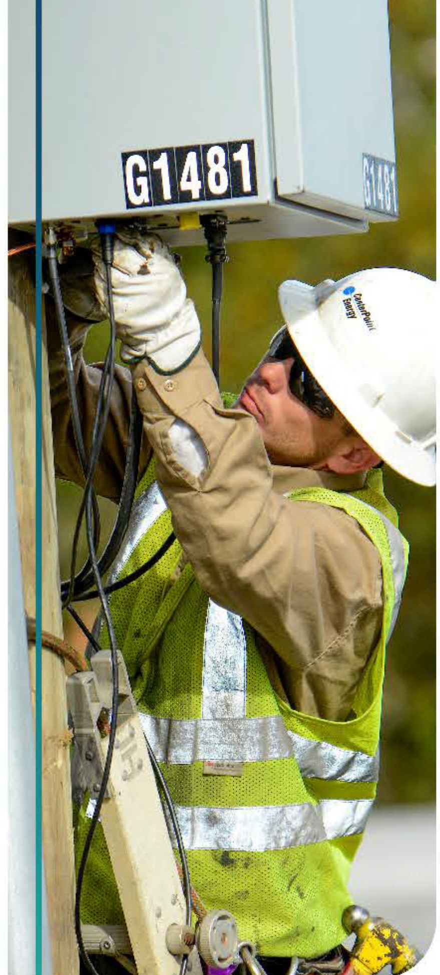

2025 Integrated Resource Plan

CenterPoint Energy

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Table of Contents

Table of Figures

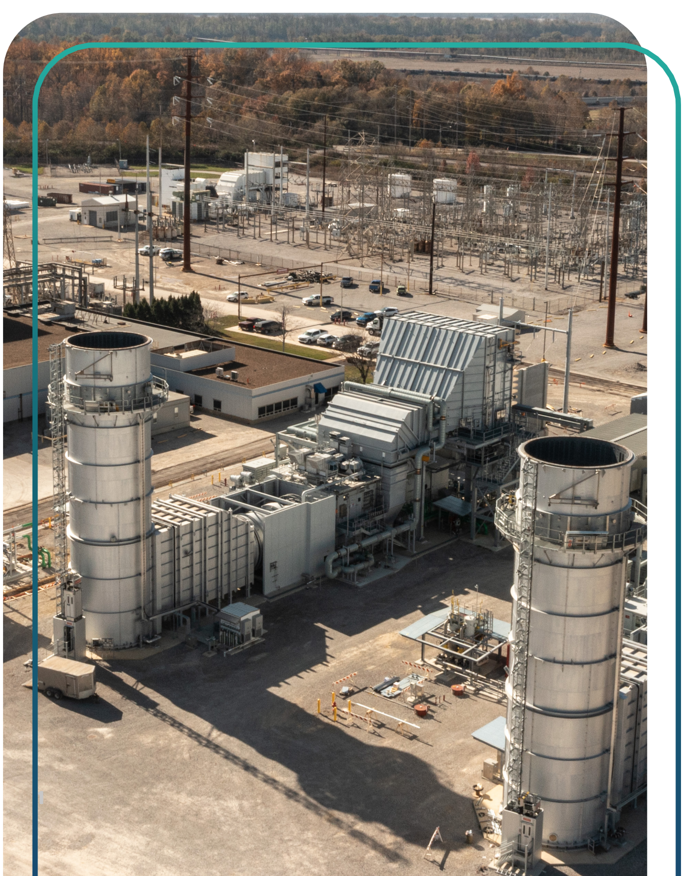
Executive Summary

(Non-Technical Summary)

Introduction

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South's ("CEI South"/"CEIS") 2025 Integrated Resource Plan ("IRP") is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has adhered to the requirements of the Indiana Utility Regulatory Commission ("IURC" or "Commission") and the guidance provided in the Commission's orders related to past Preferred Portfolios described in CEI South's previous IRPs both in the preparation of this IRP and the planning process that preceded the report.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. CEI South's 2022/2023 IRP identified a Preferred Portfolio that included a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with Demand Side Management ("DSM"), wind, and solar resources. CEI South began implementing the 2022/2023 IRP by filing two cases for which CEI South sought and received approval for (1) two signed purchase power agreements ("PPA") for wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project; and (2) approval for the 2025-2027 DSM Plan. Each of these filings were consistent with the 2022/2023 IRP, and as noted below, the IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered their cost relative to what could be acquired in the future, post elimination of Inflation Reduction Act ("IRA") tax incentives for wind and solar resources.

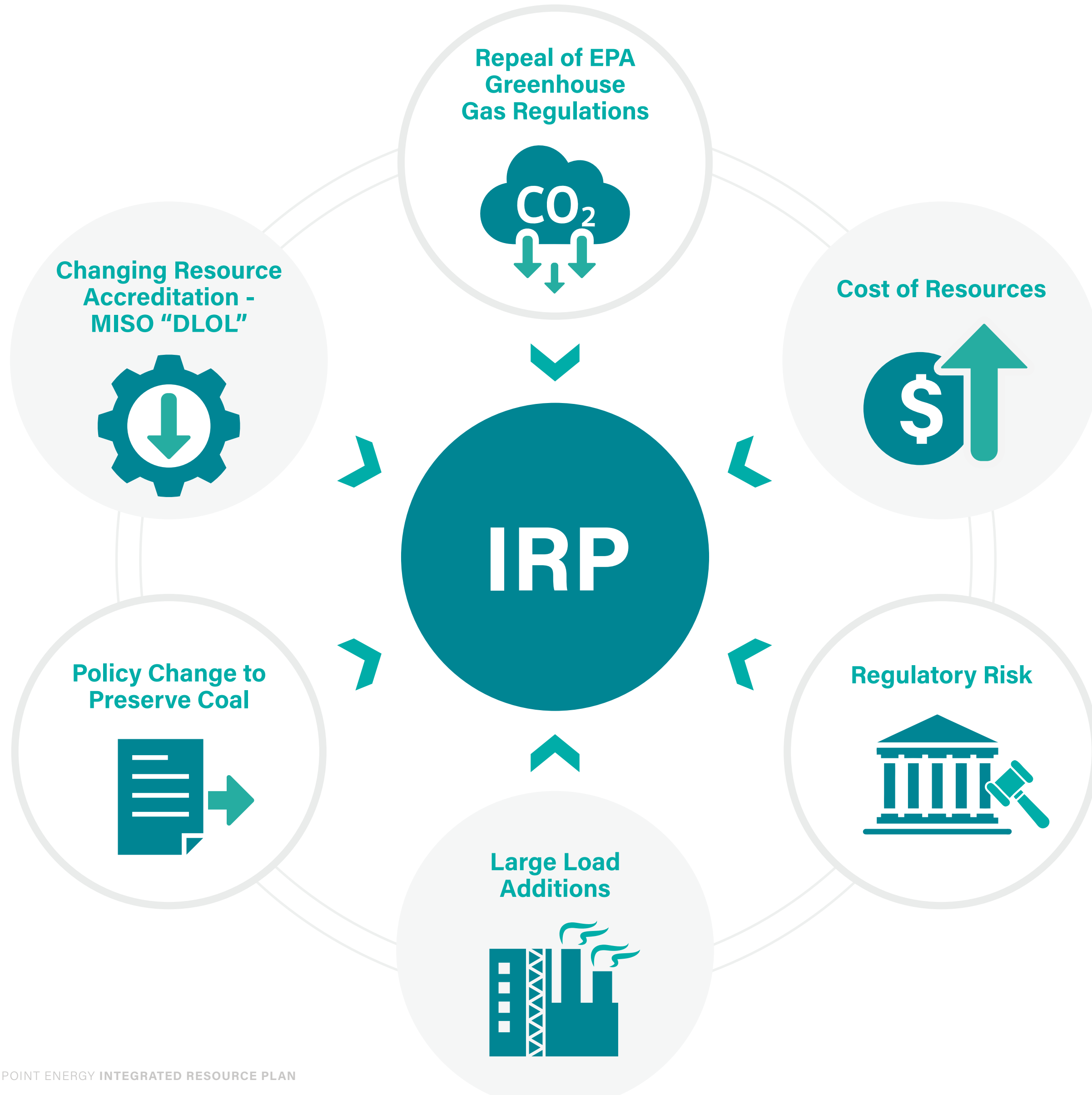


Now in 2025, during this time of unprecedented uncertainty across multiple fronts, the 2025 IRP analysis and its conclusions highlight the prudent decision for CEI South to reevaluate the timing of its generation fleet transition. Amid this time of evolving risk, and following our most recent rate case, there has been feedback from our customers and their advocates to keep bills more affordable. The IRP public meetings allowed us to listen to stakeholders and explain the uncertainty facing the industry.

Therefore, CEI South is reevaluating the timing of its transition to new or upgraded equipment in the near-term with a **focus toward rate stability and system reliability**.

The world looks very different than it did twelve months ago, when this IRP process began. The current pace and amount of change creates a variety of risks that, when weighed together, supports CEI South's decision to reevaluate the generation transition. The figure below summarizes current uncertainties.

Current Uncertainties



In 2023, CEI South filed its first electric base rate case in nearly 14 years. Ultimately, CEI South was approved to recover an additional $80 million from customers to continue to **safely and reliably deliver electricity** to their homes and businesses. While the energy transition CEI South set forth in prior IRPs was more affordable in the long run than continuing to operate its coal units, approximately 80% of the approved rate case increase was related to replacing A.B. Brown coal units 1 & 2 with 191 MW Posey Solar (~$385 million) and 460 MW natural gas combustion turbines (~$287 million). A.B. Brown's aging environmental equipment was required to be updated and replaced at a similar cost by 2024; this fact helps to illustrate the importance of strongly considering near-term affordability within the context of the IRP.

In this dynamic environment, CEI South has remained nimble to allow it to provide affordable and reliable service for its customers. Since the last IRPs were filed, there have been significant challenges in moving forward with key pieces of the last two IRPs' Preferred Portfolios. Several solar projects were terminated due to shifting market dynamics and substantial delays in commercial operation dates—one exceeding four years, with others averaging more than three. These market changes and delays drove project costs beyond the levels approved by the Commission and above what CEI South believed economical for its customers.

