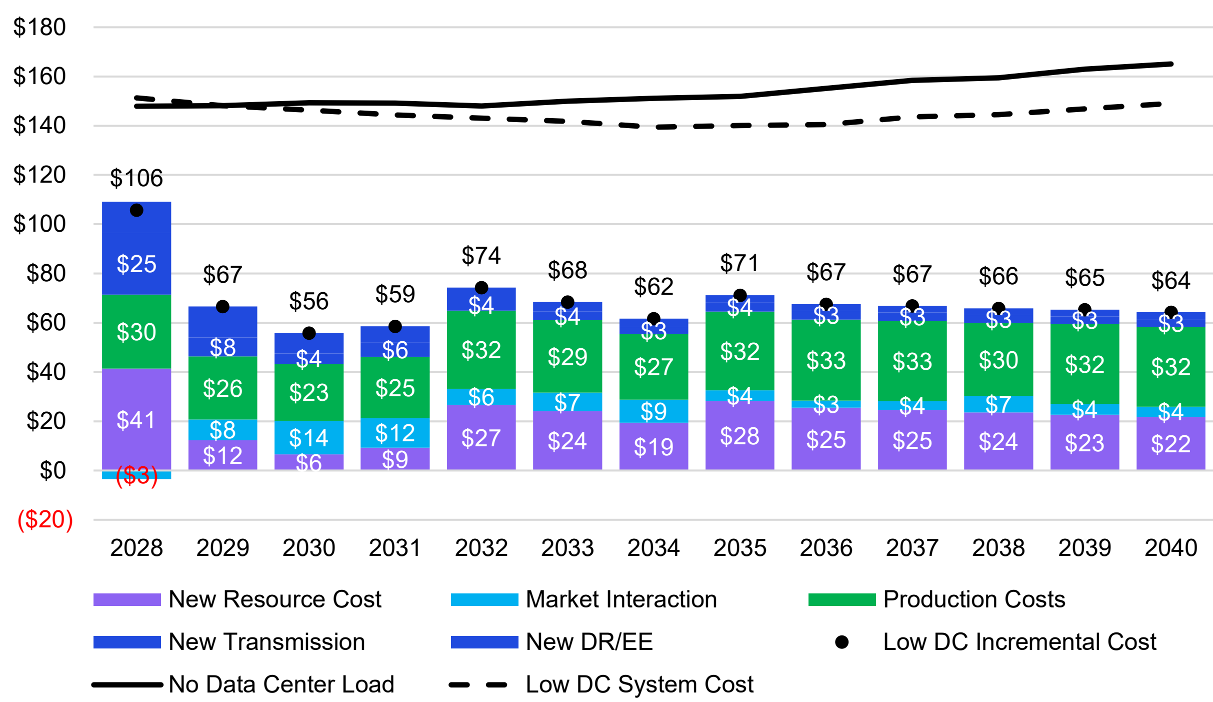


Figure 9-100: Annual Revenue Requirement – Stable Market – Mid Data Center ($/MWh)

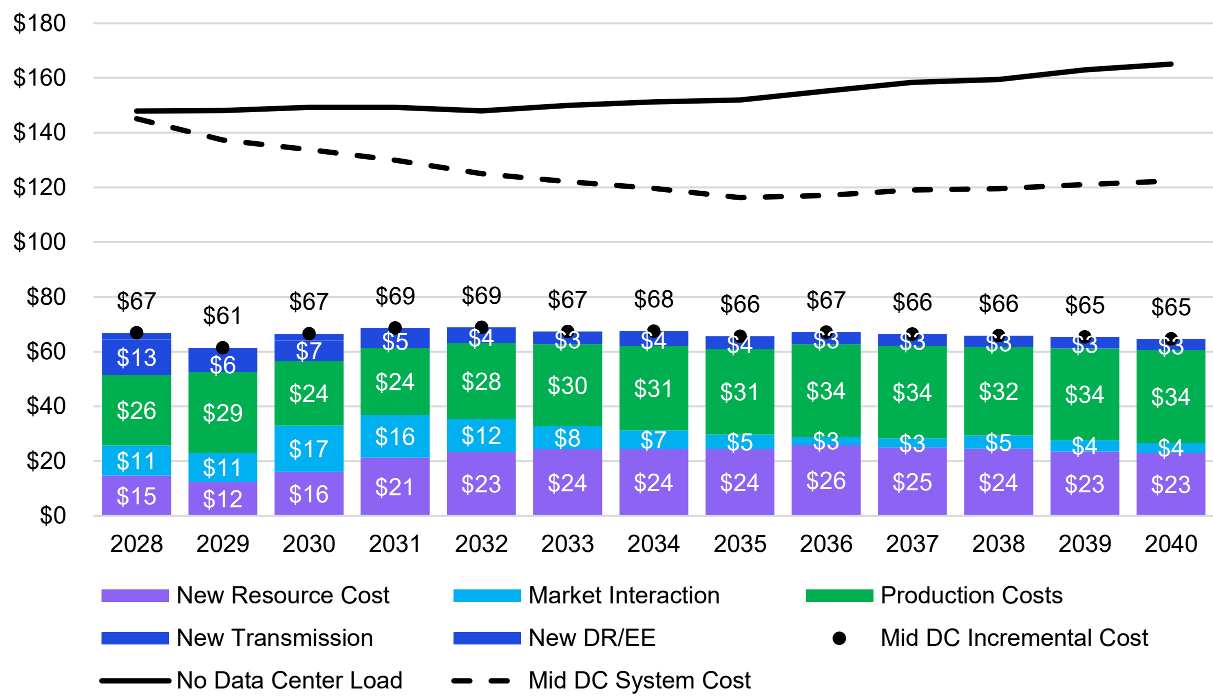
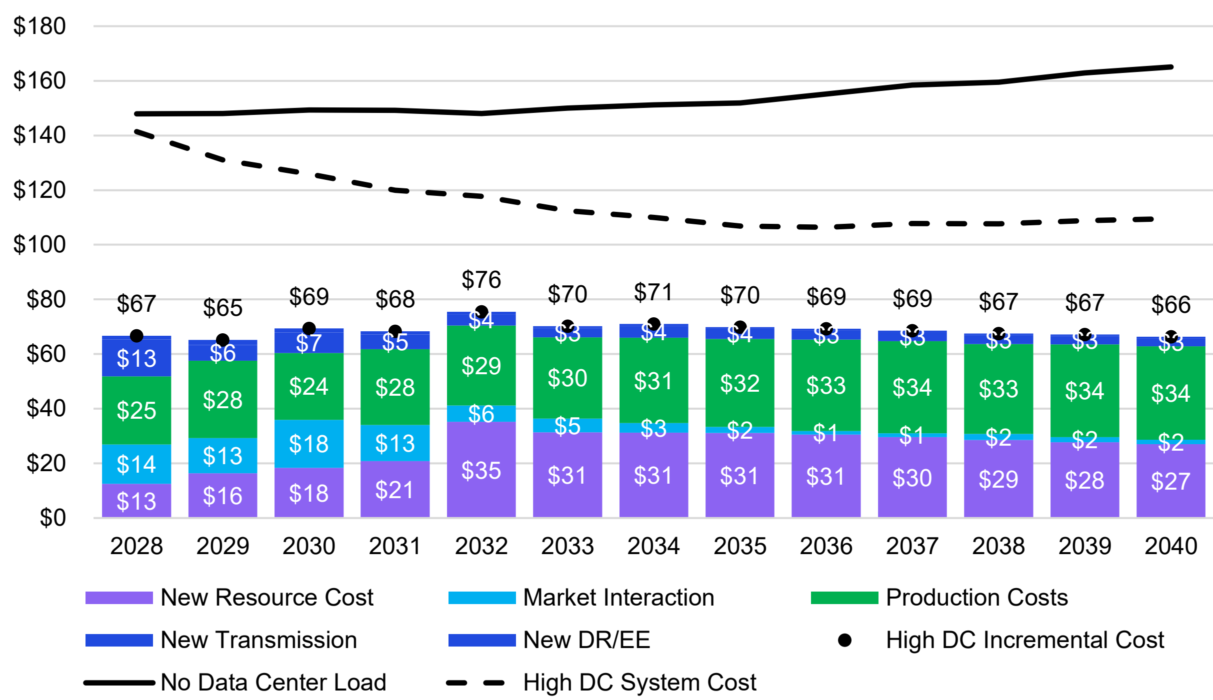


Figure 9-101: Annual Revenue Requirement – Stable Market – High Data Center ($/MWh)



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9.3.3 Reliability, Resiliency, and Stability

170 IAC 4-7-8(c)(2) and 170 IAC 4-7-8(c)(4)(B)

Reliability, resiliency, and stability were incorporated into the designs of each portfolio. Resource mixes were created to adhere to MISO requirements under the Direct Loss of Load (DLOL) approach for all years. See Figure 9-102 for the seasonal reserve margins. Total reliability requirements are equivalent to peak plus the reserve margin for each season. Resources were given accreditation towards requirements for each season based on their resource type and/or individual performance. Capacity markets are further discussed in Section 2.

Figure 9-102: MISO Seasonal Reserve Margin (%)

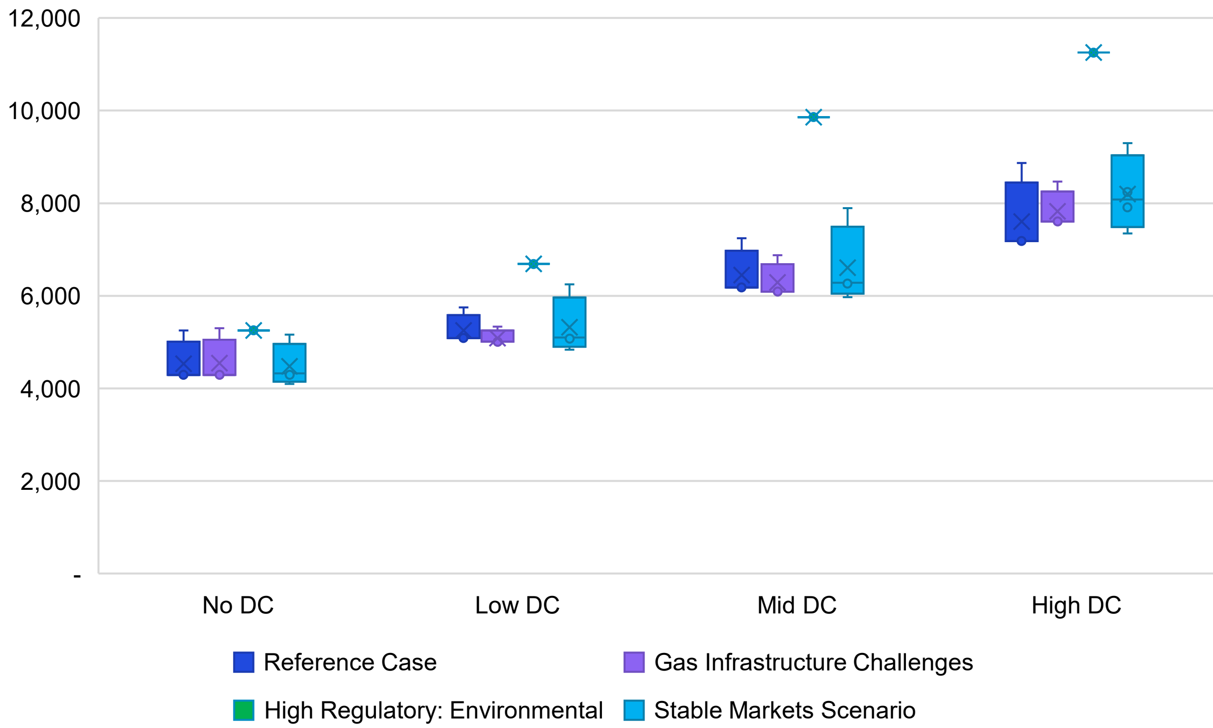
Season	MISO Reserve Margin
Summer	2.9%
Fall	4.1%
Winter	6.2%
Spring	2.1%

By design, the portfolios meet MISO's capacity requirements. However, AES Indiana implemented an additional reliability measure. During the capacity optimization (when new resources were selected), capacity purchases and sales were limited to 50 MW per season. This prevents the model from over- or under-building in comparison to the load.

Different portfolios solved to varying levels of load. For the portfolios that were created for low loads (like the Stable Markets Portfolio) that were asked to perform under high native load scenarios (like the High Regulatory: Environmental), AES Indiana performed an interim step that allowed those portfolios to install additional capacity. See Section 8.2.3 for further details. If AES Indiana experiences a native load shift due to fundamentally different market conditions, this modeling approach shows how AES Indiana would adapt to procure additional resources.

The greater the data center load, the greater the installed capacity. See Figure 9-103. The High Regulatory markets install more capacity compared to the other portfolios as the accreditation for solar, wind, and storage declines over time.

Figure 9-103: Installed Capacity (MW) in 2035 Across Portfolios



Overall, portfolios across scenarios have 111% to 135% of peak 2035 load in dispatchable capacity, and 90% to 116% of peak 2035 load in dispatchable firm capacity. See Figure 9-104.

Figure 9-104: Dispatchable Capacity Metrics for Candidate Portfolios

Load	Portfolio	Dispatchable Capacity Divided by Peak Load (2035)	Dispatchable FIRM Capacity Divided by Peak Load (2035)	Storage FIRM Capacity (2035)	Natural Gas FIRM Capacity (2035)	Storage Capacity (2035)	Natural Gas Capacity (2035)	Peak Load (2035)	Total Installed Capacity (MW) in 2035
No DC	Reference Case	111%	90%	366	2,283	430	2,810	2,928	4,292
	Gas Infrastructure Challenges	118%	96%	366	2,283	430	2,810	2,751	4,292
	High Regulatory: Environmental	115%	94%	383	2,283	450	2,810	2,832	5,253
	Stable Markets Scenario	121%	99%	281	2,283	330	2,810	2,593	4,097
Low DC	Reference Case	121%	99%	638	2,691	750	3,290	3,351	5,088
	Gas Infrastructure Challenges	124%	104%	417	2,884	490	3,450	3,175	5,007
	High Regulatory: Environmental	121%	100%	944	2,283	1,110	2,810	3,229	6,688
	Stable Markets Scenario	124%	102%	375	2,691	450	3,290	3,017	4,838
Mid DC	Reference Case	122%	102%	1,012	3,292	1,190	3,930	4,209	6,179
	Gas Infrastructure Challenges	122%	104%	604	3,578	710	4,198	4,032	6,088
	High Regulatory: Environmental	122%	101%	1,825	2,283	2,170	2,810	4,074	9,858
	Stable Markets Scenario	124%	102%	861	3,099	1,050	3,770	3,874	5,972
High DC	Reference Case	118%	102%	825	4,337	970	5,024	5,062	7,181
	Gas Infrastructure Challenges	129%	113%	808	4,689	950	5,370	4,886	7,605
	High Regulatory: Environmental	124%	101%	2,305	2,691	2,810	3,290	4,927	11,253
	Stable Markets Scenario	131%	110%	1,095	4,108	1,290	4,890	4,728	7,347

AES Indiana also accounted for reliability, resiliency, and stability in its modeling of energy market access. Energy purchases and sales were constrained to 20% each on an annual basis, anchored to the No Data Center: Reference Case. This also prevents under- or over-building of resources in comparison to AES Indiana's native load. Furthermore, it ensures that large load integration will not increase AES Indiana's overall exposure to energy market access. See Figure 9-105 and Figure 9-106 for depictions of purchases and sales. In the graphs, different data center loads are depicted horizontally. The vertical values for each portfolio represent purchases or sales for each resource mix across the four scenarios.