As such, the Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025, due to cost increases beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had upward pricing pressure. After years of negotiation and a re-evaluation of this project, CEI South opted, in this IRP, to abandon this project in an effort to avoid additional customer bill impact.

Also, in early 2025, CEI South announced that it paused the plan to convert F.B. Culley 3 to natural gas, to be re-evaluated in this IRP. Within this analysis, CEI South utilized more refined cost estimates and assumptions based on our preparation to convert the unit. This decision to pause the conversion was not taken lightly and was the direct result of near-term affordability concerns raised by the community, along with the current uncertainties listed in the previous figure.

Although the previous IRP projected long-term cost savings, CEI South estimates that implementing all proposed projects as planned would have resulted in a near-term bill increase of approximately $18 per month over the next few years. CEI South also heard some stakeholders express interest in re-evaluating the decision to convert F.B. Culley 3 within the context of the transparent IRP process, particularly given the near-term uncertainty driven by changes in the Federal and State administrations. CEI South's decision to reevaluate this path forward proved to be prudent. Under today's market conditions, (elimination of future Federal tax incentives for renewables, declining accreditation from MISO for renewables, increased price pressure on resources based on tariffs/ongoing supply chain issues), converting F.B. Culley 3 to natural gas by 2030 with renewables is projected to be the second highest cost portfolio evaluated, 17% higher than the lowest cost portfolio examined and 14% higher than the Preferred Portfolio.

CEI South began its 2025 IRP process in early 2025 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company's exploration included significant input and dialogue with stakeholders. While starting with our 2022/2023 IRP framework as a basis for the 2025 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to, the following:

- expanded sensitivity analysis (distributed solar incentive, large load additions, Demand Response term, etc.);
- increased collaboration with transmission and distribution planning;
- enhanced transmission analysis, unserved energy, capacity risk, etc.;
- inclusion of an expected data release schedule;
- five pillars focused score card with an expanded view of affordability; and
- refreshed IRP layout with enhanced description of analysis and results.

Over the last year, CEI South has participated in active discussions with several large load customers, and there was considerable stakeholder interest in understanding how CEI South would serve a large load addition. In order to maintain maximum flexibility, CEI South responded by including large load sensitivities and adding an alternate reference case to its analysis.

To maintain maximum flexibility and agility in these uncertain times, CEI South has selected both a **Preferred** and an **Alternate Preferred Portfolio**.

The Preferred Portfolio assumes the status quo for our territory. The Alternate Preferred Portfolio was developed should CEI South be in a position to provide power to a large load addition.

The alternate reference case maintains reference case market conditions but includes a potential large load addition that grows by 250 MWs per year, topping out at 1.5 GWs above CEI South's current retail load. This large load profile is indicative of ongoing discussions/negotiations with prospective customers. Potential large load customers require utilities to be able to serve their needs quickly, or they will take their economic development, supporting jobs and the tax base for the community, elsewhere.

CEI South plays a proactive role in **advancing economic development** across southwestern Indiana. By developing an Alternative Preferred Portfolio, the company enhances its agility **to better serve and support the region's evolving needs**.

With the need to provide reliable, stable, resilient, affordable, and sustainable energy to our customers, both Preferred Portfolios call for the conversion of A.B. Brown natural gas Combustion Turbine ("CT"), units 5 and 6, to an efficient Combined Cycle Gas Turbine ("CCGT"). The Preferred Portfolio provides customers with near and long-term rate stability and pushes this decision out to future IRPs until there is more clarity on the future while the Alternate Preferred Portfolio moves forward with the conversion by 2030. In either case, the decision on F.B. Culley 3's replacement will be decided in a future IRP. Both portfolios include the remaining solar and wind energy resources—secured prior to this IRP—at significantly lower costs compared to future renewable projects that may not benefit from near- to midterm Federal tax incentives. Both portfolios also include battery storage to replace CEI South's smallest and most inefficient coal unit, F.B. Culley 2. This allows time for CEI South to further evaluate the economics of this option relative to purchasing required capacity to maintain reliability. Finally, both include continued investment in energy efficiency and demand response resources.

The company has signed a contract with a demand response ("DR") aggregator for commercial and industrial DR by 2026. CEI South is also nearing the beginning of a pilot which was approved in its recent rate case to explore time-based rates. The Preferred Portfolio includes indicative DR amounts for IRP planning purposes.

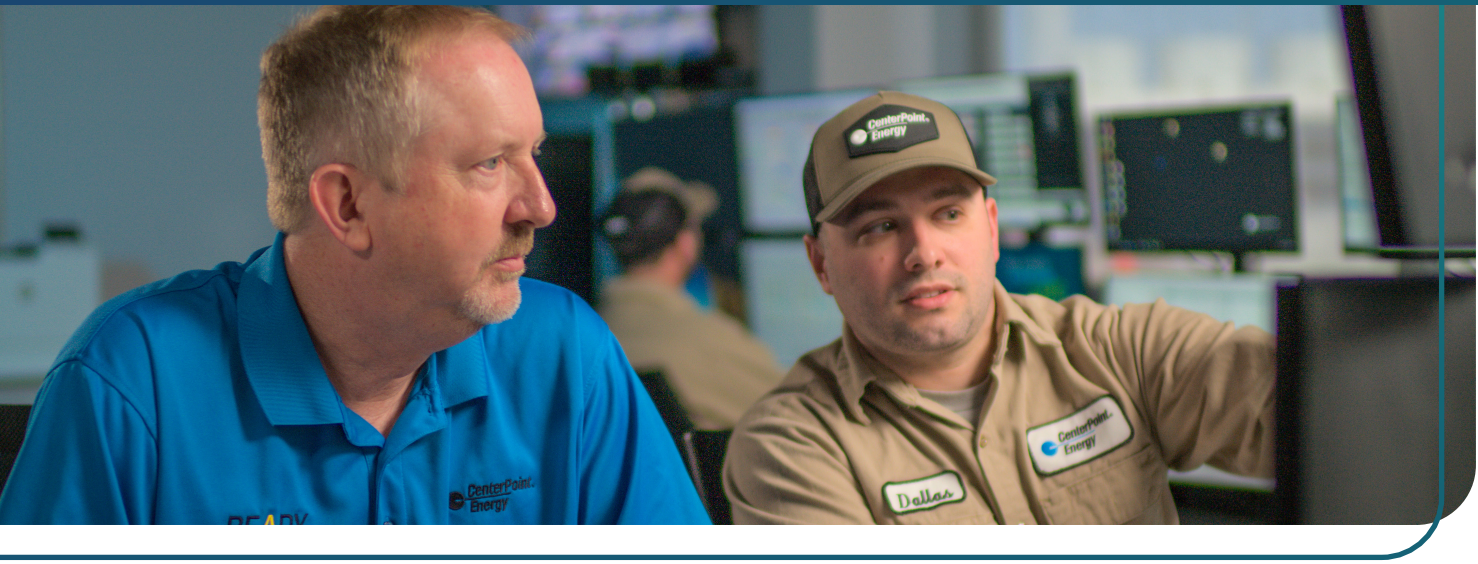
Preferred Portfolio

CEI South's Preferred Portfolio takes a more gradual approach to its generation transition, providing time for greater clarity amid today's unprecedented uncertainty. This approach also allows time for transmission system upgrades through CEI South's current TDSIC plan and the MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 projects, which support enhanced reliability and resilience.

The Preferred Portfolio provides for **maximum flexibility** to pivot should the future turn out differently than expected.

This is crucial in this current environment, where developers are less willing to share in cost risk which drives generation project costs higher for utility customers, with uncertainty around how much accreditation resources will receive from MISO to meet reliability requirements, or the direction of future greenhouse gas regulations.

In the short term, the plan maintains the F.B. Culley 2 interconnection, with possible 90 MW battery storage reuse and continues the demand side management programs. In the long-term and to be reevaluated in a future IRP, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit in 2034 to replace F.B. Culley 3 by 2035. The plan also calls for 50 MWs of battery storage in 2040 and 2045 to meet its planning reserve margin requirements.



Preferred Portfolio: **How Did We Get Here**

While current modeling suggests that replacement of F.B. Culley 3 coal with conversion of CEI South's two new CTs to a CCGT by 2030 could save customers money in the long run, locking in this option for CEI South's retail customers could increase bills in the near-term, increase risk, and reduce future flexibility. The conversion of these units would cost approximately $1 billion dollars or more and would likely be included in customer rates by 2030, costing customers up to $21 [1] more per month on average in the near term compared to the Preferred Portfolio which delays this decision. Affordability, one of the five pillars, is top of mind for CEI South and its customers following our recent rate case and has also been prominent within IRP stakeholder comments.

By slowing down the generation transition, customers should benefit from rate stability while preserving the flexibility—a critical capability in today's landscape—for CEI South to reevaluate F.B. Culley 3's fate in a future IRP. For example, in its previous IRP, CEI South had planned to convert F.B. Culley 3 to natural gas by 2027 with a continued renewables build out. However, just three years later, shifting external factors—such as reduced MISO accreditation for renewables, increased costs driven by market uncertainty, and diminished federal support following the rollback of key IRA tax incentives—have made this a more costly strategy relative to alternatives (14-17% higher).

Preferred Portfolio: **Overview**

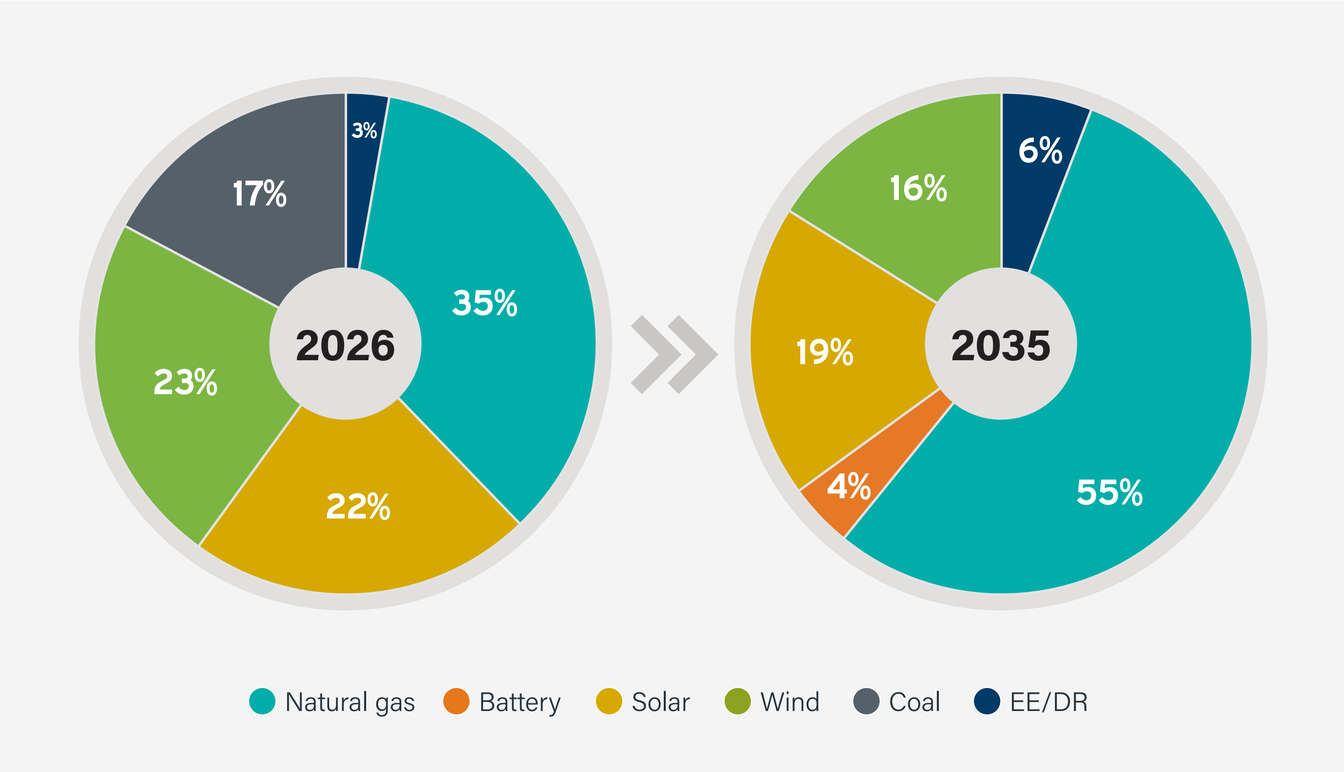
Between now and 2034, the Preferred Portfolio preserves the option to replace F.B. Culley 2 coal plant when it is suspended at the end of 2025 with a 90 MW battery storage unit by the end of 2028. CEI South will conduct another Request for Proposal ("RFP") to determine if the cost of this project has escalated from what was bid in the All-Source RFP and compare the cost to required capacity purchases. Based on the All-Source RFP, the cost of this battery is nearly identical to purchasing an equivalent amount of capacity on the market. Locking in capacity with a battery should help stabilize bills versus purchasing from a volatile capacity market that is expected to see rising prices as MISO's reserve margin continues to decline. It also helps maintain reliability with an on-system resource to help supply stored energy when it is needed most.

The Preferred Portfolio secures cost savings from wind and solar resources identified and acquired through previous IRPs, ahead of the repeal of IRA renewable energy tax incentives under the One Big Beautiful Bill Act ("OBBBA"). It also maintains operational flexibility by allowing F.B. Culley 3 to continue to run on coal, allowing time to reevaluate if conversion to natural gas or earlier retirement makes sense in a future IRP.

[1] *Not including expected offsetting sales revenues*

Preferred Portfolio: **Key Considerations**

CEI South's preferred resource plan reduces risk through continued diversification, lowers the cost to serve load over the next 20 years, and provides flexibility to evaluate and respond to future needs through subsequent IRPs.



The Preferred Portfolio has several advantages, including:

1. Among the least cost options, within **3% of the lowest cost portfolio** in the long term.
2. Provides near-term rate stability for **customer affordability** by delaying large capital investment.
3. Provides **affordable**, **reliable energy** with a well-balanced mix of **sustainable energy resources** and continued focus on demand side resources.
4. F.B. Culley 2 battery storage **enables avoidance of certain required capacity purchases**.

5. **Maximizes flexibility** to navigate unprecedented uncertainty; **minimizes risk**.

   - Delaying large capital investment also mitigates cost risk, as we live in very uncertain times. Current uncertainty is driving near-term price increases for various resources. It also helps reduce long-term price risk by allowing more time to better understand the direction of Environmental Protection Agency ("EPA") greenhouse gas regulations. Over the last 16 years environmental regulations have flexed and retracted with each administration. It is possible that in the next administration an aggressive greenhouse gas regulation could materialize which could throttle how much an efficient combined cycle gas unit may run, or a more stringent environmental regulatory requirement is finalized that would significantly increase operating costs for a fossil-fuel fired generation unit.

   - Provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. Maximum flexibility is important as demonstrated by the massive amount of change that has been experienced over the last decade. By proactively canceling high-cost renewable projects and securing affordable wind power purchase agreements, CEI South has taken decisive action to avoid increasing customer expenses. This forward-thinking strategy also strengthens CEI South's position ahead of MISO's upcoming accreditation reforms—reforms that are expected to significantly reduce the reliability value of certain resources, particularly solar. Additionally, pausing the conversion of F.B. Culley 3 and reevaluating under current market conditions preserves future flexibility at a lower near and long-term cost to our customers.

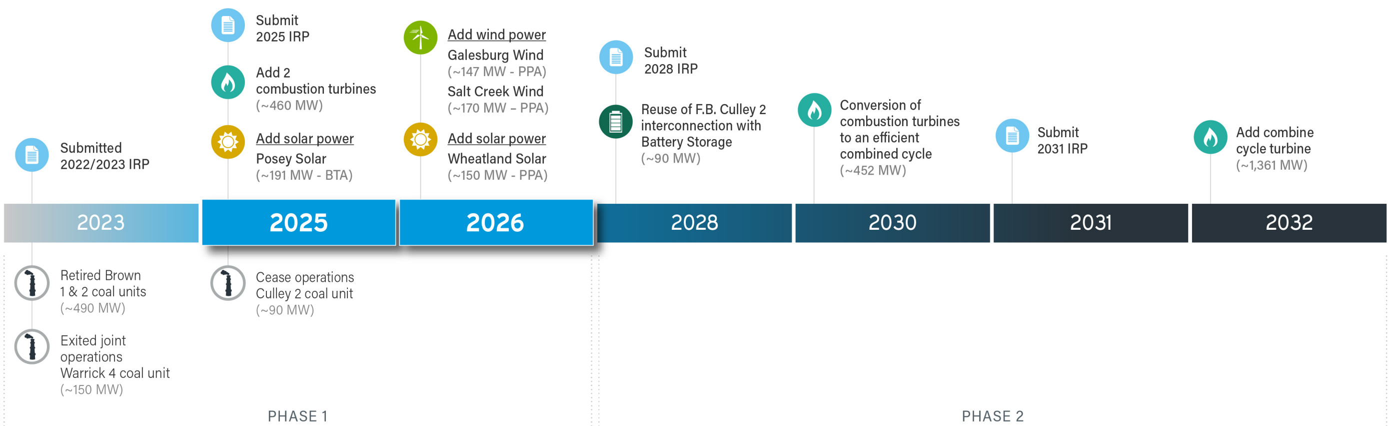
6. **Preserves tax base and jobs in Warrick County.** The replacement of F.B. Culley 2 with a battery storage system provides economic benefit to the community, whereas purchasing this needed capacity from the market does not. It is the equivalent of renting a home vs buying. Allowing F.B. Culley 3 to continue running in the near-term preserves tax base, benefiting the county while it continues to depreciate; it also maintains jobs associated with coal handling. Additionally, the facility uses Indiana-mined coal, preserving mining jobs and supporting the state's economy.

7. Maintains a base load generator on the east side of our system, providing **reliable**, **stable**, and **resilient power**.

   F.B. Culley Unit 3 continues to deliver essential voltage support to our community, providing valuable time for needed transmission expansion and offering flexibility as we await greater clarity on the future of nearby generation facilities that currently play a key role in grid stability.

8. Provides **flexibility** to serve a large load addition, should an **economic development** project materialize (See Alternate Preferred Portfolio).

Alternate Preferred Portfolio



The following Alternate Preferred Portfolio summary includes the process to identify the portfolio as well as an explanation of the planning process, all while focusing on CEI South's operations.

To maintain flexibility and stay nimble for potential economic development opportunities for southwestern Indiana, CEI South chose an **Alternate Preferred Portfolio** for a large load addition.

A large load addition scenario was created, starting at 250 MW and scaling up to 1,500 MWs in the early 2030s. Conversion of the new A.B. Brown CTs to a CCGT and F.B. Culley 2 battery storage become the most affordable options in the near-term to support the ramp. The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028 and continues demand side management programs.

Additionally, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit by 2030, continues F.B. Culley 3 on coal, and builds a large natural gas combined cycle unit by 2032 to support the large load addition. This build out is paired with near-term reliance on the market and aligns with system capabilities.

Alternate Preferred Portfolio: **How Did We Get Here**

Per stakeholder feedback, CEI South evaluated the potential for a large load addition that would scale over time. This scenario complements the multiple large load sensitivities conducted during the IRP and reflects insights gained from CEI South's ongoing conversations over the past several years with prospective customers across a range of industries. Commonly, CEI South is asked to determine how fast the system can be ready to accommodate a potential customer's business plan. Timelines have been compressed from what was considered normal in the past. These requests require CEI South's generation planning team to work closely with its transmission planning team. This scenario incorporates feedback from both teams, along with expert third party consultants to evaluate what is possible.

Alternate Preferred Portfolio: **Overview**

In the alternate reference case, all market conditions remain the same as reference case conditions, but load is increased by 250 MWs per year until the cumulative load reaches 1,500 MWs in the early 2030s. Load evaluations from prospective customers of this size were extremely uncommon for economic development projects in the past but are now approaching routine. CEI South selected the optimized, least cost model results as the Alternate Preferred Portfolio.

By including an Alternate Preferred Portfolio, CEI South is preserving necessary flexibility to quickly pivot, keeping southwestern Indiana competitive for economic development and growth. The Alternate Preferred Portfolio adds tax base and jobs to the community, not only from the prospective customer facility, but also from the infrastructure needed to support it. CEI South's analysis shows that generation near the site of the load is necessary to provide stability and avoid a large transmission outlay.