Purchases generally range between 10% and 20% of the load; in the modeling, they were constrained to 20%, anchored to 20% of the No Data Center load. As shown in Figure 9-105, the Gas Infrastructure Challenges portfolio has the greatest spread in purchases as a percentage of retail load. Greater reliance on combined cycle sooner leads to a greater dependence on gas prices, which vary across scenarios.

In Figure 9-106, sales range between 10 to 20% of the load; again, sales were constrained to 20% annually.

Figure 9-105: Average Ten-Year Purchases as a Percent (%) of Retail Load

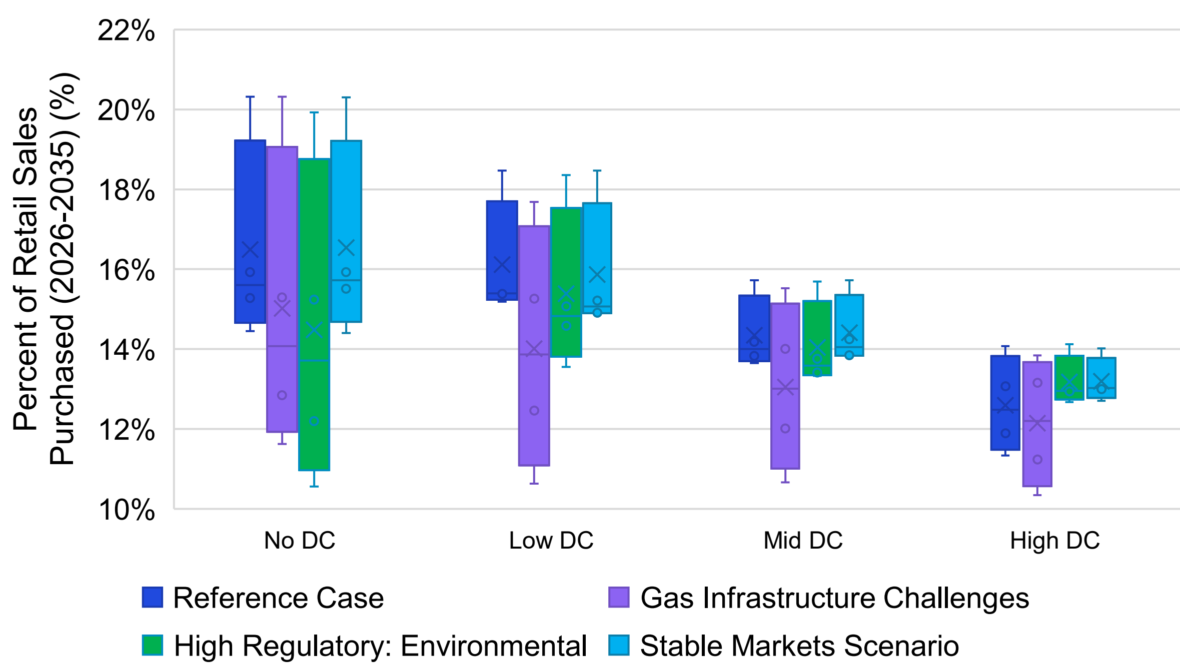
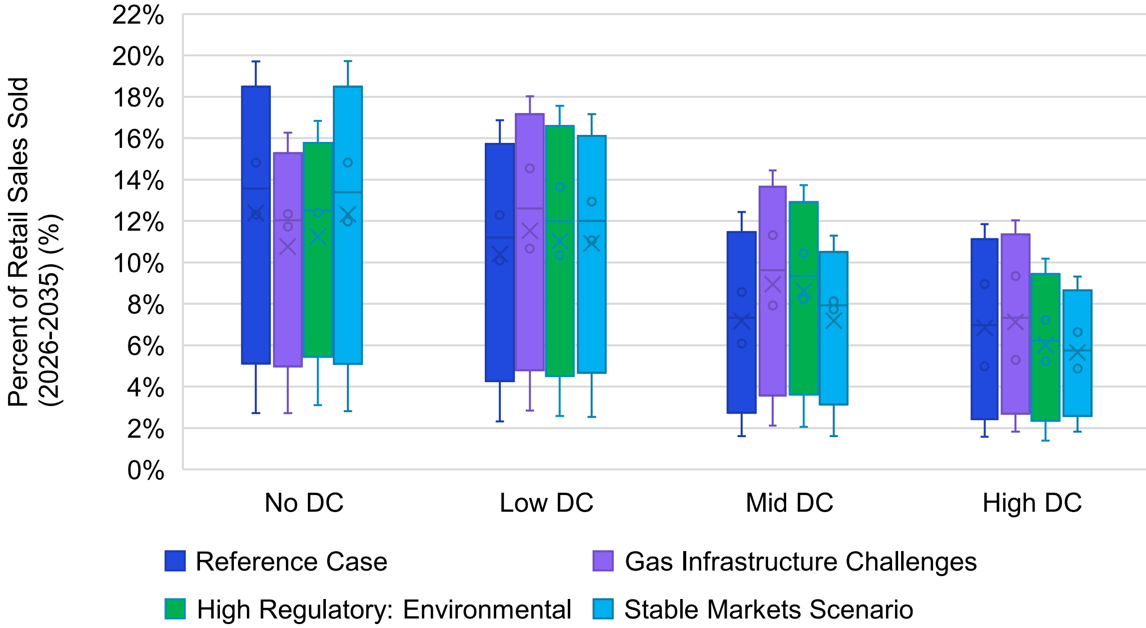


Figure 9-106: Average Ten-Year Sales as a Percent (%) of Retail Load



Quanta Technology Study

AES Indiana hired Quanta Technology to support additional reliability analysis. They were tasked with assessing and ranking the candidate IRP portfolios to ensure the sufficiency of Essential Reliability Services (ERS) and to quantify any required mitigations. Analysis focused on the following:

→ ERS
  - Import / Export analysis
  - Energy Adequacy
  - Frequency Response
    - Inertial
    - Primary response
    - System Stability
  - Short Circuit Strength

The following insights came from the ERS studies:

Import / Export Transmission Limit Findings

Between 2027 and 2035, the AES IPL transmission network is expected to undergo significant reinforcement, with the number of tie lines increasing from 18 to 39, substantially enhancing interconnection with neighboring systems. Application of the MISO contingency package allows accurate estimation of import capability under various operating conditions.

As a result, AES IPL's import limit increases from 578 MW in 2027 to 2,193 MW in 2030, and further to 2,503 MW by 2035, reflecting progressive transmission expansion and system strengthening.

Despite this improvement, export capability remains extremely limited due to rising internal demand, primarily driven by data center growth, including new non-AES Indiana loads. Even with 4,630 MW of dispatchable generation capacity, AES IPL operates close to its internal supply-demand balance, leaving little margin for exports.

This trend underscores the importance of managing local generation, load growth, and transmission constraints to maintain future reliability and operational flexibility.

Figure 9-107 contains results from the 100% import case.

Energy Adequacy Results

Energy Adequacy simulations demonstrate that, if AES IPL maintains full or partial import capability (100% or 50%), the system can reliably meet demand through 2035, even under 90/10 high load scenarios. However, when imports are restricted to 0% (i.e., islanded operation), the system becomes energy-inadequate, with neither energy adequacy nor Planning Reserve Margin (PRM) targets being met.

Key findings include:

- Under 0% import conditions, energy shortfalls occur in Portfolios 3, 4, 7, 8, 15, and 16, with Portfolio 8 (2035) being the most critical.
- Nearly all portfolios fail to meet PRM requirements for 2030 and 2035, with the most severe deficits in Portfolios 7 and 8.

These results highlight the vital role of regional interconnections in ensuring long-term system adequacy. To maintain reliability, AES IPL should:

- Preserve import flexibility by ensuring strong interconnection capability.
- Continue investment in transmission upgrades to support regional energy exchange.
- Coordinate with MISO and neighboring utilities to ensure system adequacy under both normal and constrained operating conditions.

Frequency Response Analysis

Frequency response simulations were conducted to evaluate AES IPL's inertial and primary frequency response following the sudden loss of a 525 MW generating unit (Petersburg 3) under both interconnected and islanded conditions.

Under interconnected operation, all portfolios maintained acceptable frequency stability through 2040, supported by the repowering of retired coal plants with new synchronous generation, which enhances system inertia and frequency resilience.

Under islanded emergency conditions, however, several portfolios exhibited frequency nadir drops exceeding 0.5 Hz between 2027 and 2028, surpassing Underfrequency Load Shedding (UFLS) thresholds and placing parts of the load at risk of disconnection.

A similar pattern was observed in Portfolios 4, 8, and 16, where frequency recovery became adequate—maintaining a nadir above 59.5 Hz—only after 2029 for Portfolios 4 and 16 and after 2030 for Portfolio 8.

Additional resource requirements were identified to mitigate Primary Frequency Response (PFR) deficits:

- Greatest needs occur between 2027 and 2032, with the worst-case condition in Portfolio 8.
- Secondary Frequency Regulation requirements are highest under the High Regulatory: Environmental portfolio, reflecting increased system stress under stricter operational conditions.

These results emphasize the need for fast frequency response resources, such as battery storage and synchronous support, to strengthen system resilience during islanded or low-inertia operation.

Figure 9-109, Figure 9-110, and Figure 9-111 contain results from the frequency study.

Short Circuit Strength Analysis Conclusions

Two system configurations were evaluated for short circuit strength in the High Regulatory: Environmental scenario for the year 2035: the interconnected system and the Islanded system.

In the interconnected case, all four portfolios (P5 to P8) achieved 100% integration of inverter-based resources (IBRs), demonstrating that external grid support significantly enhances short circuit strength and ensures compliance with ESCR thresholds.

In contrast, the islanded system scenario revealed limitations in portfolios P7 and P8, which had higher renewable penetration. Their pass rates dropped to 70.2% and 67.6%, respectively, due to reduced short circuit contributions from IBRs.

Portfolios P5 and P6 maintained full integration even without external support, indicating their configurations are within acceptable ESCR limits.

These findings underscore the importance of grid interconnections and the need for mitigation strategies—such as synchronous condensers or grid-forming inverters—when planning high-renewable portfolios in isolated grid conditions.

  - .

Figure 9-107: Quanta Study – 100% Imports

		Import 100% (2027)					Import 100% (2030)					Import 100% (2035)				
	Portfolio ↓	Short (MW)	Short (Average MW, Summer)	Short (Average MW, Winter)	Short (Max MW, Summer)	Short (Max MW, Winter)	Short (MW)	Short (Average MW, Summer)	Short (Average MW, Winter)	Short (Max MW, Summer)	Short (Max MW, Winter)	Short (MW)	Short (Average MW, Summer)	Short (Average MW, Winter)	Short (Max MW, Summer)	Short (Max MW, Winter)
Reference Case	No Data Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Low DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mid DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	High DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Challenged Gas	No Data Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Low DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mid DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	High DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Regulatory	No Data Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Low DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mid DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	High DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stable Markets	No Data Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Low DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Mid DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	High DC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9-108: Quanta Study – No Import Lost Load

	Import 0% (2027)						Import 0% (2030)						Import 0% (2035)					
	LOLE	EUE	LOLP	LOLH	LOLH (Summer)	LOLH (Winter)	LOLE	EUE	LOLP	LOLH	LOLH (Summer)	LOLH (Winter)	LOLE	EUE	LOLP	LOLH	LOLH (Summer)	LOLH (Winter)
Reference Case - No Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Reference Case - Low Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Reference Case - Mid Data Center	0	0	0.0%	0	0	0	4	0	0.1%	7	0	0	12	1	0.2%	14	8	0
Reference Case - High Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	10	1	0.1%	13	4	0
Gas Infrastructure Challenges - No Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Gas Infrastructure Challenges - Low Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Gas Infrastructure Challenges - Mid Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Gas Infrastructure Challenges - High Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
High Environmental - No Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
High Environmental - Low Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	1	0	0.0%	1	0	0
High Environmental - Mid Data Center	0	0	0.0%	0	0	0	2	0	0.0%	4	0	0	1996	999	32.6%	2,857	914	722
High Environmental - High Data Center	0	0	0.0%	0	0	0	493	125	9.5%	835	336	157	3322	4770	70.9%	6,213	1,819	1,318
Stable Markets - No Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Stable Markets - Low Data Center	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%	0	0	0
Stable Markets - Mid Data Center	0	0	0.0%	0	0	0	4	0	0.1%	7	0	0	290	61	5.7%	503	147	80
Stable Markets - High Data Center	0	0	0.0%	0	0	0	942	266	18.6%	1630	579	410	357	89	6.8%	594	173	1

Figure 9-109: Quanta Study - Frequency Response

Portfolio ↓	Frequency Response - MISO Connected Margin between Installed Generation and Required Capacity to Limit Frequency Drop below critical limits. 2027	2030	2035	Frequency Response - Islanded Emergency Condition. Margin between Installed Generation and Required Capacity to Limit Frequency Drop below critical limits. 2027	2030	2035
Reference Case - No Data Center	1,001	1,002	1,068	626	755	1,266
Reference Case - Low Data Center	915	1,054	1,337	143	1,523	1,786
Reference Case - Mid Data Center	1,172	1,305	1,751	626	1,037	619
Reference Case - High Data Center	756	1,439	2,950	(927)	1,387	1,471
Gas Infrastructure Challenges - No Data Center	1,001	2	1,068	626	757	1,266
Gas Infrastructure Challenges - Low Data Center	1,072	1,210	1,524	626	1,420	1,686
Gas Infrastructure Challenges - Mid Data Center	667	1,097	1,974	(930)	1,655	1,482
Gas Infrastructure Challenges - High Data Center	756	1,439	2,936	(927)	1,384	1,891
High Environmental - No Data Center	1,001	1,002	1,068	876	1,255	1,391
High Environmental - Low Data Center	1,072	1,210	1,305	876	1,478	1,790
High Environmental - Mid Data Center	841	975	975	(144)	1,201	1,925
High Environmental - High Data Center	60	105	525	(2,949)	707	1,604
Stable Markets - No Data Center	1,001	1,002	1,068	626	632	641
Stable Markets - Low Data Center	1,072	1,210	1,537	626	901	1,496
Stable Markets - Mid Data Center	1,172	1,305	2,205	626	1,229	1,316
Stable Markets - High Data Center	524	569	2,551	(1,643)	753	1,350

Figure 9-110: Quanta Study - Primary Frequency Response

Portfolio ↓	Resource Deficit for Primary Frequency Response (Additional Generation, Islanded) 2027	2028	2029 - 2040
Reference Case - No Data Center	0	0	0
Reference Case - Low Data Center	0	0	0
Reference Case - Mid Data Center	0	0	0
Reference Case - High Data Center	927	0	0
Gas Infrastructure Challenges - No Data Center	0	0	0
Gas Infrastructure Challenges - Low Data Center	0	0	0
Gas Infrastructure Challenges - Mid Data Center	930	33	0
Gas Infrastructure Challenges - High Data Center	927	0	0
High Environmental - No Data Center	0	0	0
High Environmental - Low Data Center	0	0	0
High Environmental - Mid Data Center	144	0	0
High Environmental - High Data Center	2,949	1,543	0
Stable Markets - No Data Center	0	0	0
Stable Markets - Low Data Center	0	0	0
Stable Markets - Mid Data Center	0	0	0
Stable Markets - High Data Center	1,643	862	0

Figure 9-111: Resource Deficit for Secondary Frequency Response

Portfolio ↓	Resource Deficit for Secondary Frequency Response (Additional Storage or Generation, Islanded)													
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reference Case - No Data Center	18	18	18	18	18	12	12	12	12	12	12	12	12	11
Reference Case - Low Data Center	18	18	17	17	17	11	11	11	10	10	10	10	10	10
Reference Case - Mid Data Center	18	17	16	15	14	9	9	8	8	8	8	7	7	7
Reference Case - High Data Center	18	17	15	14	13	8	7	7	6	6	6	6	6	6
Gas Infrastructure Challenges - No Data Center	18	18	18	18	18	12	12	12	12	12	12	12	12	11
Gas Infrastructure Challenges - Low Data Center	18	18	17	17	17	11	11	11	10	10	10	10	10	10
Gas Infrastructure Challenges - Mid Data Center	18	19	18	17	16	10	10	9	9	9	8	8	8	8
Gas Infrastructure Challenges - High Data Center	18	17	16	15	13	8	8	7	7	6	6	6	6	6
High Environmental - No Data Center	19	19	19	20	20	22	25	32	37	44	50	59	68	70
High Environmental - Low Data Center	18	18	17	17	18	21	33	45	56	67	77	79	88	93
High Environmental - Mid Data Center	19	19	18	26	35	42	56	69	110	132	148	151	165	166
High Environmental - High Data Center	19	18	17	27	35	42	53	69	109	151	166	187	202	216
Stable Markets - No Data Center	18	18	18	18	18	12	12	12	12	12	12	12	12	11
Stable Markets - Low Data Center	18	19	19	18	18	12	12	12	11	11	11	11	11	11
Stable Markets - Mid Data Center	18	20	19	18	17	11	11	10	10	9	9	9	9	9
Stable Markets - High Data Center	18	19	18	16	15	10	9	8	8	8	7	7	7	7

9.3.4 Environmental

170 IAC 4-7-6(b)(3)(C)

The environmental analysis in the 2025 IRP focused on carbon metrics. Figure 9-112 shows total annual carbon generation emissions (in million tons) over time for the Reference Case for the No, Low, Mid, and High data center cases. This metric does not allow for the comparison of different load portfolios over time, whereas Figure 9-113 provides carbon emissions intensity on a pounds per MWh basis for each year. Over time, the carbon intensity of the resource mix declines. As seen in the Reference Case, the emission intensity of different data center load profiles is similar. By 2035, emission intensity is half what it was in 2009.