Alternate Preferred Portfolio: **Key Considerations**

The Alternate Preferred Portfolio:

- Preserves maximum future flexibility, keeping southwestern Indiana competitive for economic development and growth (Speed to market is important for most prospective customers),
- Adds tax base and jobs in our community, which helps all customers thrive,
- Aligns with Federal and State goals,
- Utilizes F.B. Culley 3 until replacement/conversion to natural gas is decided, and
- Adds efficient on-system base load generation for **reliability**, **stability** and **resilience**.

CEI South will continue to have ongoing conversations with prospective customers. At this point, no contract has been signed. As we prepare for this potential, CEI South will continue to evaluate possible timelines and costs necessary to serve. While the Alternate Preferred Portfolio provides a possible path, the resource mix to serve will be heavily influenced by a potential customer's need for low-cost power, along with other criteria important to the prospective customer. As such, CEI South modeled alternatives to aid in these conversations. CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations turn into negotiations/contracts.

CenterPoint Energy Overview

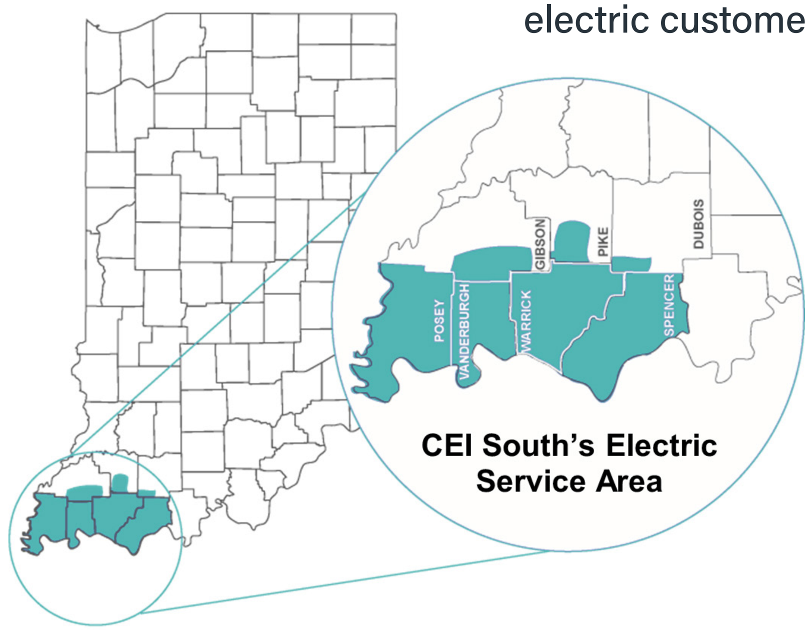
Provides energy delivery services to more than

150,000

electric customers

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in southwestern Indiana. In 2024, approximately 45% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers, and 25% were made to small commercial customers.

The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.

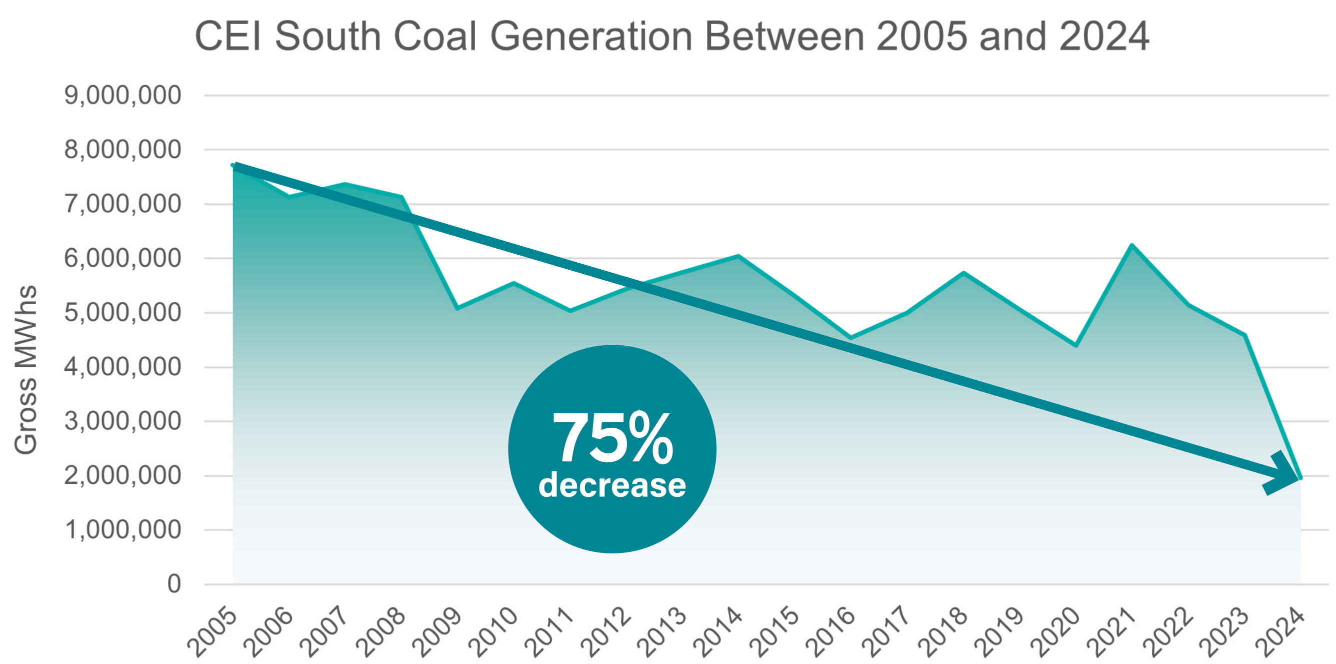


Unit [2]	Installed capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date/Expiration	Unit Age	Coal Unit Environmental Controls [3]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	230	Gas	2025	N/A	<1	
A.B. Brown 6	230	Gas	2025	N/A	<1	
Blackfoot	3	Renewable Gas	2009	N/A	16	
Fowler Ridge	50	Wind PPA	2010	2029	15	
Benton County	30	Wind PPA	2007	2028	18	
Galesburg	147	Wind PPA	2026	N/A	N/A	
Salt Creek	170	Wind PPA	2026	N/A	N/A	
Troy	50	Solar	2021	N/A	4	
Posey	191	Solar	2025	N/A	<1	
Wheatland	150	Solar PPA	2026	N/A	N/A	
Volkman Rd	2	DG Solar + battery	2018	N/A	7	
Oakhill	2	DG Solar	2018	N/A	7	
Post House	<1	DG Solar	2020	N/A	5	

[2] *CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.*

[3] *Both Coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_x"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("H_2S0_4").*

CEI South has largely moved away from coal, with the retirement of A.B. Brown units 1 & 2, exiting the joint operating agreement for Warrick 4, and the planned suspension of F.B. Culley 2 at the end of 2025.



These resources have been replaced with a diverse mix of wind, solar, energy efficiency, demand response, and gas resources. The current analysis demonstrates that customers receive a better balance of near-term and long-term affordability and reliability by continuing to evaluate the opportunity to replace CEI South's smallest and least efficient coal unit, F.B. Culley 2, with battery energy storage while deferring a decision on replacement of CEI South's last remaining coal unit that it operates, F.B. Culley 3, to a future IRP.

Integrated Resource Plan

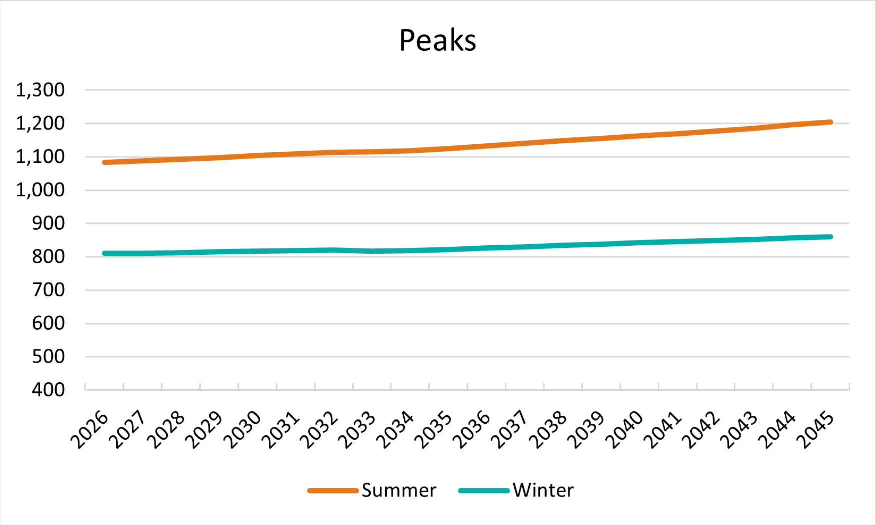
Every three years CEI South submits an IRP to the IURC as required. The IRP describes the analysis process used to evaluate the optimal mix of generation, storage, energy efficiency, and demand response resources (resource portfolio) to meet customers' needs for reliable, resilient, stable, affordable, and environmentally sustainable power ("the five pillars") over the next 20 years. The IRP helps set the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

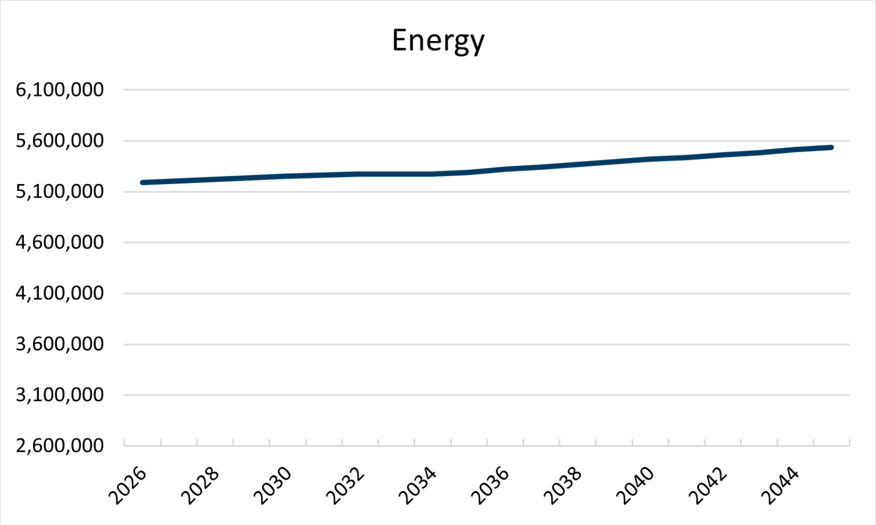
CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, trade associations and environmental advocacy groups. CEI South placed considerable emphasis on the five pillars, rate stability, risk, and resource diversity. The IRP process continues to increase in complexity as MISO continues to implement resource accreditation reforms to maintain reliability of the system that includes increased levels of renewable resources, battery energy storage, and natural gas resources to replace existing coal resources.

Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Demand is typically measured in Megawatts ("MW"), and energy is typically measured in Megawatt hours ("MWh"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation, demand side (energy efficiency and demand response), and storage resources available to meet expected customers' seasonal peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement ("PRMR") for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO member, CEI South must comply with MISO's evolving rules to maintain reliability.

CEI South must meet customer demand in all hours of the year. This has become more challenging, as the regional resource mix changes towards intermittent (variable) renewable generation. MISO functions as the regional transmission operator for 15 midwestern and southern states, including Indiana (also parts of Canada). MISO evaluates how changes in the future resource mix impact reliability. Recently, they have received FERC approval to update the way resources are accredited to the Direct Loss of Load ("DLOL") methodology beginning in 2028, which is projected to have a substantial impact on solar accreditation in the summer and winter when load is at its highest. CEI South has accounted for this change and worked with stakeholders to develop a reasonable accreditation projection given the best available information. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability.





CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles.

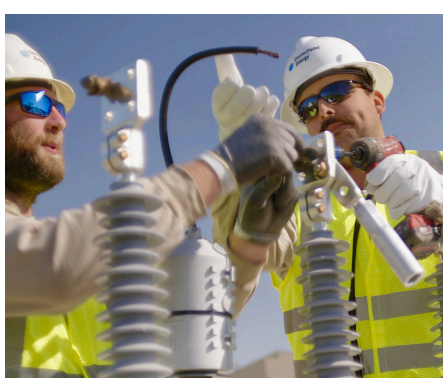
Overall, customer energy and summer peak demand, excluding energy efficiency, are expected to grow by **0.5% per year.** Winter peak demand grows at a slightly slower pace of **0.3% per year.**

Resource Options Considered

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 95 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, bio-mass thermal, demand response, and wind. These project bids provided up-to-date, market-based information to inform the analysis. Additionally, CEI South utilized other information sources for long-term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing F.B. Culley 3 coal unit, conversion of F.B. Culley 3 coal unit to natural gas, various other natural gas resources, conversion of A.B. Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries.

Every IRP is a snapshot in time producing a direction based on the best-known information. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the accelerated sunset of wind and solar tax incentives from the IRA with the passage of OBBBA, the rise of Artificial Intelligence ("AI") data centers and onshoring of industrial manufacturing driving unprecedented load growth, state and federal executive orders to maintain existing resources, continued increased costs for renewables projects, new technologies, and rapid changes in the MISO market to adapt and help enhance reliability.

- Battery storage
- Coal
- Energy efficiency/ Demand response
- Hydro electric
- Natural gas
- Nuclear
- Wind and solar

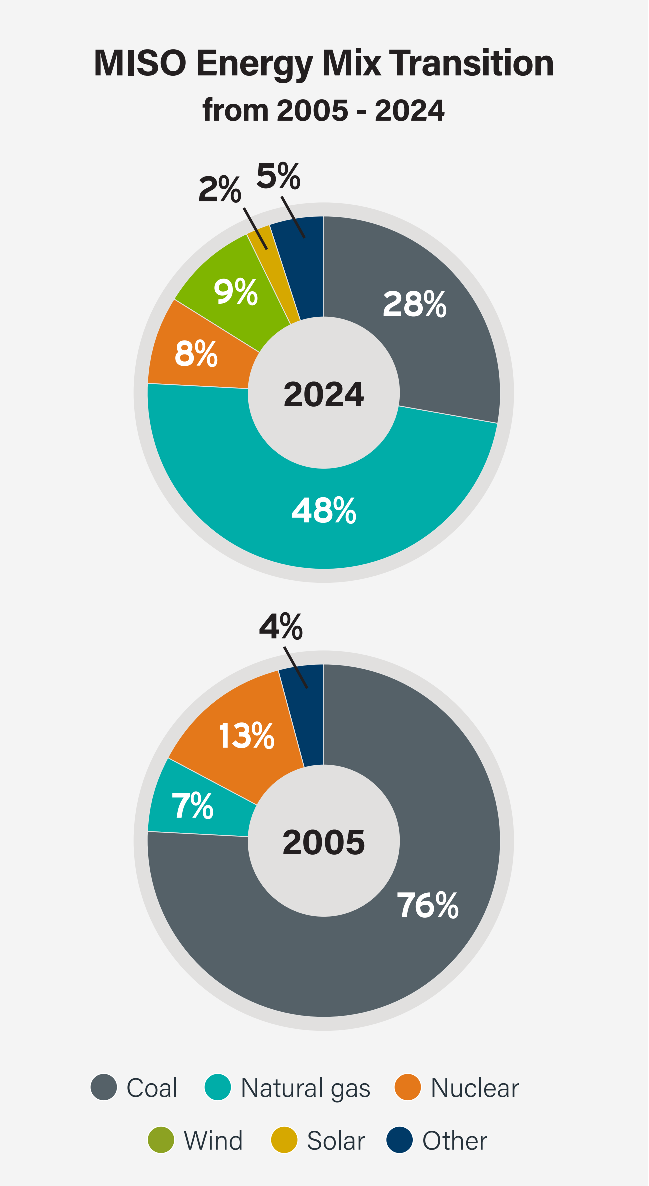


INDUSTRY TRANSITION

The transition to intermittent renewable resources within MISO has continued over the last several years, although at a slower pace. Until the pandemic, renewables costs declined rapidly due to improvements in technology and government incentives. This largely stalled and began an upward climb. Wind and solar resources continue to face increasing price pressure, interconnection delays, and decreasing accreditation from MISO. With the passage of OBBBA, renewable resource tax incentives sunset more quickly than under the IRA placing more pressure on renewable resources.

This comes as load growth to serve data centers supporting AI is projected to ramp very quickly over the next several years. Each data center can use enough energy to power a mid-sized city, and they require power twenty-four hours a day, necessitating dispatchable resources. Additionally, President Trump has made tariffs a core part of his second term. These tariffs are designed to incentivize manufacturing to come back to the United States, thus providing new economic development opportunities, particularly with industries related to national security. For example, his administration has focused on the steel and aluminum industries, which also bring the potential for extremely large loads.

To respond to this challenge, the federal government is working to slash regulations and maintain incentives for baseload (24x7 power) nuclear resources. Additionally, the state of Indiana has responded with incentives for these prospective customers and also with economic development incentives aimed at spurring development in small modular nuclear resources that can provide power intense data centers and large industrial facilities with zero carbon emitting resources, the first of which, in Indiana, is likely to come on-line in the early to mid-2030s.



In the near-term, gas resources are seeing unprecedented demand from utilities to meet increasing near-term load obligations. Installed capacity of wind and solar resources is expected to continue to increase within the MISO footprint, although more slowly than even a few years ago. Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation in 2005, used primarily to meet the needs during peak demand conditions, to approximately 48% of total generation in 2024.[4] Meanwhile, coal has declined but still supplies a little more than a quarter of the energy need within MISO, followed by wind at 9%, nuclear at 8%, and solar at 2%.

[4] *MISO 2024 State of the Market Report, Potomac Economics, June 2025, page 6 https://cdn.misoenergy.org/2021 State of the Market Report625295.pdf https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf*

The move toward renewables and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to consistently compete on short term marginal price with renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with EPA regulations. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has also driven unit retirements.

While coal has been declining, it remains an important source of power for our grid, particularly as this capacity-rich resource has seen an uptick in market capacity revenues. Additionally, President Trump has written executive orders aimed at supporting the coal industry in an attempt to preserve remaining plants. With these market changes, coupled with increasing costs for renewable and gas resources, we are more likely to see some coal units remain online longer than they otherwise would have.

CHANGING MARKET RULES TO HELP ENSURE RELIABILITY

MISO recognizes the major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have overproduction (more energy produced than is needed at the time) and other periods will have low-to-no renewable energy production, requiring dispatchable resources to meet real-time demand for power. MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future.

Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing mix of resources, there is an increased importance of ensuring that adequate attributes are available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained, MISO implemented a seasonal resource adequacy construct beginning with the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand. As part of the seasonal construct, thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("EFORd") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources continues to be challenged as MISO received approval to further revise the accreditation approach in 2028 with the introduction of DLOL methodology. The move to DLOL is expected to most affect renewable resources, particularly solar. For example, solar resources were expected to provide about 25% or more of their total installed capacity to cover MISO's reliability requirement. This is expected to drop over time to approximately 5% or below in the summer, CEI South's tightest season. The practical effect is that more capacity will be needed when fully implemented.

Also, MISO continues to study how demand response resources will be accredited. To date, these reforms have provided more certainty that demand response will be there when called upon; however, there is a much higher bar than in the recent past for industrial customers to participate with annual testing and required faster response times to remain a participant in these programs. MISO reforms will continue as reserve margins continue to tighten and increasingly include intermittent renewable resources that make it more difficult to maintain acceptable voltage and thermal limits on the grid than traditional, dispatchable resources.

CEI South has accounted for these changes by incorporating the seasonal construct and DLOL accreditation approach into the Encompass model, and the portfolios in this analysis provide sufficient resources to meet its MISO obligations in all four seasons with limited capacity purchases. Additionally, CEI South analyzed the thermal limits of equipment along with the voltage and reactive power needs of the system for various portfolio options and identified mitigations.