Figure 9-112: Total Carbon Emissions (Million Tons)

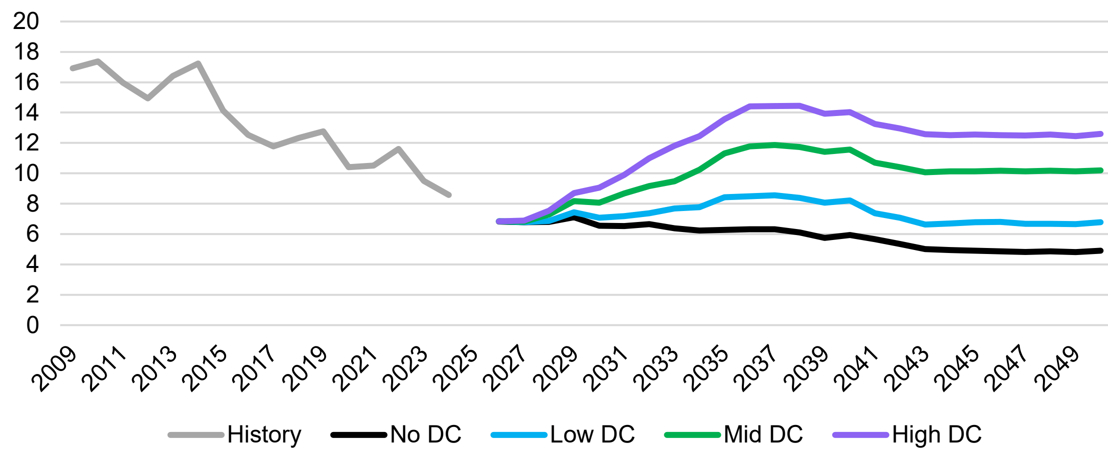


Figure 9-113: Total Carbon Emissions (lb/MWh)

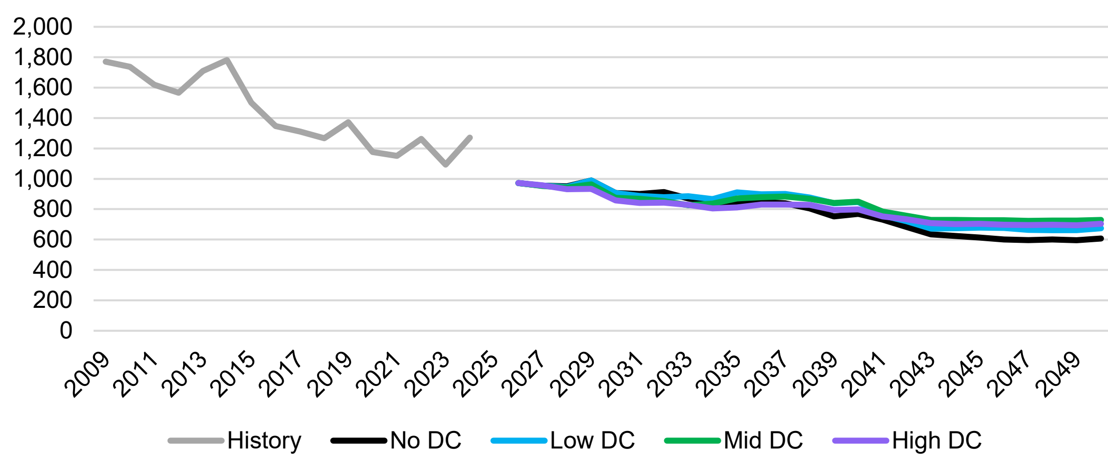
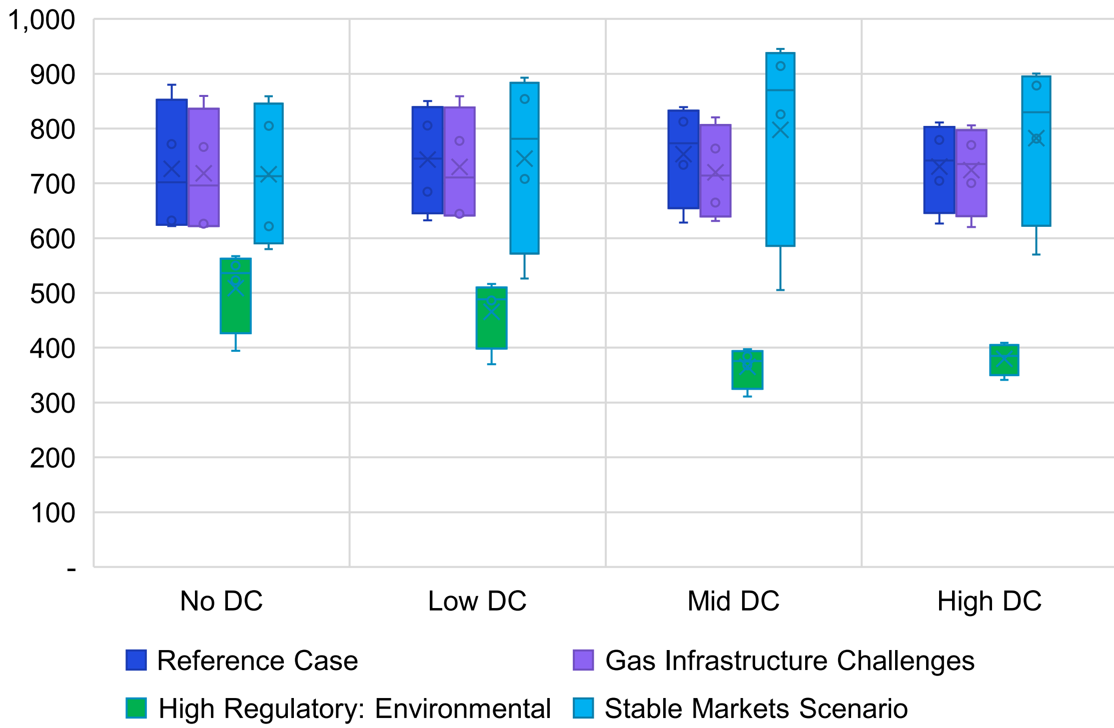


Figure 9-114 compares the average annual carbon intensity across portfolios and scenarios. The emission rates are similar across portfolios, except for the High Regulatory scenario, which has a higher penetration of renewables and storage.

Figure 9-114: Total CO2 Emissions (lb/MWh, Study Average)



While not part of the scorecard, data shown in Figure 9-115 contains total NOx and SO2 emissions through the study period for all 16 candidate portfolios.

Figure 9-115: NOx and SO2 Emissions (Thousand Tons)

Data Center Case	Portfolio	Total NOx Emissions (Thousand Tons)	Total SO2 Emissions (Thousand Tons)
No Data Center Load	Reference Case	43.3	2.5
	Gas Infrastructure Challenges	43.2	2.5
	High Regulatory: Environmental	29.0	2.2
	Stable Markets Scenario	55.3	2.6
Low Data Center	Reference Case	60.6	2.8
	Gas Infrastructure Challenges	39.9	2.6
	High Regulatory: Environmental	34.5	2.3
	Stable Markets Scenario	75.3	2.8
Mid Data Center	Reference Case	75.3	3.1
	Gas Infrastructure Challenges	51.4	2.9
	High Regulatory: Environmental	39.1	2.4
	Stable Markets Scenario	116.0	3.4
High Data Center	Reference Case	65.9	3.3
	Gas Infrastructure Challenges	50.3	3.3
	High Regulatory: Environmental	55.2	2.6
	Stable Markets Scenario	115.7	3.7

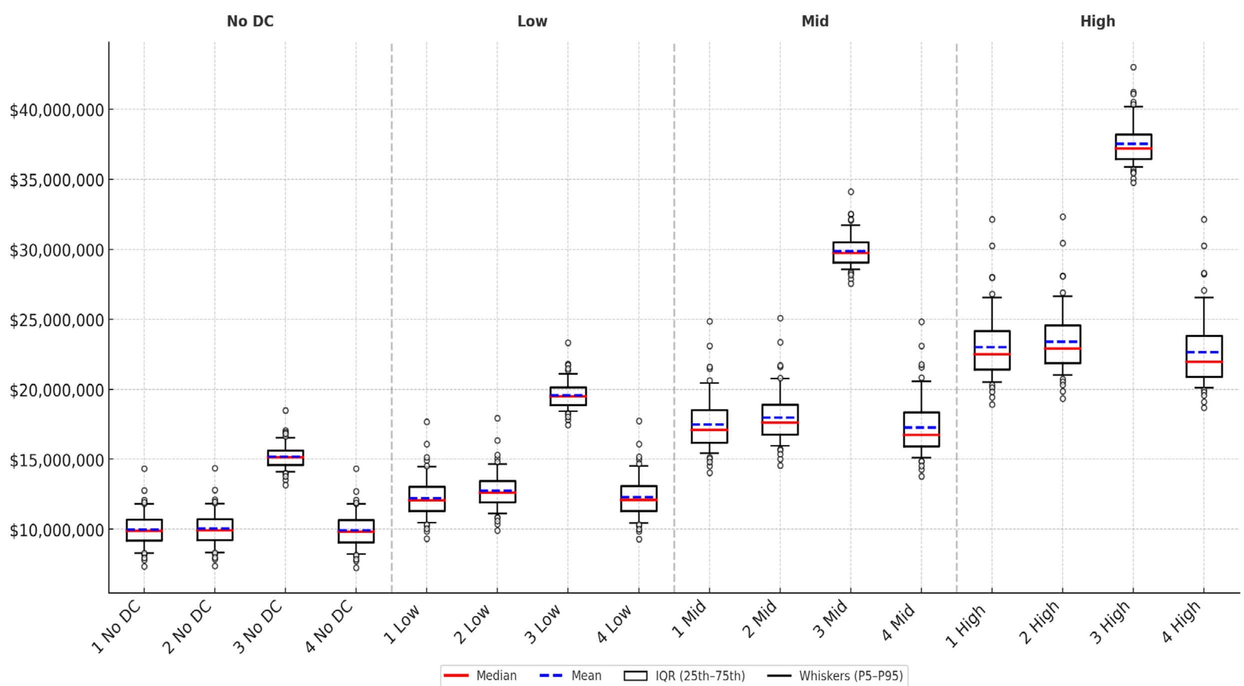
9.3.5 Risk & Opportunities

170 IAC 4-7-4(28) and 170 IAC 4-7-8(c)(4)(C)

AES Indiana engaged ACES to provide stochastic analysis. ACES conducted a weather-driven stochastic (WDS) analysis on all optimized portfolios across the four data center load scenarios, totaling 16 stochastically varied portfolios.

Figure 9-116 provides a comparison of the results for all stochastically varied portfolios. Scenarios are numbered 1-4 representing 1 Reference Case; 2 Challenged/High Gas; 3 High Regulatory; and 4 Stable Market. Also, scenarios are grouped by load level. Each portfolio's results are presented as box-and-whisker plots, with the box representing the 75% and 25% quartiles above and below the mean, and the whiskers representing the P95 and P5. The dotted blue line represents the mean, and the red line represents the median. Also, outliers are represented as dots above or below the P95 and P5. Figure 9-116 shows that, across load levels, Scenario 3: High Environmental Regulation has the narrowest PVRR distribution. This is because the High Environmental Regulation scenario contains the most renewable resources and the fewest natural gas resources of the scenarios. Scenarios with more natural gas resources are more exposed to fuel price volatility and, in turn, have a wider distribution. Additionally, the figure demonstrates that as more natural gas generators are added to serve higher data center loads, the PVRR distribution widens due to greater exposure to fuel price volatility.

Figure 9-116: PVRR Distributions for all Portfolios (2026, $000)



As we see Figure 9-116, the Reference Case, the Gas Infrastructure Challenges, and the Stable Market portfolios are not materially different in terms of risk and opportunity. However, the High Regulatory: Environmental portfolios are materially different in terms of risk and opportunity. This is because the portfolio swaps renewables resources for natural gas. Overall, this results in higher average costs, as the tax credits applied to renewable and storage resources are not embedded in the Reference Case.

At each load level, Scenario 3: High Regulatory: Environmental contains the narrowest PVRR distribution due to higher renewables volumes and, therefore, less fuel exposure. As natural gas capacity is added to serve a higher share of the data center load, the PVRR distribution widens due to greater fuel risk exposure. Portfolios that include more CCGT rather than CT exhibit lower P95-Mean due to the CCGT's lower heat rate, which provides a lower fuel cost hedge and better unit economics.

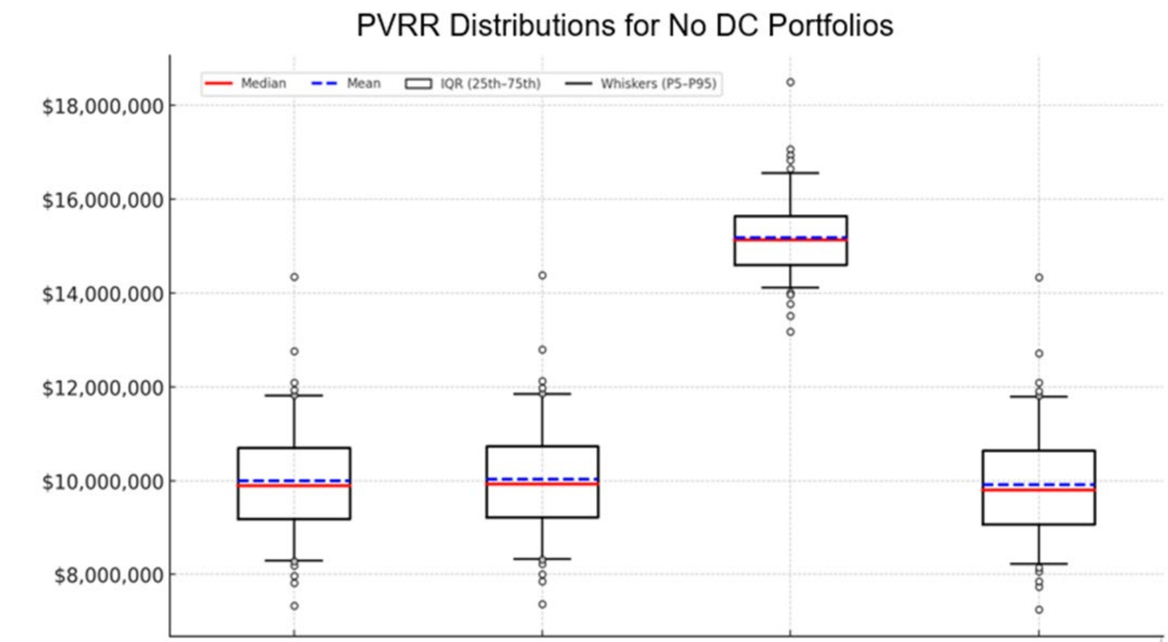
Figure 9-117 provides the results for the "No Data Center" set of scenarios. The box-and-whisker plot parameters are the same as above; however, these results also include P95 – Mean and Mean – P5. The P95 – Mean is a risk metric that measures the portfolio's exposure to higher-cost outcomes; the higher the value, the greater the risk of higher-cost outcomes. The Mean –

P5 is an opportunity metric that measures the portfolio's potential for lower-cost outcomes. Generally, the higher the Mean – P5, the greater the opportunity for lower-cost outcomes.

Figure 9-117 demonstrates that in the No Data Center set of portfolios, Scenario 3: High Regulatory: Environmental exhibits the lowest P95-Mean, indicating exposure to higher cost outcomes. This is driven by higher renewable versus natural gas resource volumes compared to the other portfolios and, in turn, less fuel price volatility risk. As shown and discussed in Figure 9-116 above, this is the same outcome across all data center load levels.

Figure 9-117 also demonstrates that there is not a material difference between the 1, 2, & 4 portfolios because little additional generation is added to AES Indiana’s existing portfolio under the No Data Center Load scenario.

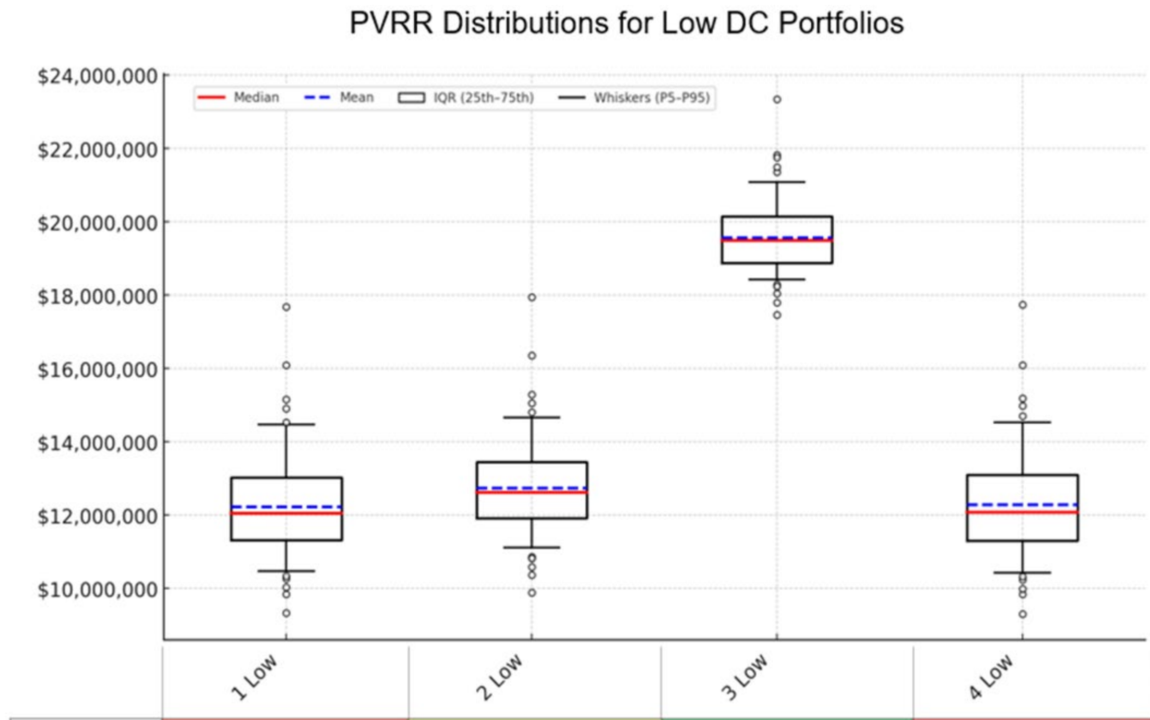
Figure 9-117: Stochastic Results- No Data Center Load



	1 No DC	2 No DC	3 No DC	4 No DC
P95 - Mean	$ 1,821,399	$ 1,818,145	$ 1,384,780	$ 1,877,576
Mean - P5	$ 1,696,232	$ 1,694,724	$ 1,070,702	$ 1,692,280

Figure 9-118 provides the results for the Low Data Center load portfolios. Of note, the Figure shows that portfolios that include more CCGT rather than CT exhibit a lower P95-Mean metric because CCGT’s lower heat rate results in a lower P95-Mean. In the Figure, Scenarios 1 & 4 both add CT to serve the Data Center load in 2035, whereas Scenario 2 adds CCGT. This lower heat rate means the units use less natural gas to produce power, i.e., produce power at a lower cost. This acts as a hedge against low spark spread, low power prices, or high gas prices. CCGTs may operate and produce power at market prices when it is uneconomic for CTs to operate—in this case, power would need to be purchased from the market to cover the CT units not producing.

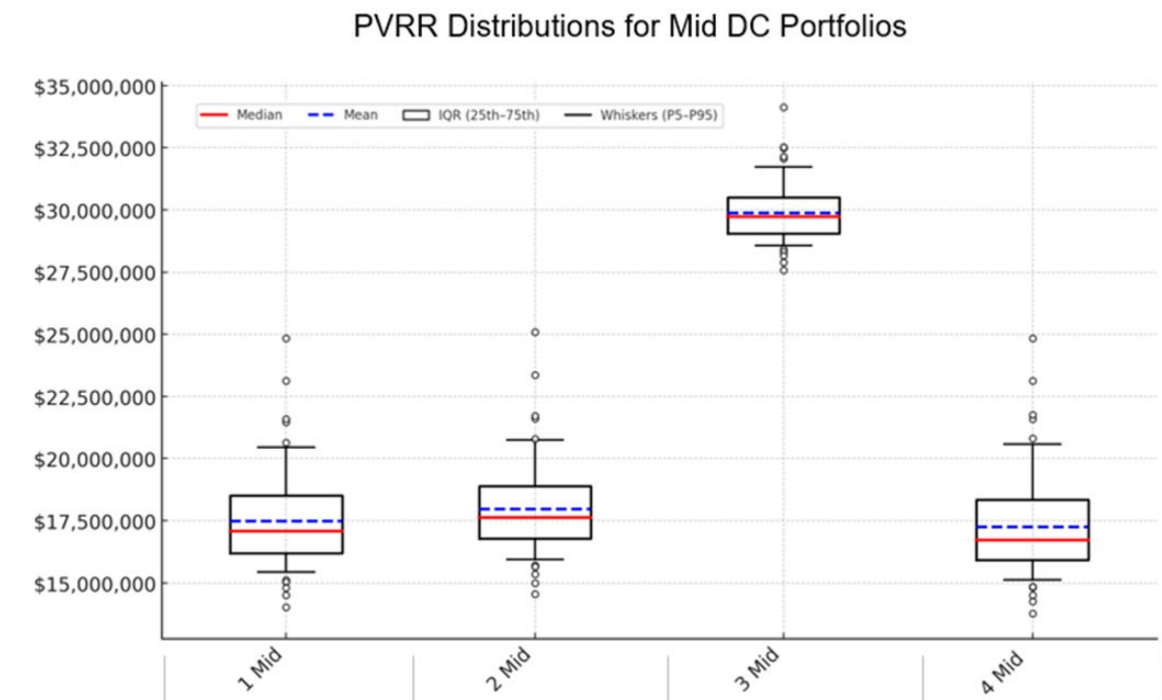
Figure 9-118: Stochastic Results – Low Data Center Portfolios



	1 Low	2 Low	3 Low	4 Low
P95 - Mean	$ 2,254,228	$ 1,943,443	$ 1,545,169	$ 2,276,621
Mean - P5	$ 1,756,267	$ 1,622,128	$ 1,143,957	$ 1,857,177

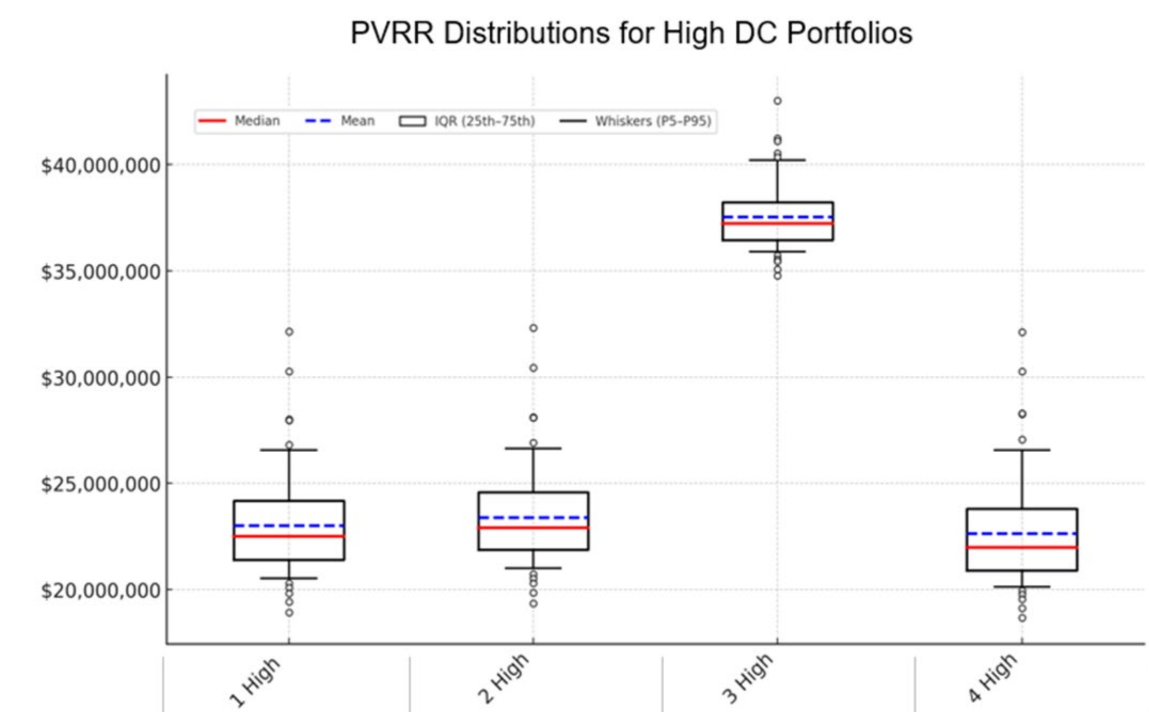
Figure 6 & 7 provide the results for the Mid Data Center and High load sets of portfolios. The stochastic results are generally similar when comparing these sets of portfolios. At both load levels, Scenario 4 adds mostly CT and little/no CCGT to serve the data center load, resulting in the highest P95-Mean and the greatest risk of higher-cost outcomes. By comparison, Scenarios 1 & 2 include more CCGT resources, which provide a hedge against outcomes with low spark spreads, as previously discussed.

Figure 9-119: Stochastic Results – Mid Data Center Portfolios



	1 Mid	2 Mid	3 Mid	4 Mid
P95 - Mean	$ 2,992,200	$ 2,803,457	$ 1,900,700	$ 3,366,492
Mean - P5	$ 2,050,211	$ 2,022,308	$ 1,295,868	$ 2,132,937

Figure 9-120: Stochastic Results – High Data Center Portfolios



	1 High	2 High	3 High	4 High
P95 - Mean	$ 3,571,289	$ 3,274,101	$ 2,692,545	$ 3,972,000
Mean - P5	$ 2,502,800	$ 2,392,576	$ 1,634,476	$ 2,532,459

9.3.6 Additional Scenarios and Sensitivities

170 IAC 4-7-4(28)

AES Indiana evaluated seven additional scenarios and sensitivities to address specific items of uncertainty in the IRP modeling. This section details the results of those studies.

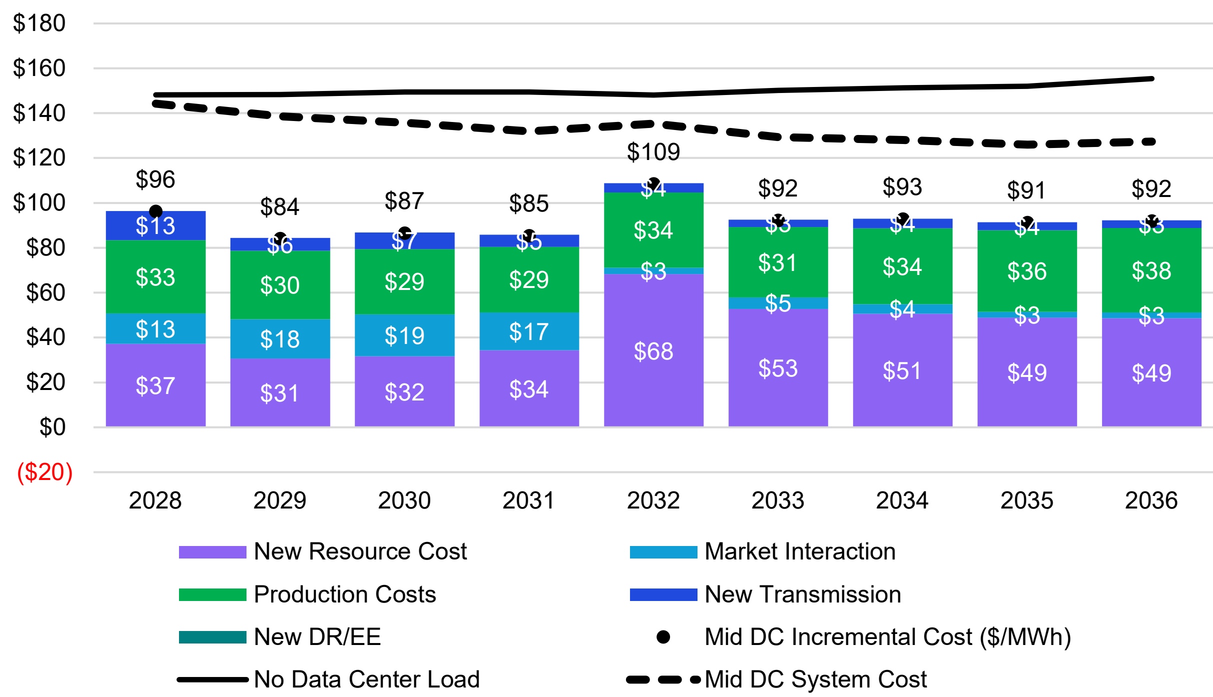
Data Center Transmission Investment

Figure 9-121 contains annual system average rates with varying levels of required transmission investment associated with the data center load. The Low and High investment levels are all within 1-2% of the Base cost, indicating a relatively small impact of the assumed transmission cost on the overall annual revenue requirement. Figure 9-122 shows the incremental cost in $/MWh for the Mid Data Center case (Reference Case) compared to the No Data Center case. The transmission cost at the base level represents incremental costs of $6-13/MWh during the load ramp and $4-5/MWh when the load reaches the full ramp by the end of 2035.