BATTERY STORAGE AND TRANSMISSION RESOURCES

To support greater reliance on intermittent renewable resources, utilities are increasingly considering the opportunity to add battery storage to resource portfolios to help provide availability and flexibility. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature. In fact, 2024 All-Source RFP bids for battery storage to replace F.B. Culley 2 as a potential CEI South resource were cost effective for the first time.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining the reliability of the transmission system. CEI South has experience operating a 1 MW battery designed to capture energy from an adjacent solar project. This pilot project has provided information that will be helpful in moving forward with a much larger project. The 90 MW battery will be available to discharge energy for four hours and will be available for energy arbitrage and meeting peak load conditions.

Uncertainty/Risk

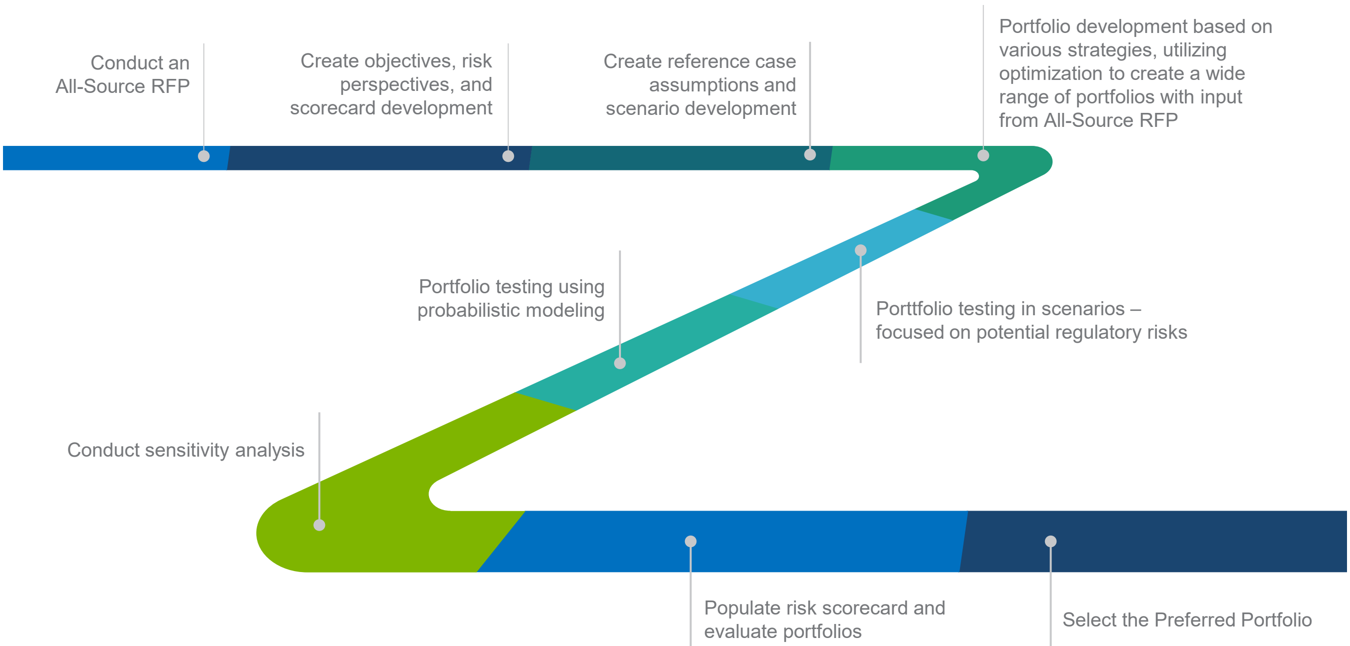
As demonstrated over the past few years, the future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the preferred resource portfolio mix of generation and demand side resources to serve customer energy needs over a wide range of possible future states. CEI South worked with 1898 & Co. to perform two sets of modeling to contribute to the risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes. Additionally, the risk analysis included sensitivities and qualitative judgement.

Analysis

CEI South's analysis included a step-by-step process to identify the Preferred Portfolio. The graphic below summarizes the major steps which included the following:

1. Conducted an **All-Source RFP** to better understand resource cost and availability.
2. Worked with stakeholders to develop a **scorecard** as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Worked with stakeholders to develop a wide range of **future states**, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Worked with stakeholders to develop a wide range of **portfolios** for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Conducted a **risk analysis,** including deterministic and probabilistic modeling with sensitivity analysis.
6. Utilized the **quantitative scorecard measures** and **judgment** to select the Preferred Portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).

Analysis Process



Stakeholder Process

As in the last IRP, each of the last three stakeholder meetings began with stakeholder feedback. CEI South reviewed requests/comments from the prior stakeholder meeting and provided feedback. Suggestions were taken, and in instances where suggestions were not acted upon, CEI South explained why not. Notes for each meeting were included in question-and-answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (IRP@CenterPointEnergy.com) and with phone calls/meetings in between each public stakeholder meeting by request.

While maintaining the virtual option to participate, CEI South thought it was important to continue face-to-face meetings. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to southwestern Indiana or did not wish to participate in person. Dates and topics covered are listed below.

CEI South held a series of technical meetings with stakeholder groups willing to sign a Non-Disclosure Agreement ("NDA") and participate in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. These meetings, along with a data release schedule, helped keep technical stakeholders informed throughout the process and provided an opportunity to engage with CEI South in a way that is not always possible during public stakeholder meetings.

CEI South also incorporated feedback from the Director's report on its previous IRP, along with insights from the annual Contemporary Issues Conference hosted by the IURC. The 2025 Conference topics proved especially timely - highlighting considerations for large load coordination and planning. Discussions underscored the importance of flexibility and preparation to account for the impacts of large load within our planning process. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.

3/19/25 Agenda

1

- 2025 IRP Process, Objectives & Metrics
- All-Source RFP Results
- MISO Update
- Environmental Compliance Update
- Large Load Sensitivity
- Draft Sales & Demand Forecast
- Resource Options
- Commodity Inputs
- Scenario Development
- Stakeholder Questions/Feedback

5/14/25 Agenda

2

- Process Recap
- Stakeholder Feedback
- Final Scenarios
- Supply-Side Resources
- DSM Market Potential Study
- Sales & Demand Scenario Forecast
- Probablistic Modeling Approach & Assumptions
- Scenario Forecasts
- Portfolio Development Method
- Draft Reference Case
- Stakeholder Questions/Feedback

9/11/25 Agenda

3

- Stakeholder Feedback
- Revisions to Scenarios
- DSM Market Potential Study – Initial Results
- Portfolio Development Methodology and Draft Scenario Optimization Results Draft Deterministic Portfolio Results
- Portfolios Discussion
- Scenario and Probabilistic Modeling Update
- Early Sensitivity Results

10/23/25 Agenda

4

- Stakeholder Feedback
- Preferred Portfolio
- Risk Analysis Modeling and Portfolios
- Portfolio Characteristics and Considerations
- Risk Analysis Scorecard
- Alternate Reference Case
- Sensitivity Results

Based on this stakeholder engagement, CEI South made fundamental changes to the analysis in real-time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the Preferred Portfolio were updated through this process. CEI South held meetings with interested stakeholders willing to sign an NDA ahead of and in between public stakeholder meetings. This, along with providing modeling inputs, helped to allow for a more productive dialogue throughout the process. CEI South appreciates the time and attention provided by each group that participated in this process.

CEI South utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios, including the addition of a possible future, the alternate high regulatory scenario. CEI South updated the scorecard to measure risks in each of the five pillars (Affordability, Environmental Sustainability, Reliability, Resiliency, Stability) with a separate section for other market risks. Per the Director's report, CEI South added the 5th percentile of Net Present Value Revenue Requirements ("NPVRR"). CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding an affordability metric (electric energy burden) that illustrated the 5-10 year incremental impact to energy burden (incremental residential bill impact in 2030 and 2035 divided by Vanderburgh County median household income). This measure highlights near to mid-term price pressure that customers may face for each portfolio. Additionally, CEI South added measures for Dynamic VAR Support ("MVAR") and Short Circuit Ratio ("SCR") from its updated transmission reliability analysis. CEI South also added SOx and NOx emissions and capacity sales/purchases to the scorecard. Adjustments were also made to modeling inputs and assumptions based on direct stakeholder feedback. The following table shows key stakeholder requests made during the process and CEI South's response.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scorecard	Under the Environmental Sustainability Objective: Remove CO_2 intensity, keep CO2-e tons	CEI South believes that there is value in keeping CO_2 intensity, as well as CO_2-e metrics. CO_2 intensity allows the reader to compare CO_2 levels across scenarios.
Scorecard	Include metrics for SOx and NOx	CEI South has added metrics that includes combined tons of SOx and NOx.
Scorecard	Under the Affordability Objective: consider adding an energy burden calculation	CEI South proposes to add electric energy burden, defined as the 5-Year [5] residential rate impact as of July 1, 2025 divided by the Vanderburgh County Median Household Income.
Resource Options	Are the Demand Response proposals subject to discussion/change with Demand Side Management (DSM) Oversight Board	CEI South continues to discuss Demand Response with members of the DSM Oversight Board
Resource Options	Is CEI South considering what the resource mix could be if a resource incentive (updated EDG rate) is included in the IRP?	CEI South is conducting a sensitivity considering a $500 per kW incentive for Distributed Generation solar resource.
Load Forecast	Provide a breakout of peaks by customer class	See graph in 3/19/2025 Stakeholder meeting notes posted at www.centerpointenergy.com/irp
Load Forecast	Why is CEI South using historical rather than forecast temperature, e.g., Purdue University temperature forecast?	CEI South used a linear projection of temperature based on historical data; it is not significantly different from the Purdue University study for the IRP period.
Load Forecast	Requested CEI South to revisit the estimated 12,000 miles for EVs used in the forecast	Itron EV assumption for reference forecast. The 12,000 miles per year for EVs was revised to 9,500 miles per year. This revision is noted in the 5/14/2025 Stakeholder meeting slides

[5] *CEI South ultimately added a 5 and 10 year incremental energy burden per stakeholder request.*