Figure 9-121: System Average Rate with Base, Low, and High Transmission Costs (Nominal $/MWh)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	15-Year Levelized ($/MWh)	Diff. from Mid Cost
No Data Center Load	$149	$145	$148	$149	$150	$150	$148	$150	$152	$152	$156	$159	$160	$164	$166	$152	-
Low Data Center Load																	
Mid Cost	$149	$145	$147	$145	$144	$143	$140	$142	$140	$142	$142	$145	$146	$148	$150	$145	-
Low Cost	$149	$145	$147	$145	$144	$142	$140	$142	$140	$142	$142	$144	$145	$148	$150	$145	-0.2%
High Cost	$149	$145	$148	$146	$145	$143	$141	$143	$141	$143	$143	$145	$146	$149	$151	$145	0.5%
Mid Data Center Load																	
Mid Cost	$149	$146	$144	$139	$136	$132	$136	$129	$128	$126	$128	$129	$130	$131	$133	$136	-
Low Cost	$149	$145	$144	$138	$135	$131	$135	$129	$127	$125	$127	$128	$130	$131	$132	$135	-0.5%
High Cost	$149	$147	$145	$140	$138	$134	$137	$131	$130	$128	$129	$131	$132	$133	$134	$137	1.4%
High Data Center Load																	
Mid Cost	$149	$146	$142	$134	$137	$126	$126	$121	$125	$119	$121	$122	$122	$122	$123	$131	-
Low Cost	$149	$145	$141	$134	$135	$125	$125	$120	$123	$117	$120	$121	$121	$121	$122	$130	-0.8%
High Cost	$149	$148	$144	$136	$139	$129	$128	$123	$127	$121	$123	$124	$124	$124	$125	$133	2.0%

Figure 9-122: Incremental Cost of Reference Case - Mid Data Center Load - Compared to No Data Center Load (Nominal $/MWh)



SMR Breakeven Analysis

The SMR breakeven analysis enables AES Indiana to identify cost points where an SMR makes economic sense for its customers. The unsubsidized CAPEX before AFUDC for a new SMR in the IRP was around $8,900/kW in 2035. While national and international efforts to develop SMR technology ramp up, the technology is new and remains a very high capital cost option for deployment, and as such, it was not selected in any scenario or portfolio in the IRP capacity expansion process.

Figure 9-123 contains the capital cost that SMR needs to be at, after all subsidies, loans, and AFUDC, for the portfolio to have an NPV equal to the optimized portfolio in each scenario evaluated. In the Reference Case, with natural gas prices in the $3-4/MMBtu range, no environmental restrictions on CCGT output, SMR would need to be at or below the cost of a CCGT to displace a CCGT economically, as the high operating costs (i.e., fixed O&M) offset fuel savings. In Scenario 2, with sustained high natural gas prices, the SMR is more economical, reducing the breakeven cost by about 50%. In Scenario 3, with environmental regulations on CCGT output, high natural gas prices, and high load due to electric vehicles and beneficial electrification, the breakeven cost improves again. However, even in this case, the all-in cost after subsidies and AFUDC must be half the base assumption in the IRP.

While SMRs have the potential to provide zero-carbon, baseload power that matches the load profiles of new data center customers, significant progress is needed on the cost side to make SMRs economically viable. Higher gas prices, federal carbon legislation, and continued increases in the cost of traditional thermal and renewable energy sources could improve SMR's economic position in the future.

Figure 9-123: SMR Cost[63] to Breakeven with Optimized Portfolio (High Data Center Load)

Enhanced RAP Scenarios

Stakeholders requested additional modeling that included Enhanced RAP ("ERAP") C&I bundles as selectable resources instead of RAP bundles. AES Indiana ran full-capacity expansion and dispatch runs for the Reference Case scenario across all data center cases. AES Indiana ran two versions: one replacing all vintages of RAP with ERAP, and another replacing only the first vintage. The resulting portfolios were similar, with some slight modifications in resource builds. Costs, as shown in Figure 9-124, were higher with ERAP than RAP, but not substantially higher. AES Indiana will further consider and evaluate the benefits of RAP versus ERAP with its stakeholders.

[63] Breakeven cost represents the fully subsidized, final cost of an SMR after tax credits and AFUDC

Figure 9-124: ERAP vs. RAP Portfolios – 10-Year System Cost ($/MWh)

	With RAP	With ONLY FIRST ERAP (CI_V1)	With ERAP
No Data Center Load	$149.08	$149.41	$149.54
Low Data Center Load	$144.44	$144.71	$144.71
Mid Data Center Load	$137.86	$138.03	$138.04
High Data Center Load	$134.37	$134.48	$134.49

Figure 9-125: Installed Capacity Changes, ERAP vs. RAP Portfolios, Reference Case (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
No Data Center Load															
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	2	4	5	6	7	7	8	9	9	10	10	10	11	11
Battery Storage	0	0	0	0	0	0	0	20	20	20	20	40	40	40	60
Gas Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	(54)	(54)	0	(54)	(54)
Market: Winter	0	(1)	(2)	(3)	(4)	(4)	(5)	(18)	(18)	(18)	31	20	(28)	21	7
Market: Summer	0	(2)	(3)	(5)	(5)	(6)	(6)	0	0	0	0	0	(3)	0	(11)
Low Data Center Load															
Demand Response	0	0	0	1	1	2	2	2	3	3	4	4	4	4	4
Energy Efficiency	0	2	4	5	6	7	7	8	9	9	10	10	10	11	11
Battery Storage	0	0	0	0	0	0	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Gas Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market: Winter	0	(1)	(3)	(4)	(5)	(6)	7	0	4	0	2	1	0	0	(0)
Market: Summer	0	(2)	(4)	(5)	(7)	(8)	0	0	0	0	0	0	0	0	0
Mid Data Center Load															
Demand Response	0	0	0	2	4	7	10	10	11	11	11	12	12	12	12
Energy Efficiency	0	2	4	5	6	7	7	8	9	9	10	10	10	11	11
Battery Storage	0	0	(20)	0	0	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Gas Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market: Winter	0	(1)	14	(5)	(8)	2	0	(3)	(4)	(5)	(6)	(8)	(8)	(8)	(9)
Market: Summer	0	(2)	13	(7)	(11)	(0)	0	0	0	0	0	0	0	0	0
High Data Center Load															
Demand Response	0	0	0	1	1	2	2	2	3	3	4	4	4	4	4
Energy Efficiency	0	2	4	5	6	7	7	8	9	9	10	10	10	11	11
Battery Storage	0	0	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Gas Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market: Winter	0	(1)	0	12	0	9	0	6	0	3	2	1	0	0	(0)
Market: Summer	0	(17)	(2)	(3)	0	(5)	0	0	0	0	0	0	0	0	0

Tax Credit Scenarios

Stakeholders requested a scenario with the ITC and PTC reinstated per the original Inflation Reduction Act to isolate the impacts of the One Big Beautiful Bill Act tax credit changes on portfolio selections. AES Indiana ran four additional capacity expansion runs, one for each data center case. As shown in Figure 9-126, the only scenario that resulted in more solar was the No Data Center case, in which 50 MW of solar was selected through 2040. No additional wind was selected in any scenario.

AES Indiana took an additional step in the model, identifying the selection point for new solar in the Reference case by decreasing the cost from $90/MWh to $30/MWh in $10/MWh increments. The cost of solar was held constant throughout the study, rather than following traditional learning curves and shapes over time. The intent was to isolate the impact of solar and identify the tipping point at which solar is selected. The results showed that solar began being selected at $50/MWh, and the model reached the maximum solar additions allowed below that cost.

While this cost is below what AES Indiana received in the IRP (most bids were in the $70-$80/MWh range), it does not preclude AES Indiana from pursuing additional solar projects if they could add value to customers. The location, time to power, contract type, duration, and other factors could yield more value than how utility-scale solar was modeled in the IRP. AES Indiana will evaluate all available projects as part of the 2024 All-Source RFP and on an ongoing basis as part of normal utility resource planning efforts.

Figure 9-126: Annual New Solar Installed Capacity (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
No Data Center Load														
Ref. Case	0	0	0	0	0	0	0	0	0	0	0	0	0	0
w/ Tax Credits reinstated and extended	0	0	0	0	0	0	0	0	25	50	50	50	50	50
Low Data Center														
Ref. Case	0	0	0	0	0	0	0	0	0	0	0	0	0	0
w/ Tax Credits reinstated and extended	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mid Data Center														
Ref. Case	0	0	0	0	0	0	0	0	0	0	0	0	0	0
w/ Tax Credits reinstated and extended	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Data Center														
Ref. Case	0	0	0	0	0	0	0	0	0	0	0	0	0	0
w/ Tax Credits reinstated and extended	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mid Data Center: Reference Case														
Mid DC: $30/MWh Solar	1,000	2,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Mid DC: $40/MWh Solar	1,000	2,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Mid DC: $50/MWh Solar	150	350	350	350	350	350	350	350	350	350	350	350	350	350
Mid DC: $60/MWh Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mid DC: $70/MWh Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mid DC: $80/MWh Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mid DC: $90/MWh Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Data Center Load Factor Sensitivities

The load factor sensitivity analysis provides a look at potential cost risks to the portfolio and AES Indiana customers if a new large load customer, which is expected to be at a very high load factor (90%) operates less than expected. This is important to understand in the context of AES Indiana using a $/MWh system rate as a metric in this IRP. If the load factor is lower, the MWh denominator is smaller, and the rate will be higher, all other things equal.

Figure 9-127 contains a chart with the annual system cost rate in $/MWh for the Mid Data Center, Reference Case portfolio, and Figure 9-128 contains the 10-year levelized cost rate for all data center cases in the Reference Case scenario. Each 5% reduction in load factor increases the system cost rate by $1-3/MWh, with the same fixed costs spread over fewer MWh. There is some offset with lower fuel and purchased power costs with lower load. AES Indiana could protect customers with minimum demand charges, which ensure that the incremental fixed costs are covered by the new load, regardless of actual usage.

Figure 9-127: Reference Case – Mid Data Center – Annual System Rate (Nominal $/MWh)

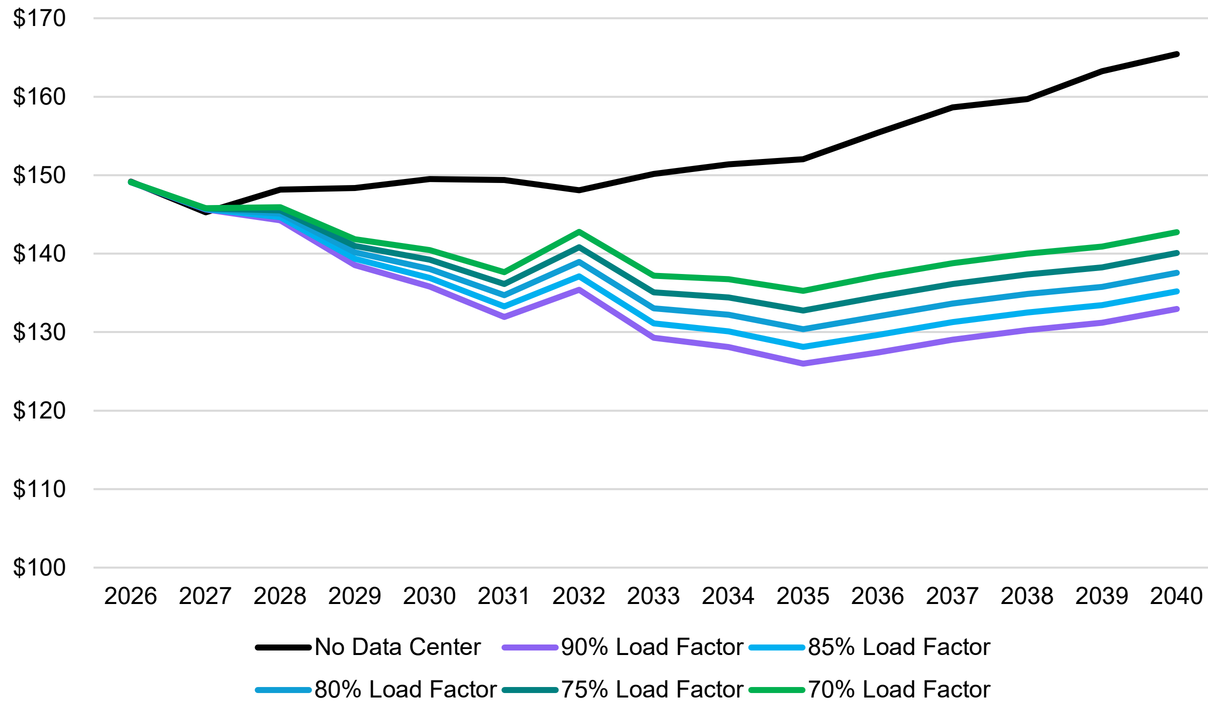


Figure 9-128: 10-Year Levelized Supply Cost ($2026/MWh)

	0%	70%	75%	80%	85%	90%
No Data Center	$149					
Low Data Center		$146	$146	$145	$145	$144
Mid Data Center		$142	$141	$140	$139	$138
High Data Center		$140	$139	$137	$136	$134

Data Center Early Exit Sensitivity

Stakeholders requested a sensitivity analysis to see what would happen if a data center committed and did not appear, or if a data center terminated their contract early. Given the wide range of possible variations, AES Indiana modeled two scenarios to help contextualize the types of risks this situation could entail.

However, it is important to note that customers can be protected during the contracting phase with new load customers by requiring large load customers to cover certain costs.

For AES Indiana, ways to mitigate risk include, but are not limited to, the following:

→ Minimum contract terms

→ Exit and/or contract volume reductions

→ Consistent and more frequent re-evaluation of supply and demand

→ Market capacity purchases and sales

→ Economic development integration (e.g., finding new large load customers)

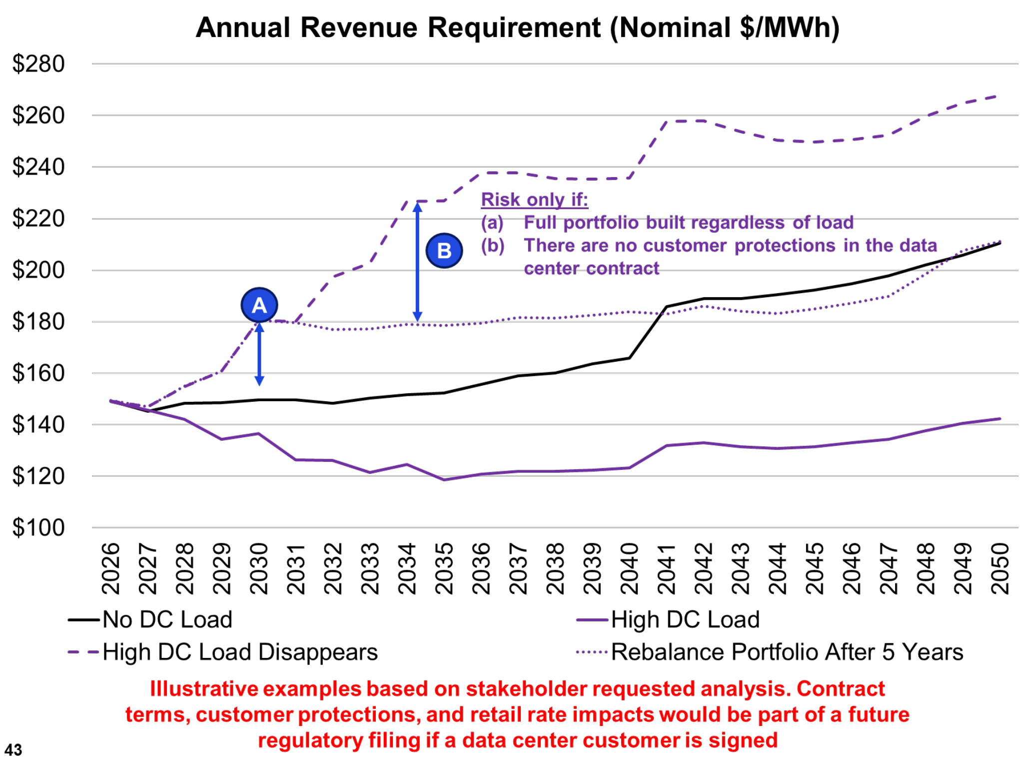
→ Potential retirement of existing units

Figure 9-129 looks at two options: (A) AES Indiana plans for data centers, and they do not materialize, and (B) a world where AES Indiana rebalances its portfolio upon learning that the data centers will not come.

In sensitivity A, if AES Indiana plans for data centers that do not materialize, system rates would be higher than in a world where it did *not* plan for those data centers. This represents an extreme, or bookend, scenario: AES Indiana would not continue to build its portfolio in perpetuity, assuming the load materializes, and would include contractual protections for customers.

Sensitivity B assumes that AES Indiana has to contract resources for the next five years due to supply chain constraints. Then, AES Indiana assumes that the load does not materialize, so AES Indiana rebalances the portfolio in Year 6 (in 2031). The costs are higher, but not as high as scenario A.

Figure 9-129: Data Center Leaves Sensitivity (Annual Revenue Requirement, Nominal $/MWh)



The costs in Figure 9-130 show the magnitude of the risk. It highlights the risk that AES Indiana may need to hedge using contractual tools or other methods.

Figure 9-130: Data Center Leaves Sensitivity – Levelized Supply Costs ($/MWh)

	No Data Center Load	High Data Center Load	High Data Center Load Does Not Materialize	High Data Center: AES Rebalances After 5 Years
10-Year Levelized Supply Cost	$149	$134	$178	$166
25-Year Supply Cost	$161	$132	$206	$175

Stable Market Variation

It was requested that AES Indiana modify the new thermal capital costs in the Stable Market portfolio so that they do *not* reflect any capital cost declines until after 2031. The Stable Markets Scenario assumed immediate cost reductions. However, that may not be likely in this environment. This sensitivity is intended to maintain the supply chain constraints facing new resources in the short term. AES Indiana adjusted capital costs for all resources, as constraints exist across resource types. Costs were Reference costs from 2026-2030, then straight line blended into Stable Market costs by 2035. As shown in Figure 9-131, the blended portfolio has a higher rate than the Stable Markets portfolio.

The resource mix of the resulting portfolios did not change significantly, resulting in a similar ranking of portfolios by cost. AES Indiana is active in the market for new resources and will continue to monitor new resource costs.

Figure 9-131: Stable Market Stakeholder Requested Cost Variation – Levelized Supply Costs

	Blended	Stable Markets
10-Year Levelized Supply Cost (2026$/MWh, 2025-2035)		
No DC	$153.90	$153.90
Low DC	$146.37	$146.34
Mid DC	$136.40	$135.26
High DC	$131.31	$129.46
25-Year Supply Cost (2026$/MWh, 2026-2050)		
No DC	$167.36	$167.34
Low DC	$151.61	$151.16
Mid DC	$133.86	$132.61
High DC	$125.48	$123.54

9.4 Preferred Resource Portfolio and Final Scorecard

170 IAC 4-7-4(9), 170 IAC 4-7-6(a)(2), IAC 4-7-8(b)(2), 170 IAC 4-7-8(c)(1)-(3), 170 IAC 4-7-8(c)(7), 170 IAC 4-7-8(c)(10), and 170 IAC 4-7-9(c)(3)

The 2025 IRP was precedent-breaking for AES Indiana; it solved for dramatically different load levels. AES Indiana has an obligation to serve customers within its service territory, and the IRP looked to guide how to serve these load levels under various conditions.

While there is interest in the AES Indiana service territory, as of October 2025, no Energy Services Agreements have been signed with any large customers. AES Indiana, therefore, selects two preferred resource portfolios: the Reference Case – No Data Center Load and the Reference Case – Mid Data Center Load. Unlike previous IRPs, which announced a single plan, this dual approach allows AES Indiana to prepare to meet its service requirements under different outcomes. This reflects that if new large loads were to be located within the AES Indiana service territory, AES Indiana would have to install additional resources. However, if the loads go elsewhere, then AES Indiana would not have to install additional resources.

Figure 9-132: Reference Case Portfolio Additions: Installed Capacity (MW)

		2027	2028	2029	2030	2031	2032
Demand Response	No Data Center Load	44	61	107	130	144	152
	Mid DC Load	44	61	105	124	133	138
Energy Efficiency	No Data Center Load	34	57	78	98	116	133
	Mid DC Load	34	57	78	98	116	133
Battery Storage	No Data Center Load		20	20	20	20	40
	Mid DC Load		200	360	580	860	860
Gas CCGT	No Data Center Load						
	Mid DC Load						700
Gas CT	No Data Center Load						
	Mid DC Load						
Gas Reciprocating Engines	No Data Center Load						
	Mid DC Load						
Solar	No Data Center Load						
	Mid DC Load						
Wind	No Data Center Load						
	Mid DC Load						
Summer Capacity Market Purchases/(Sales)	No Data Center Load	2	27	(10)	(15)	(17)	(33)
	Mid DC Load	2	34	49	48	(0)	(50)
Winter Capacity Market Purchases/(Sales)	No Data Center Load	22	41	31	28	32	44
	Mid DC Load	23	(43)	22	49	48	(50)

The Preferred Resource Portfolio will be largely dependent on new, signed data center customers. To the extent AES Indiana reaches an agreement with a new data center customer, resources will be pursued in line with the Reference Case portfolios, notably the Mid Data Center Case. Resource selection will be subject to large load contracting, availability, and cost-benefit analysis. All resource additions via PPA, acquisition, or self-development will be subject to IURC approval in a future regulatory filing.

Several key factors could impact the Preferred Resource portfolios:

→ Resource accreditation: higher or lower firm capacity value for storage, gas, or existing resources could impact AES Indiana's capacity position, requiring more or fewer additions in the future.

→ MISO Reserve Margins: MISO is moving to the DLOL method for PY 28/29 forward. A reserve margin different from that modeled in the IRP could require a different volume of resource additions.

→ Market Availability/Resource Feasibility: AES Indiana will have to evaluate the likelihood of being able to contract for or construct the resources identified in the IRP.

→ Data Center Load Ramp: The IRP modeled new, generic data center load ramps at different volumes, ramping up linearly over time. If a new data center customer is signed, AES Indiana will calibrate the Preferred Resource Portfolio to match the new customer's actual projected ramp.

The preferred portfolios support the four scorecard evaluation categories.

1) *Affordability*

→ Under current market conditions, the Reference Case portfolios have lower PVRRs and levelized supply costs compared to other portfolios.

2) *Reliability, Stability & Resiliency*

→ All portfolios are designed to meet a minimum seasonal reserve margin as required, to limit capacity purchase to 50 MW per season, and to limit energy purchases and sales to 20% annually.

→ Portfolios have large amounts of dispatchable (storage and natural gas) capacity and firm dispatchable capacity.

3) *Risk & Opportunity*

→ All portfolios, except for the High Regulatory optimized portfolios, show similar risk and opportunity profiles because of exposure to gas prices. The High Regulatory does not have this exposure. However, these High Regulatory profiles cost 50% more than a Reference Case portfolio if current market conditions endure.

→ However, should the Reference Case portfolios be subject to additional environmental regulations (such as capacity factor limits on new combined cycles) or should alternatives like renewable and storage become cheaper, the Reference Case portfolios will be subject to environmental expenditures. However, these expenditures, which are $234 million in 2026 dollars in the Reference Case – No Data Center Load, are less than the $5.3 billion (in 2026 dollars) cost increase that would have been required to pursue those alternative resource options and remain in a current market condition world.

4) Environmental

→ Reference Case portfolios have similar carbon intensities and total carbon emissions as the Gas Infrastructure Challenges and Stable Markets Scenario.

9.4.1 Financial Impact of Preferred Resource Portfolio

170 IAC 4-7-8(c)(7)(A)-(D)

Figure 9-133 contains an annual view through 2036 for the revenue requirement breakdown for the No Data Center, Reference Case portfolio. This portfolio assumes that no new large load or data center customers are added in the AES Indiana service territory.

With no new large load customers, AES Indiana maintains a relatively flat firm capacity position through 2032, with decreases in storage and solar ELCC in summer and winter triggering the need for incremental capacity additions over time. New EE and DR programs provide additional capacity and energy to the portfolio, delaying the need for additional resources.

The annual revenue requirement remains relatively flat over 10 years, as lower fuel price forecasts in the forward curve translate into lower fuel costs in the late 2030s and early 2030s—the expiration of the Lakefield PPA in 2032 results in further reductions in portfolio costs.

Figure 9-133: Year-over-Year Change in Revenue Requirement – Reference Case – No Data Center Load

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Expenses ($MM)	**$814**	**($26)**	**$22**	**($1)**	**($17)**	**($19)**	**($49)**	**($6)**	**($11)**	**$9**	**$26**	**($72)**
Energy Purchases	$89	($3)	$2	($14)	$27	$1	($2)	$3	($4)	$1	($7)	$4
Fuel	$390	$44	($9)	$13	($50)	($20)	($9)	($25)	($4)	$3	$7	($49)
Variable O&M	$132	($4)	$2	$3	($1)	($11)	($48)	($1)	$0	$1	$3	($57)
Fixed O&M	$183	($54)	$18	($11)	$1	$5	$4	$7	($7)	($0)	$11	($27)
Start Cost	$2	($1)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	($1)
Demand Response and Energy Efficiency	$0	$9	$6	$10	$6	$5	$3	$3	$3	$3	$3	$52
Capacity Purchases	$17	($16)	$2	($1)	($0)	$0	$1	($1)	$1	$1	($1)	($16)
Emissions	$1	($0)	$0	$0	($0)	($0)	($0)	$0	$0	($0)	$0	$0
Book Depreciation	$0	$0	$2	$0	$0	$0	$2	$6	$0	$0	$7	$17
Property Taxes	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$2	$3
Decommissioning	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$1
Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rate Base ($MM)	**$0**	**$0**	**$27**	**($3)**	**($3)**	**($3)**	**$24**	**$77**	**($14)**	**($14)**	**$128**	**$219**
Return on RB Grossed Up	$0	$0	$2	($0)	($0)	($0)	$2	$7	($1)	($1)	$11	$20
Total Revenue Requirement - Grossed Up	$814	($26)	$24	($1)	($18)	($19)	($47)	$1	($12)	$7	$37	($53)
Less: (revenues from energy and capacity)												
Energy Revenue ($MM)	$94	$27	($6)	$7	($19)	($2)	($12)	($15)	($14)	$12	$1	($22)
Capacity Revenue ($MM)	$2	$2	$0	$0	$0	$0	$1	$1	$0	$0	$0	$5
Incremental Revenue Requirement	**$718**	**($55)**	**$30**	**($9)**	**$2**	**($17)**	**($35)**	**$16**	**$2**	**($5)**	**$37**	**($35)**
Base 3% Inflation on T&D Rev. Req. ($MM)	$777	$23	$24	$25	$25	$26	$27	$28	$29	$30	$30	$267
Year-over-Year Revenue Requirement ($MM)	$2,096	($32)	$54	$16	$27	$9	($8)	$43	$30	$25	$67	$232

Figure 9-134 contains a 10-year forecast of the annual portfolio cost impacts by category for the Mid Data Center Reference case compared to the No Data Center Reference Case. This provides a detailed view of the cost changes required to serve the additional load. The final line of the table shows the incremental cost of the portfolio, representing the increase in cost per incremental addition of load (MWh). This incremental cost effectively represents a floor that the new load must cover to hold other customers harmless. As discussed throughout this report, AES Indiana would provide any customer rate impacts in a future regulatory filing if a new large customer is signed and AES Indiana seeks IURC approval to serve that customer via a new tariff, a customer-specific contract, new generation resources, or other filings necessary to serve the new load.

Figure 9-134: 10-Year Annual Revenue Requirement – Reference Case – Mid Data Center Load versus No Data Center Load (Annual Revenue Requirement Delta by Unit)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Expenses ($MM)										
Energy Purchases	$2	$9	$27	$20	$21	$7	$10	$18	$11	$11
Fuel	$2	$32	$66	$97	$130	$144	$172	$222	$280	$308
Variable O&M	$0	$1	$3	$4	$5	$20	$22	$24	$27	$26
Fixed O&M	$0	$5	$10	$16	$24	$67	$66	$81	$97	$110
Start Cost	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1
Demand Response and Energy Efficiency	($0)	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)
Capacity Purchases	$0	($1)	$2	$3	$1	($2)	($1)	($2)	($2)	($0)
Emissions	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1
Book Depreciation	$0	$17	$32	$52	$78	$149	$143	$166	$190	$207
Property Taxes	$0	$2	$4	$7	$11	$41	$40	$46	$53	$57
Decommissioning	$0	$2	$4	$6	$10	$12	$11	$11	$11	$12
Insurance	$0	$1	$2	$3	$4	$4	$3	$3	$3	$3
Rate Base ($MM)	**$0**	**$240**	**$425**	**$664**	**$955**	**$2,963**	**$2,690**	**$2,960**	**$3,219**	**$3,324**
Return on Rate Base	$0	$21	$38	$59	$86	$265	$241	$265	$288	$298
Total Revenue Requirement	$3	$89	$186	$266	$367	$706	$706	$835	$958	$1,031
Less: Energy and Capacity Revenue ($MM)										
Energy Revenue	($1)	($9)	($17)	($52)	($69)	($18)	($35)	($27)	($21)	($20)
Capacity Revenue	$0	$2	($0)	($1)	($1)	$3	$2	$0	$0	$0
Incremental Revenue Requirement	**$4**	**$97**	**$203**	**$319**	**$437**	**$721**	**$740**	**$862**	**$979**	**$1,051**
Total Revenue Requirement ($MM)	$4	$97	$203	$319	$437	$721	$740	$862	$979	$1,051
Transmission Revenue Requirement ($MM)	$16	$15	$15	$30	$29	$28	$28	$42	$41	$40
Total Rev Req. w/ Transmission ($MM)	**$20**	**$112**	**$218**	**$349**	**$466**	**$749**	**$767**	**$904**	**$1,020**	**$1,091**
Change in System Level Sales (GWh)	99	1,168	2,594	4,029	5,456	6,900	8,310	9,744	11,171	11,858
Incremental Cost to Supply New Load ($/MWh)	$200.38	$96.24	$84.08	$86.58	$85.46	$108.54	$92.32	$92.80	$91.29	$92.02

Section 10: Short-Term Action Plan and Conclusion

170 IAC 4-7-9(a), 170 4-7-9(b), 170 IAC 4-7-4(24), 170 IAC 4-7-6(b)(4), 170 IAC 4-7-8(c)(10), and 170 IAC 4-7-9

10.1 2025 Short-Term Action Plan

170 IAC 4-7-4(10)

Per IURC Rules (170 IAC § 4-7-9(a)), AES Indiana's Short Term Action Plan covers the next three years, 2026 through 2028, in this IRP. However, given the challenges and delays in procuring capacity in the current and foreseeable market, the Company intends to pursue supply-side projects selected by the EnCompass model through 2032. Please see Figure 10-1 for details.

AES Indiana's Short Term Action Plan balances affordability, reliability, stability, and resiliency, risk and opportunity, and environmental sustainability by:

→ Adding 130 MW of firm capacity in demand response by 2030 and 150 MW by 2032 whether or not data centers come online; this could be equivalent to 200 MW of installed capacity in summer 2032.