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Load Forecast	Does the EV charging profile used for CEI South's load forecast account for remote work at home?	The NREL tool, EVI-Pro, documentation does not specifically state any assumptions regarding work from home. The "EVHome" charging profile on slide 61 of the 3/19/2025 stakeholder slides includes some level of charging between 11am-2pm. (slides posted at www.centerpointenergy.com/irp)
Load Forecast	Does CenterPoint have plans to electrify its fleet?	CenterPoint does have plans to electrify its fleet - please see the following link https://sustainability.centerpointenergy.com/energy-transition-goals/fleet/
Commodity Inputs	Does the natural gas forecast assume increased drilling under the current administration?	At this time, CEI South is uncertain how the current administration's policies will affect natural gas prices. Our vendors consider multiple factors when developing commodity forecasts. Utilizing a consensus forecast is an approach CEI South has taken in previous IRPs. These various perspectives allow us to capture the diversity in opinions for future market prices.
Generation Timeline	Regarding Salt Creek Wind, is this project going to service CenterPoint customers or just provide power to the MISO grid as accredited power? If it's going to be service to CenterPoint customers, what kind of transmission loss are you expecting since the power is coming from Iowa?	Please see Witness Swanson's public testimony in Cause No. 46218.
Objectives & Draft Measures	Will the electric energy burden separate electrically heated homes from gas heated homes, or will those be combined in the aggregate?	We'll look at both the customers with electrically heated homes and the customers with gas heated homes. However, either view will show the same relative difference among portfolios.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scenarios	Suggest adding an option where load stays at base. In this scenario, generation capital costs could still be high.	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Scenarios	When looking between high regulatory and alternative high regulatory, can you potentially do the same with low regulatory (an alternative low regulatory with low load)?	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Supply-Side Resource	Can CEIS incorporate real coal price offers made to CenterPoint. The uncertainty variable is not the mining cost as much as the demand.	Due to the confidential and competitive nature of CEIS's contractual coal price this was discussed during the 8/20/2025 Tech to Tech meeting
Supply-Side Resource	How many bids did CEIS receive for storage?	There were 17 standalone storage bids. The 2024 All-Source RFP results were shared during the 3/19/2025 Stakeholder meeting. The presentation is available here: CenterPointEnergy.com/IRP.
Supply-Side Resource	Is CEIS accounting for all costs and benefits, including considerations such as health costs? Will these other benefits be incorporated into the IRP?	Health costs are captured within EPA regulations that are included in the applicable scenarios.
Supply-Side Resource	Has CEIS considered the water pressure nuclear option, such as the Westinghouse AP1000?	The general nuclear option included in the Tech Assessment is representative of a variety of future nuclear options. If you have information regarding technology performance or costs that you would like to see in the model, please email IRP@CenterPointEnergy.com

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
MPS	For the battery storage program, without large enough penetration of batteries, it's hard for benefits to outweigh the costs. Could we look at a battery storage equipment incentive?	We performed cost-effectiveness screening using a range of incentives and adoption rates. In all scenarios the Utility Cost Test ratio was less than 1, which is not cost-effective. Results are included in today's (9/11/2025) Stakeholder meeting.
MPS	For EVs, are customers bringing their own device for the charger? Would customers have to use specific technology to participate?	We are assuming that the customer would supply their own charger, and CenterPoint would provide an incentive to join the program, as well as an annual participation incentive. A managed charging program would require some sort of network connection, which could include Wi-Fi, cellular, or a wired connection. A specific technology would not be required, as control could happen through the charger or telematics through the EVs
MPS	Some DR measures like batteries and water heaters can be used for other grid services (ancillary services, resilience) – how are these benefits being considered in developing levelized costs and/or accounted for in the IRP? Is it possible to treat these like T&D benefits and reduce from the cost side?	When performing cost-effectiveness screening, the benefits include the avoided energy, capacity, and T&D. Resilience and ancillary services have not been a benefit of Demand Response captured in the IRP analysis.
Model Inputs	Is CEIS going to include Scope 3 emissions?	Scope 3 emissions are outside the scope of the IRP as it's related to emissions of the end-user and separate from electricity generation.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Model Inputs	Since CEIS is considering nuclear, does CEIS want to run a stochastic process for uranium?	We are currently using publicly available data sources for uranium pricing forecasts. Uranium pricing is not expected to be a major differentiator in the portfolio risk assessment when compared with other cost drivers. Given this, we do not anticipate that running a stochastic process for uranium will materially change the outcomes of the analysis.
Model Inputs	Is CEIS planning to use the MISO published 2025/2026 indicative DLOL results for the solar and wind accreditation assumptions?	We have revised the accreditation values to interpolate between the first season of DLOL and 2035. Providing a smoother shift in accreditation. Revised Solar and Wind capacity accreditation forecasts are included in the 9/11/2025 presentation's Appendix.
Model Inputs	Recommendation to analyze two DER resource portfolios, Distributed Capacity Procurement (DCP) and Virtual Power Plants (VPPs) in CEI South's 2025 IRP	CEI South's evaluated demand response programs that align with the intent of both DCP and VPP programs as well as a DG Solar incentive during the IRP process. Updates on the evaluations are included in today's (9/11/2025) Stakeholder meeting.
Modeling	Scenario Portfolios – Explain why manual modifications applied to scenario portfolios to align with the Reference Case load	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Scenario Portfolios – Request to re-run the capacity expansion simulation instead of the production cost simulation	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Modeling	Scenario Portfolios – Request to share documentation illustrating manual modifications made to the scenario portfolios	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Build Limits – Request for CEI South to consider running scenarios with relaxed limits	CEI South ran a simulation and chose to relax limits to allow more resources to be selected within the capacity expansion model.
Modeling	Consider a study with FB Culley 3 retiring in 2030	Given the unprecedented amount of uncertainty at this time and future transmission upgrades that will help with system reliability and resilience, it would not be prudent to consider retirement prior to 2031/2032, as is being considered within this IRP.
Affordability Measure	Request for energy burden calculation	CEI South will make the energy burden workpaper available to technical stakeholders with a signed NDA.
Rates	Request to provide guidance on bill itemization	Please see the CenterPoint website, where is shows an explanation of the bills. https://www.centerpointenergy.com/en-us/residential/customer-service/resource-hub/understanding-your-bill?sa=in

Meeting materials for each meeting can be found at **CenterPointEnergy.com/IRP** and in Technical Appendix Attachment 4.2 Stakeholder Materials.

Next Steps

CEI South's flexible plan provides two paths forward, depending on what the future holds. If a large load customer agreement is not made prior to the next IRP in 2028, CEI South will move forward with the Preferred Portfolio. With this path, there are a few items that must be done in the short-term action plan.

First, CEI South will continue to implement the generation transition that was identified in prior IRPs. CEI South is currently pursuing three renewable projects that are scheduled to be online in 2026: 147 MW Galesburg Wind (approved PPA), 150 MW Wheatland Solar (approved PPA), and 170 MW Salt Creek Wind (approved PPA). These projects will continue to diversify CEI South's generation mix.

Secondly, CEI South will conduct two RFPs to determine current pricing for capacity and battery storage for replacement of F.B. Culley 2 interconnection in the next three years. Having run past its useful life, F.B. Culley unit 2 (coal) is slated for suspension at the end of this year. FERC rules allow for replacement of the interconnection within 3 years of suspension. CEI South will continue to evaluate the proper path forward with consideration for Indiana's five pillars. Should CEI South choose to reutilize the interconnection, it will seek approval in a Certificate of Public Convenience and Necessity ("CPCN") before the IURC and modify its Attachment Y with MISO to an Attachment X.

Third, CEI South will file for a DSM plan, consistent with the results of the Preferred Portfolio.

Finally, CEI South will continue to engage with economic development opportunities to help strengthen southwestern Indiana. Should a large load addition materialize, CEI South would diligently work to implement its Alternate Preferred Portfolio that would potentially require multiple CPCNs and approval of a contract with the IURC. These filings will be consistent with the Preferred Portfolio paths. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the Preferred Portfolio.

CEI South's plan must be flexible, as several items are not certain at this time, including but not limited to: MISO DLOL, EPA greenhouse gas regulations, cost of resources, policy change, the potential for large load additions, and regulatory risk.

Integrated Resource Planning

Chapter 1

1.1. Integrated Resource Planning

CEI South takes integrated resource planning very seriously. The Integrated Resource Plan ("IRP") is used as a guide for how CEI South will serve existing and future customers over the next 20 years in a reliable, affordable, stable, resilient, and environmentally sustainable manner. The integrated resource plan sets the direction for future generation and Demand Side Management ("DSM") options; however, future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

CEI South is required to submit its IRP to the IURC every three years and last submitted it in 2023 with a plan to transition its generation fleet away from a majority reliance on coal to a portfolio of renewable generation, supported by a diverse set of natural gas generation resources. Since that time two new quick start, fast ramping natural gas combustion turbines and the Posey Solar project have come on-line, while the conversion of F.B. Culley 3 to natural gas was paused for re-evaluation within this IRP, and several renewable projects were canceled due to increasing cost.

With a focus on stakeholder input, CEI South began the 2025 IRP process by gathering feedback from stakeholders on the last IRP and the Director's Report for the 2022/2023 IRP. Additionally, CEI South worked closely with IRP stakeholders throughout the process, including multiple tech-to-tech discussions and information sharing between public stakeholder meetings, as discussed in Section 8.6 Public Advisory Process.

Although the future remains uncertain; several factors have set the stage for the 2025 analysis. After many decades of stagnant growth, reindustrialization and the Artificial Intelligence ("AI") race has changed the trajectory and will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power in the near-term. Renewable resources have been slow to come online, many of which are not projected to come on-line at all due to higher than projected interconnection costs, delays in the MISO queue, tariffs, declining accreditation from MISO, changes to state and federal policy, the proposed repeal of EPA greenhouse gas regulation, and the passage of the One Big Beautiful Bill Act ("OBBBA") that accelerated the sunset of IRA tax credits to wind and solar resources.

Despite considerable uncertainty throughout the IRP development, CEI South has remained agile in navigating evolving risk, including but not limited to incorporation of stakeholder feedback on methodology, modeling, and assumptions, adding two additional scenarios per stakeholder feedback, and updating originally proposed scenario assumptions in near real time to account for proposed changes in EPA regulation. This necessitated requesting and receiving approval for an extension to submit the IRP on or before December 5, 2025.

1.1.1. Indiana's Five Pillars

On April 20, 2023, House Enrolled Act 1007 was signed into law by Governor Eric J. Holcomb. Indiana incorporated the Five Pillars of Indiana energy policy into state law in Indiana Code 8-1-20.6, with an effective date of July 1, 2023. The law states that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider the following attributes: reliability, resiliency, stability, affordability, and environmental sustainability. The Indiana Utility Regulatory Commission adopted General Administrative Order ("GAO") 2023-04, which was inclusive of IRPs.