→ Adding 100 MW of energy efficiency by 2030 and 130 MW by 2032 whether or not data centers come online.

→ Adding up to 860 MW of installed battery storage by 2032, should a large load commit; otherwise, consider 40 MW.

→ Adding 700 MW of combined cycle in 2032 should a large load commit.

Resource selection will be subject to large load contracting, availability, and cost-benefit analysis. Short-term capacity market purchases or sales would be used only for rebalancing capacity positions and are subject to change based on resource accreditation, load forecast, MISO PRM, or other MISO capacity market rule changes. AES Indiana will reevaluate its generation portfolio every three years through the IRP process.

Figure 10-1: Short Term Action Plan

		2027	2028	2029	2030	2031	2032
Demand Response	No Data Center Load	44	61	107	130	144	152
	Mid DC Load	44	61	105	124	133	138
Energy Efficiency	No Data Center Load	34	57	78	98	116	133
	Mid DC Load	34	57	78	98	116	133
Battery Storage	No Data Center Load		20	20	20	20	40
	Mid DC Load		200	360	580	860	860
Gas CCGT	No Data Center Load						
	Mid DC Load						700
Gas CT	No Data Center Load						
	Mid DC Load						
Gas Reciprocating Engines	No Data Center Load						
	Mid DC Load						
Solar	No Data Center Load						
	Mid DC Load						
Wind	No Data Center Load						
	Mid DC Load						
Summer Capacity Market Purchases/(Sales)	No Data Center Load	2	27	(10)	(15)	(17)	(33)
	Mid DC Load	2	34	49	48	(0)	(50)
Winter Capacity Market Purchases/(Sales)	No Data Center Load	22	41	31	28	32	44
	Mid DC Load	23	(43)	22	49	48	(50)

10.1.1 Supply Side (Generation) Short-Term Action Plan

170 IAC 4-7-6(a)(2)

For the first time, AES Indiana proposes two preferred resource portfolios: one to address "business as usual" to serve AES Indiana's native load, and the other to fulfill AES Indiana's obligations to serve large loads.

If no large loads appear, AES Indiana's Short-Term Action Plan focuses on demand-side resources. Small amounts of battery storage could fill any incremental capacity needs over time.

Should a large load commit, AES Indiana will pursue additional battery storage, reaching up to 860 MW by 2032 in the Mid Data Center Load Case. Based on the modeled load ramp, AES Indiana would need to add a 700 MW natural gas combined-cycle unit in 2032 to meet the portfolio's additional energy and capacity needs.

Capacity purchases and sales will be used to rebalance AES Indiana's capacity position. In the event of larger deviations, AES Indiana will evaluate the need for additional resources to serve the load.

Supply-side generation selections focus on battery storage and combined cycle facilities. However, the IRP is a guidance document; specific resource selections will depend on factors such as economics, benefits, availability, location, and more. These selections are made through a competitive request for resources ("RFP") process, and the Commission approves selections through regulatory filing.

In the selection of specific resources to serve the load, AES Indiana may find that other resources are in the best interest of customers. For example, some battery storage facilities may come with interconnected solar or, perhaps there is limited availability of battery storage, but additional economic demand response. While AES Indiana will use the Short-Term Action Plan to guide decisions, it also understands that specific resource selections are subject to the regulatory process's guiding principles and will need to act accordingly.

10.1.2 Demand Side Management Short-Term Action Plan

170 IAC 4-7-6(b)(2)(F) and 170 4-7-9(c)(2)

In 2026, the Company plans to seek Commission approval to deliver DSM programs in 2027 through 2029 at levels consistent with those identified in the preferred portfolios of this IRP.

Energy efficiency was bundled by sector and by time period for selection in the EnCompass model; *Vintage 1* encompasses 2027 – 2029 and will serve as the basis for the next DSM program proposal. Figure 10-2 demonstrates the cumulative savings of the selected *Vintage 1*, and Figure 10-3 demonstrates the incremental savings.

Figure 10-2: Cumulative Energy Efficiency Targets - *Vintage 1 (2027-2029*)

Vintage 1 Bundles	Cumulative MWh (2027 – 2029)	Summer Capacity (2029, MW)
C&I	418,275	35
Res Tier1 (Res Behavior)	219,603	16
IQW[64]	57,655	6
IQ HEAR[65]	12,927	-
Total	708,460	57

Figure 10-3: Estimated Energy Efficiency Targets[66]

Vintage 1 - Incremental Net Savings (MWh)	2027	2028	2029
C&I V1	85,189	73,932	66,161
Res BEH Tier1 V1	50,467	51,972	52,901
IQW V1	11,047	9,513	9,075
Total Estimated Energy Efficiency Targets	146,704	135,418	128,137

[64] Income Qualified Weatherization (IQW) bundles were pre-selected in the model.
[65] Income Qualified Indiana Home Appliance Rebate (IQ HEAR) bundles were pre-selected in the model at no cost. These bundles are not utility-sponsored DSM and are not the responsibility of the utility to implement. Bundles were included to capture the effect of the state-sponsored program on the territory for planning purposes.
[66] IQ HEAR is not included as part of the Company's targets. Values include line losses and are presented at the generator-level.

AES will look to include the following demand response bundles:

- → DR Thermostat
- → DR Load Curtailment
- → DR BDR (Residential Behavioral Demand Response)[67]
- → DR TOU (Time-of-Use Rate)[68]

See Figure 10-4.

Figure 10-4: Estimated Demand Response Targets[69]

Summer Installed Capacity (MW)	2027	2028	2029
DLC Thermostat (Free Thermostat + BYOT)	53.8	56.1	59.0
C&I Load Curtailment	9.4	30.5	63.5
Res Behavioral DR	-	-	25.8
TOU Rate	-	-	2.0
Total	**63.2**	**86.5**	**150.4**
Summer Firm Capacity (MW)	**2027**	**2028**	**2029**
DLC Thermostat (Free Thermostat + BYOT)	37.6	39.3	41.3
C&I Load Curtailment	6.6	21.3	44.5
Res Behavioral DR	-	-	18.1
TOU Rate	-	-	1.4
Total	**44.2**	**60.6**	**105.3**

In addition to the bundles identified in Figure 10-5, bundles in Figure 10-5 were selected if no large loads enter the system. As a result, AES Indiana may also consider the targets identified in Figure 10-5. Those additional bundles include:

- → DR Battery
- → DR PTR

[67] New DR products were delayed for two years with the assumption that new products would require regulatory approval timing.
[68] See section 6.5 for further description of Time-of-use (TOU) modeling. New DR products were delayed for two years with the assumption that new products would require regulatory approval timing. Unlike other DSM and DR products or measures, TOU is a utility rate. Rate changes require greater company consideration, stakeholder input, and regulatory oversight compared to the traditional DSM or DR planning processes. Timing and implementation may vary from IRP assumptions.
[69] Installed Capacity includes line losses and are presented at the generator-level. Firm Capacity is based on the installed capacity with a 70% accreditation factor.

Figure 10-5: Additional Estimated Demand Response for Consideration[70]

Summer Installed Capacity (MW)	2027	2028	2029
Battery Storage	0.1	0.4	1.0
Res Peak Time Rebate	0.0	0.0	2.1
Total	**0.1**	**0.4**	**3.0**

Summer Firm Capacity (MW)	2027	2028	2029
Battery Storage	0.1	0.2	0.7
Res Peak Time Rebate	-	-	1.4
Total	**0.1**	**0.2**	**2.1**

Energy efficiency and demand response are significant components of AES Indiana's portfolio. In a world without large load additions, native load growth is met almost exclusively with these resources. In a world with large load growth, it serves as the foundation for the portfolio. AES Indiana will use the Short-Term Action Plan to guide its future filings; however, similar to supply-side resources, there are risks and opportunities with demand-side resources. These include, but are not limited to, factors like implementation risks, adopted behavior, output risks, and MISO accreditation. AES Indiana will work with its internal team, stakeholders, consultants, regulatory bodies, implementers, vendors, and others to support the implementation of energy efficiency and demand response in a cost-effective, reliable, and timely manner.

10.1.3 Transmission Short-Term Action Plan

AES Indiana has submitted the following transmission system projects to MISO via the MTEP Portal and is inclusive of only Transmission Owner ("TO") projects or the TO portion of the project) that are submitted for MTEP 25 and prior MTEP cycles.

MTEP 25 and prior submissions are as follows:

→ MTEP Number: 17886

- Replace Southeast Breakers to address reliability need from the annual short circuit analysis as required by NERC TPL-001-4 R2.3 & R2.8 results in breaker replacements at Southeast substation.
- Timing: 2025.
- Estimated Cost: $900,000.

→ MTEP Number: 21836

- Replace Sunnyside Breakers – Age and condition breaker replacements at Sunnyside substation: three (3) 345 kV breakers, two (2) 138 kV breakers.
- Timing: 2024.
- Estimated Cost: $5,100,000.

[70] *Id.*

→ MTEP Number: 21838

- Replace Southwest Breakers – Age and condition breakers replacements at Southwest substation: five (5) 138 kV breakers.
- Timing: 2024.
- Estimated Cost: $4,500,000.

→ MTEP Number: 21839

- Replacement West Breakers – Age and condition breaker replacements at West substation: three (3) 138 kV breakers.
- Timing: 2024.
- Estimated Cost: $2,400,000.

→ MTEP Number: 23107

- J993 / Brickyard Solar – Brickyard Solar is a 217 MVA solar facility, this project consists of any necessary transmission adjustments to enable the solar facility to interconnect to the transmission system.
- Timing: 2023.
- Estimated Cost: $20,000,000.

→ MTEP Number: 23568

→ MTEP Number: 23825

- Rockville Substation Reconfiguration – Rockville Substation reconfiguration is a substation modification to allow for more operational flexibility during outage and contingent situations and future load growth along the west portion of Marion County, Indiana.
- Timing: 2024.
- Estimated Cost: $9,000,000.

→ MTEP Number: 23831

- Gillette Substation – Gillette Substation is a new 138 kV, 80 MVA substation to serve new C&I customers near Indianapolis commercial business district. This project is also inclusive of any transmission adjustments necessary to allow the additional customer load to interconnection to the transmission system.
- Timing: 2024.
- Estimated Cost: $15,000,000.

→ MTEP Number: 23852

- R1011 / Petersburg Energy Center – Petersburg Energy Center is a 279.45 MVA solar facility, this project consists of any necessary transmission adjustments to enable the solar facility to interconnect to the transmission system.
- Timing: 2024.
- Estimated Cost: $4,000,000.

→ MTEP Number: 23893

- Winding Ridge Substation – Winding Ridge Substation is a new 138 kV, 80 MVA substation to serve new and supporting RCI customers along the east side of Marion County. This project is a joint project with Wabash Valley Power Association.
- Timing: 2024.
- Estimated Cost: $15,000,000.

→ MTEP Number: 24273

- Airtech Substation – Airtech Substation is a new 138 kV, 40 MVA substation to serve new and support existing RCI customers along west side of Marion County. This project is a joint project with Wabash Balley Power Association.
- Timing: 2026.
- Estimated Cost: $10,700,000.

→ MTEP Number: 24274

- Maloney-Reservoir Loop – The Maloney-Reservoir Loop project is a new 138 kV expansion with a few substations to serve new and existing RCI customers along the west side of Marion County.
- Timing: 2026-2029
- Estimated Cost: $52,800,000.

→ MTEP Number: 24293

- Pleasant Acres Substation – The Pleasant Acres Substation is a new 138 kV, 22.4 MVA substation to serve new and support existing RCI customers along the east side of Marion County. This project is a joint project with Wabash Valley Power Association. This project is intended to serve NineStar customers.
- Timing: 2025.
- Estimated Cost: $10,000,000.

→ MTEP Number: 25268

- Petersburg Autotransformers – This project replaces the existing 345-138 kV Petersburg East & West Autotransformers with 500 MVA rating transformers to accommodate growing transmission demand on the 138 kV network around the Petersburg substation.

- Timing: 2028
- Estimated cost: $21,182,115.

→ MTEP Number: 25353

- Replace one 138 kV Breaker at Southwest Substation.
- Timing: 2026.
- Estimated Cost: $ 900,000.

→ MTEP Number: 25354

- Replace three 138 kV Breakers at Parker Substation.
- Timing: 2025
- Estimated Cost: $2,700,000.

→ MTEP Number: 25355

- Replace four 138 kV Breakers at Northwest Substation.
- Timing: 2025
- Estimated Cost: $3,600,000.

→ MTEP Number: 25367

- Hawthorne Substation - Hawthorne Substation is a new 138 kV, 80 MVA substation to serve new RCI customers in central Marion county. This project is also inclusive of any transmission adjustments necessary to allow the additional customer load to interconnection to the transmission system.
- Timing: 2025
- Estimated Cost: $12,327,513.

→ MTEP Number: 25372

- Monrovia Substation - Monrovia Substation is a new 345 kV – 138 kV, 80 MVA substation to serve new and support existing RCI customers in south-west Marion county and Morgan county.
- Timing: 2031
- Estimated Cost: $ 35,348,000.

→ MTEP Number: 25383

- Replace three 138 kV Breakers at South Substation.
- Timing: 2025

- Estimated Cost: $2,700,000.

→ MTEP Number: 25384

- Replace five 138 kV Breakers at East Substation.
- Timing: 2025
- Estimated Cost: $ 4,500,000.

→ MTEP Number: 25385

- Replace six 345 kV Breakers at Petersburg Substation.
- Timing: 2026
- Estimated Cost: $5,400,000.

→ MTEP Number: 25386

- Replace two 138 kV Breakers at North Substation.
- Timing: 2026
- Estimated Cost: $1,800,000.

→ MTEP Number: 25387

- Replace one 138 kV Breaker at Prospect Substation.
- Timing: 2025
- Estimated Cost: $716,236.

→ MTEP Number: 25389

- Replace two 138 kV breakers at Northeast.
- Timing: 2026
- Estimated Cost: $1,800,000.

→ MTEP Number: 25390

- Replace two 138 kV breakers at Brookwood.
- Timing: 2026
- Estimated Cost: $1,800,000.

→ MTEP Number: 25401

- Northwest Substation – Expanding the Northwest substation to accommodate a 138-34.5 kV 66.6 MVA Northwest Transformer to provide support to Central Indianapolis's 34 kV network.
- Timing: 2025
- Estimated Cost: $2,600,000.

→ MTEP Number: 25402

- Replace one 138 kV breaker at Petersburg.
- Timing: 2026
- Estimated Cost: $900,000.

→ MTEP Number: 50032

- MISO Generator Project R1021 and R1022. Perform transmission work to accommodate the Pike County Energy Storage project.
- Timing: 2025
- Estimated Cost: $3,000,000.

→ MTEP Number: 50095

- Upgrade Stout CT - CT 4 and 5 protective relaying to redundant relaying.
- Timing: 2026
- Estimated Cost: $300,000.

→ MTEP Number: 50096

- Upgrade Stout CT - CT Bus protective relaying to redundant relaying.
- Timing: 2026
- Estimated Cost: $125,000.

→ MTEP Number: 50722

- Pond Creek substation – A Pond Creek 345 : 138 kV Substation, interconnecting into the 138 kV network around nearby Petersburg substation, to accommodating continued growth of 138 kV transmission demand.
- Timing: 2029
- Estimated Cost: $40,000,000.

→ MTEP Number: 50723

- Petersburg Substation Line modification – Terminal equipment replacement at Petersburg to uprate the Petersburg-Cato 138 kV line to accommodate growth of 138 kV demand.
- Timing: 2028
- Estimated Cost: $4,000,000.

→ MTEP Number: 50727

- Thompson Substation - Replace Thompson Substation's existing 345/138/13.75 KV, 300 MVA Autotransformer with 500 MVA transformer to accommodate additional growth on the Indianapolis 138 kV transmission network.
- Timing: 2029
- Estimated Cost: $15,000,000.

10.2 Future Considerations

AES Indiana will continue to monitor the following:

→ **Large Load Integration** – AES Indiana currently has minimal incremental capacity needs in the absence of new large loads. Any shortfalls can be addressed through demand-side strategies such as energy efficiency, demand response, and battery storage. However, adding a significant new load would require substantial new supply-side resources. To successfully integrate new customers, AES Indiana must carefully balance risk mitigation with strategic opportunities. Future regulatory proceedings will guide resource selection and rate design, with a focus on delivering cost-effective, reliable service while equitably safeguarding customer interests.

→ **Supply Chain Constraints –** AES Indiana is operating in a highly inflationary environment, where the cost of procuring new resources has risen sharply, even within the past year. Intense competition for equipment and project development has further strained supply chains. To remain responsive and competitive, AES Indiana may need to adopt more agile procurement strategies than previously required.

→ **MISO Seasonal Resource Adequacy Construct** – The Midcontinent Independent System Operator (MISO) approved the Direct Loss of Load (DLOL) Accreditation method in October 2024. At the time of this IRP filing, load-serving entities have not yet participated in the MISO capacity construct under the DLOL framework, leaving much to be learned about its practical implications. As AES Indiana gains experience in this evolving market structure, the company will need to adapt its planning—both in the near term and in future IRPs—to better reflect emerging realities.

10.3 Expectations for Future IRPs

170 IAC 4-7-4(16), 170 IAC 4-7-5(a)(9), and 170 IAC 4-7-8(c)(9)

AES Indiana plans to continue improving its IRP process and has identified the following items as potential improvements.

→ **Large load modeling**: As AES Indiana receives more detailed information from potential large load customers—such as data center developers, industrial facilities, or electrified transportation hubs—it will seek to incorporate these insights into IRP modeling. This includes refining assumptions around load size, timing, geographic location, and operational characteristics.

- → **Model alternative replacement resource options:** AES Indiana is particularly interested in exploring how large loads might actively participate in demand-side programs, such as targeted demand response or customized energy efficiency initiatives. Future IRPs may include scenario modeling that evaluates the effectiveness of these programs as alternatives to traditional supply-side investments. This approach could help reduce peak demand, defer infrastructure upgrades, and improve overall system flexibility.
- → **Include refinements made to the MISO capacity market**: AES Indiana will continue to monitor changes to MISO's capacity accreditation framework, including the implementation of the Direct Loss of Load (DLOL) methodology and other seasonal resource adequacy reforms. AES Indiana will look to enhance our internal forecasts for resource accreditation by considering the value of conducting an ELCC and a resource adequacy study separately from MISO to assess accreditation and reserve margins on a forward-looking basis, consistent with our IRP scenarios.
- → **Customer bill impacts:** While the IRP is not a rate design or cost allocation study, stakeholder feedback during the 2025 IRP highlighted strong interest in understanding how large load integration could affect customer rates. AES Indiana may consider including supplemental analysis or illustrative scenarios in future IRPs to explore potential bill impacts. Additional analysis could involve examining cost recovery mechanisms, rate design implications, and equity considerations across different customer classes.
- → **Enhanced reliability modeling:** To better capture the complexities of a changing grid, AES Indiana plans to enhance its reliability modeling capabilities. AES Indiana could include simulations of system performance under extreme weather conditions or unexpected load fluctuations.

10.4 Conclusion

The 2025 Integrated Resource Plan (IRP) marks a significant shift for AES Indiana. Rather than focusing on specific resource retirements or the implementation of new environmental policies, this IRP prioritized evaluating the potential integration of large new loads. Such additions could profoundly affect the utility's scale and operations. Throughout the planning process, AES Indiana actively assessed the implications of these changes and incorporated stakeholder feedback. The company remains committed to ongoing collaboration to ensure it continues to responsibly meet the evolving electricity needs of Central Indiana.

Section 11: Attachments and Rule Reference Table

Public attachments are available in Volumes 2 and 3 of AES Indiana's Public IRP Report. Confidential attachments and Information are available as part of AES Indiana's Confidential IRP Report.

11.1 List of Attachments

- Attachment 1-1 (AES Indiana's 2025 IRP Non-Technical Summary)
- Attachment 1-2 (AES Indiana's Public Advisory Meeting Presentations) **170 IAC 4-7-4(30) and 170 IAC 4-7-8(c)(5)**
- Attachment 5-1 (Test Year Hourly Loads (MW)) **170 IAC 4-7-4(12), 170 IAC 4-7-4(14), 170 IAC 4-7-5(a)(1), 170 IAC 4-7-5(a)(2), and 170 IAC 4-7-5(a)(10)**
- Attachment 5-2 (Itron Load Forecast Report) **170 IAC 4-7-4(3), 170 IAC 4-7-4(12) and 170 IAC 4-7-5(b)**
- Confidential Attachments 5-3a-f (EIA End Use Data) **170 IAC 4-7-4(12)**
- Attachment 5-4 (CMU Tech Paper) **170 IAC 4-7-4(12)**
- Confidential Attachment 5-5a (Moody's Q3 2024 - Base) **170 IAC 4-7-4(3), 170 IAC 4-7-4(12) and 170 IAC 4-7-5(b)**
- Confidential Attachment 5-5b (Moody's Q3 2024 - High) **170 IAC 4-7-4(3), 170 IAC 4-7-4(12) and 170 IAC 4-7-5(b)**
- Confidential Attachment 5-5c (Moody's Q3 2024 - Low) **170 IAC 4-7-4(3), 170 IAC 4-7-4(12) and 170 IAC 4-7-5(b)**
- Attachment 5-6 (Peak Forecast Drivers and Input Data) **170 IAC 4-7-4(3), 170 IAC 4-7-4(12), 170 IAC 4-7-5(a)(5), and 170 IAC 4-7-5(b)**
- Attachment 5-7 (AES Indiana's 20-Year Base Load Forecast) **170 IAC § 4-7-4(1), 170 IAC 4-7-4(3), 170 IAC 4-7-4(12), 170 IAC 4-7-5(a)(5), 170 IAC 4-7-5(a)(6), and 170 IAC 4-7-5(b)**
- Attachment 5-8 (Energy Forecast Drivers) **170 IAC 4-7-4(12), 170 IAC 4-7-5(a)(3), and 170 IAC 4-7-5(a)(5)**
- Confidential Attachment 6-1a (Capital Costs for model) **170 IAC 4-7-8(c)(7)**
- Confidential Attachment 6-1b (Capital Costs with source material) **170 IAC 4-7-8(c)(7)**
- Attachment 6-2a and Attachment 6-2b (Decrement Load Shapes Summary) **170 IAC 4-7-6(b)(2)(D) and 170 IAC 4- 7-6(b)(2)(E)**
- Attachment 6-3 (AES Indiana 2025 MPS) **170 IAC 4-7-4(15), 170 IAC 4-7-6(b)(2)(B), 170 IAC 4-7-6(b)(2)(D), and 170 IAC 4-7-6(b)(2)(E)**
- Confidential Attachment 6-4 (Avoided Costs) **170 IAC 4-7-4(29) and 170 IAC 4-7-8(c)(6)**
- Confidential Attachment 8-1 (Annual Generator Fuel Prices) **170 IAC 4-7-6(a)(3)**
- Attachment 8-2 Quanta Report

11.2 IURC Electric Utility Rule 7 Reference Table

170 IAC 4-7 (Readopted Filed Version September 12, 2025)

IAC Citation	Requirement	Location in AES Indiana 2025 IRP Report
Section 4: Integrated Resource Plan Contents		
170 IAC § 4-7-4(1)	At least a twenty (20) year future period for predicted or forecasted analyses.	Section 5.3 and Attachment 5-7
170 IAC § 4-7-4(2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Section 5.4
170 IAC § 4-7-4(3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Section 5.3 and Attachments 5-2, 5-5 through 5-7
170 IAC § 4-7-4(4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	Section 6.1
170 IAC § 4-7-4(5)	A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Section 8
170 IAC § 4-7-4(6)	A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	Sections 6.2, 6.3, and 6.4
170 IAC § 4-7-4(7)	The resource screening analysis and resource summary table required by section 7 of this rule.	Section 6.2
170 IAC § 4-7-4(8)	A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	Sections 8.1, 9.1, and 9.2.3
170 IAC § 4-7-4(9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Section 9.5
170 IAC § 4-7-4(10)	A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Section 10.1
170 IAC § 4-7-4(11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions;	Sections 5, 6, and 8
170 IAC § 4-7-4(12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include certain relevant data.	Attachments 5-1 through 5-8
170 IAC § 4-7-4(13)	A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated.	Section 5.1
170 IAC § 4-7-4(14)	The database in subdivision (13) may be developed using, but not limited to, the certain methods.	Attachment 5-1
170 IAC § 4-7-4(15)	A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	Sections 6.4.4 and 6-3
170 IAC § 4-7-4(16)	A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Sections 4.3, 4.6, 5.1, 6.5, and 10.3
170 IAC § 4-7-4(17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e) of this rule.	Section 1.5
170 IAC § 4-7-4(18)	A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Sections 4.2, 4.4, 4.6, and 5.5
170 IAC § 4-7-4(19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Sections 8.1 and 8.2
170 IAC § 4-7-4(20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	Section 2.3
170 IAC § 4-7-4(21)	A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Section 7.2.1
170 IAC § 4-7-4(22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 8

170 IAC § 4-7-4(23)	A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Sections 7 and 8.3
170 IAC § 4-7-4(24)	A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	Executive Summary, Sections 1.1, 9, and 10
170 IAC § 4-7-4(25)	A description and analysis of the utility's base case scenario, sometimes referred to as a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	Sections 8.2.1 and 9
170 IAC § 4-7-4(26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Sections 8.2.1, 8.4, 9.2.1, and 9.2.2
170 IAC § 4-7-4(27)	A brief description of the models, focusing on the utility's Indiana jurisdictional facilities, of the certain components of FERC Form 715.	Sections 3.2 and 3.3
170 IAC § 4-7-4(28)	A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Sections 5.3, 8, 9.3.6, and 9.3.7
170 IAC § 4-7-4(29)	An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	Section 6.4.6 and Confidential Attachment 6-4
170 IAC § 4-7-4(30)	A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.	Section 1.4 and Attachment 1-2
170 IAC § 4-7-4(31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 6
Section 5: Energy and Demand Forecasts		

170 IAC § 4-7-5(a)(1)	Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Attachment 5-1
170 IAC § 4-7-5(a)(2)	Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	Attachment 5-1
170 IAC § 4-7-5(a)(3)	Actual and weather normalized energy and demand levels.	Attachment 5-8
170 IAC § 4-7-5(a)(4)	A discussion of methods and processes used to weather normalize.	Section 5.3
170 IAC § 4-7-5(a)(5)	A minimum twenty (20) year period for peak demand and energy usage forecasts.	Attachments 5-6 through 5-8
170 IAC § 4-7-5(a)(6)	An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	Attachment 5-7
170 IAC § 4-7-5(a)(7)	A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 5.3
170 IAC § 4-7-5(a)(8)	Justification for the selected forecasting methodology.	Section 5.3
170 IAC § 4-7-5(a)(9)	A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	Section 10.3
170 IAC § 4-7-5(a)(10)	For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	Sections 5.1 and 5.4; Attachment 5-1
170 IAC § 4-7-5(b)	To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.	Section 5.3 and Attachments 5-2, and 5-5 through 5-7
170 IAC § 4-7-5(c)	In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 5.3
Section 6: Description of Available Resources		
170 IAC § 4-7-6(a)(1)	The net and gross dependable generating capacity of the system and each generating unit.	Section 6.1.1
170 IAC § 4-7-6(a)(2)	The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Sections 6.1, 9.4, and 10.1.1
170 IAC § 4-7-6(a)(3)	A fuel price forecast by generating unit.	Confidential Attachment 8-1
170 IAC § 4-7-6(a)(4)	The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units.	Section 7

170 IAC § 4-7-6(a)(5)	An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Section 3
170 IAC § 4-7-6(a)(6)	A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.	Sections 5.3 and 6.4
170 IAC § 4-7-6(b)(1)	Rate design as a resource in meeting future electric service requirements.	Section 6.5
170 IAC § 4-7-6(b)(2)(A)	A description of the potential demand-side resource, including its costs, characteristics, and parameters.	Section 6.4
170 IAC § 4-7-6(b)(2)(B)	The method by which the costs, characteristics, and other parameters of the demand-side resource are determined.	Section 6.4.6 and Attachment 6-3
170 IAC § 4-7-6(b)(2)(C)	The customer class or end-use, or both, affected by the demand-side resource.	Sections 6.4.2 and 6.4.3
170 IAC § 4-7-6(b)(2)(D)	Estimated annual and lifetime energy (kWh) and demand (kW) savings.	Attachments 6-2 and 6-3
170 IAC § 4-7-6(b)(2)(E)	The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements.	Attachments 6-2 and 6-3
170 IAC § 4-7-6(b)(2)(F)	Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	Sections 6.4.2 and 10.1.2
170 IAC § 4-7-6(b)(3)(A)	Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource.	Sections 6.2 and 6.3
170 IAC § 4-7-6(b)(3)(B)	A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Sections 2 and 3
170 IAC § 4-7-6(b)(3)(C)	A description of significant environmental effects.	Section 9.3.5
170 IAC § 4-7-6(b)(4)(A)	The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology.	Section 3
170 IAC § 4-7-6(b)(4)(B)	A description of the timing, types of expansion, and alternative options considered.	Section 3
170 IAC § 4-7-6(b)(4)(C)	The approximate cost of expected expansion and alteration of the transmission network.	Section 10.1.3
170 IAC § 4-7-6(b)(4)(D)	A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 3
170 IAC § 4-7-6(b)(4)(E)	A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Sections 2 and 3
Section 7: Selection of Resources		
Section 8: Resource Portfolios		
170 IAC § 4-7-8(a)	The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Sections 8 and 9
170 IAC § 4-7-8(b)(1)	An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(26) of this rule.	Section 9.2.2
170 IAC § 4-7-8(b)(2)	The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	Section 9

170 IAC § 4-7-8(b)(3)	The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2.2
170 IAC § 4-7-8(c)(1)	A description of the utility's preferred resource portfolio.	Section 9.4
170 IAC § 4-7-8(c)(2)	Identification of the standards of reliability.	Sections 9.3.4 and 9.4
170 IAC § 4-7-8(c)(3)	A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.5
170 IAC § 4-7-8(c)(4)	An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Sections 8 and 9
170 IAC § 4-7-8(c)(5)	An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost-effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Attachment 1-2 and Section 9.3
170 IAC § 4-7-8(c)(6)	An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Confidential Attachment 6-4
170 IAC § 4-7-8(c)(7)	A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Sections 9.3 and 9.4 and Confidential Attachments 6-1a and 6-1b
170 IAC § 4-7-8(c)(8)	A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Section 9
170 IAC § 4-7-8(c)(9)	Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 10.3
170 IAC § 4-7-8(c)(10)	A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors that would cause the forecasted relationship between supply and demand for electric service to be in error.	Sections 9.4 and 10
Section 9: Short Term Action Plan		
170 IAC § 4-7-9(a)	A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	Section 10
170 IAC § 4-7-9(b)	The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(10) of this rule, where the utility must take action or incur expenses during the three (3) year period.	Section 10

170 IAC § 4-7-9(c)(1)	A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.	Section 9
170 IAC § 4-7-9(c)(2)	Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10 and 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	Section 10.1.2
170 IAC § 4-7-9(c)(3)	The implementation schedule for the preferred resource portfolio.	Section 9.4 and 10
170 IAC § 4-7-9(c)(4)	A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	Section 10
170 IAC § 4-7-9(c)(5)	A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	Section 10