The Five Pillars are Reliability, Resiliency, Stability, Affordability, and Environmental Sustainability. Each has been considered equally within this IRP and are defined below:

Figure 1-1 – Five Pillars

To better account for the five pillars, CEI South structured its portfolio scorecard, a tool to help evaluate risk and tradeoffs, by aligning measures with each of the pillars to aid in the selection of a Preferred Portfolio. While affordability often takes center stage, each pillar is essential in shaping a comprehensive energy strategy. Under the lens of the five pillars, CEI South included the following scorecard updates:

- Incorporated a view into near-term affordability with the inclusion of an energy burden analysis. This complements the traditional long-term affordability measures;
- Conducted a more in-depth evaluation of reliability, resilience, and system stability in this IRP through a dedicated transmission analysis, which informed the development of additional scorecard measures; and
- Enhanced its view into environmental sustainability by adding additional air measures into the scorecard.

1.1.2. State of the World

Over the last year and a half, there has been unprecedented change that directly effects resource planning, including but not limited to:

- Updates to how resources will be accredited to meet reliability requirements,
- Updates to greenhouse gas regulations from the EPA,
- Escalating costs for various resources,
- Policy changes on the state and federal levels,
- Increasing load for the first time in decades, and
- Change in the regulatory environment.

Changes like these have escalated in recent years. Utilities typically face one or two major challenges per planning cycle. These risks demand careful mitigation to ensure the selected resource portfolio remains flexible and capable of adapting to an uncertain future. CEI South and other utilities across the country are required to make long-term planning decisions in a way that mitigates all of the risks that present themselves. This cycle is particularly challenging with at least 6 major unresolved issues, each of which presents a different risk.

1.1.3. Generation Transition (MISO)

MISO is in the midst of a significant transformation in how it plans for and accredits capacity, reflecting both the rapid transition of the generation fleet and the increasing level of system risk. In 2023, MISO shifted from an annual construct to a Seasonal Accredited Capacity (“SAC”) framework, requiring utilities to demonstrate sufficient accredited resources in all four seasons. This shift recognizes that reliability risks no longer occur only in the summer season. Growing penetrations of solar and wind, shoulder-season maintenance outages, and evolving demand patterns have increased exposure to non-summer season peaks. Seasonal planning introduces more precision into capacity accreditation and compels utilities to build portfolios resilient to reliability challenges year-round.

Looking ahead, MISO is also preparing to replace its current accreditation methods with a more probabilistic approach based on Direct Loss of Load (“DLOL”) modeling. This proposed framework, expected to take effect in the 2028/2029 Planning Year, will assign capacity value to resources based on their performance in avoiding loss-of-load events rather than static assumptions. It builds upon traditional Loss of Load Expectation (“LOLE”) analysis but offers finer granularity by considering not only the probability of shortfall but also the contribution of each resource type in mitigating it. For utilities, the transition means that intermittent resources such as wind and solar will receive capacity credit more directly tied to their effective reliability contribution, while fast-start and dispatchable resources may become even more valuable.

Alongside the move to seasonal and probabilistic accreditation, MISO is also advancing changes in how the Planning Resource Auction (“PRA”) clears capacity through the introduction of the Reliability Based Demand Curve (“RBDC”). The RBDC links capacity prices directly to reliability outcomes by steepening the demand curve as the system approaches shortfall conditions. In effect, it values incremental capacity more highly when the system is at risk, sending stronger price signals for new entry and retention of resources that support reliability. By aligning market prices more closely with the reliability value of capacity, RBDC is designed to help ensure sufficient investment while avoiding undue reliance on emergency procedures.

At the same time, the generation interconnection queue is undergoing substantial reform. With thousands of megawatts of renewable and storage projects proposed, MISO has adopted new cluster-based study processes, standardized timelines, and cost allocation reforms to accelerate development while maintaining fairness and reliability. These reforms are intended to reduce backlog, improve transparency, and align new resource development with regional transmission expansion.

Taken together, the seasonal construct, evolving probabilistic accreditation, implementation of RBDC, and queue reforms reflect the broader generation transition underway in MISO. The system is moving away from static, one-size-fits-all capacity rules toward more dynamic, risk-informed approaches that account for the realities of a rapidly changing resource mix. For utilities like CEI South, these changes require close monitoring and integration into planning processes to ensure that portfolios not only meet today’s requirements but remain reliable and compliant under tomorrow’s market rules.

1.1.4. Political and Regulatory Environment

Since the last IRP, significant shifts have occurred at both the federal and state levels, including the election of Donald J. Trump as President of the United States and Mike Braun as Governor of Indiana.

President Trump immediately rescinded executive orders issued during the Biden administration and replaced them with new directives aligning with his administration’s policy agenda. Speaking in broad strokes, these changes were intended to unleash American energy dominance, paving the way to keep existing fossil generation on-line and to put in place barriers to renewable energy generation.

Along with the flurry of executive orders, President Trump signed the OBBBA into law. With his signature, this bill set into motion the core of President Trump’s tax and spend agenda. It has had far reaching impacts throughout the energy industry and integrated resource planning. The law rolls back tax incentives for those that purchase electric vehicles, which could have an effect on load projections in the long-term. Additionally, the bill rapidly phases out Inflation Reduction Act (“IRA”) tax incentives for wind and solar resources, while nuclear and battery resource provisions from the IRA were largely preserved.

President Trump has also brought in a new era of tariffs in an effort to bring back lost manufacturing by leveling the playing field with foreign countries. While tariffs could bring more load back to the system in the long run, near-term uncertainty and inflation have had the effect of raising costs for new generating resources, often built with materials sourced from all over the world.

Finally, President Trump has worked to appoint those that will promote his agenda through government agencies. These agencies have made shifts that must be accounted for within the IRP, most notably, the potential roll-back of EPA greenhouse gas regulations could ease restrictions on fossil-fueled dispatchable resources needed to support the administration’s desire for dominance in Artificial Intelligence.

Although Governor Braun’s election has not yet resulted in policy shifts as sweeping as those at the federal level, several notable developments in Indiana warrant attention. Governor Braun is also supportive of maintaining existing fossil fuel generation to support economic development opportunities, and he is a strong proponent of building small modular nuclear reactors in Indiana by the early 2030’s. To carry out his energy agenda to ensure affordable and reliable power for current residents and economic development opportunities, Governor Braun named Suzanne Jaworowski Secretary of Energy and Natural Resources. In her position, she oversees the Indiana Department of

Environmental Management, the Indiana Regulatory Commission, the Office of Utility Consumer Counselor, and several other agencies.

In August, Governor Braun named long-time utility consumer advocate Abby Gray as Utility Consumer Counselor and directed her find ways to lower bills for Hoosiers. Additionally, Governor Braun will soon be appointing three new Commissioners to the IURC.

1.1.5. Environmental Regulations

In June of 2025, EPA proposed to rescind greenhouse gas limits for new and reconstructed gas turbines and existing and modified coal fired generating units under Clean Air Act Sections 111(b) and (d). As an alternative, the proposal would withdraw a previous determination that carbon capture and storage is commercially available and cost effective to reduce greenhouse gas emissions. This change had a major effect on modeling assumptions within the current IRP, as the ultimate finalization of either option would rescind the drivers for retirement of uncontrolled (for CO_2) units by 2032. While this is still a proposal, the proposal is an action in response to the Administration's Executive Order 14154, "Unleashing American Energy", which directs EPA to identify rules that "impose an undue burden" on domestic energy resources. CEI South believes that the current requirements applicable to GHG's under 111(b) and (d) will not be the most likely future regulatory scenario and therefore updated its Reference Case. Ultimately, the proposed rule revisions will be litigated, and a new proposal could come from a future administration. CEI South developed scenarios to account for these future regulatory uncertainties and potential boundary conditions.

1.1.6. Large Loads

With the rise of AI data centers and onshoring of industry, the country is facing rapid electric growth that has not been seen in decades, if ever. Depending on the project, these loads can start large and scale very quickly, some of which grow to be larger than a mid-sized city such as Evansville, IN. CEI South has fielded many economic development inquires over the last two years, several of which fit this mold.

As part of this IRP, CEI South initially planned a large load sensitivity that evaluated possible build outs based on conversations. However, stakeholders were understandably very interested in this topic given the implications for our system. In response, CEI South agreed it was prudent to develop a separate scenario to address this realistic possibility. As a result, CEI South built an Alternate Reference Case to evaluate the best path forward should an agreement be reached with a potential large load addition.

1.1.7. CenterPoint Energy Rate Case and Community Engagement

In December of 2023, CEI South filed its first rate case in 14 years. Ultimately, a settlement was approved, increasing revenues by $80 million dollars. The increase was approved to be phased in over a year between February 2025 and March 2026, with the largest increase coming in the summer of 2025 as the Posey solar plant and the first of the two new combustion gas turbines (A.B. Brown unit 6) came on-line. 80% of the requested increase was associated with these generation units, including unit 5, which came online in August. Customer affordability was a key issue throughout the case with our customers and their advocates. With affordability top of mind, CEI South worked to evaluate the bill impact of various portfolios in the near to mid-term, as well as evaluating the long-term affordability of each portfolio. Ultimately, near to mid-term affordability proved to be one of the key differentiators in the selection of the 2025 Preferred Portfolio.

To strengthen communication with customers, CEI South hosted an initial round of Community Connect sessions across its service territory. These events offered customers the opportunity to engage directly with CenterPoint employees about key investments aimed at improving system reliability and enhancing bill transparency. Subject matter experts were on hand to answer questions and address concerns related to CEI South's long-term planning and the IRP Preferred Portfolio. Dates and times of the Community Connect sessions are listed in the table below.

Figure 1-2 – Community Connect Sessions

DATE	TIME	LOCATION
Thursday, 11/6	4 - 7 p.m.	**South Spencer High School** 1142 N. County Road 275 W., Rockport, IN
Saturday, 11/8	9 a.m. - noon	**Vanderburgh County 4H Fairgrounds** 201 E. Boonville-New Harmony Road, Evansville, IN
Wednesday, 11/12	4 - 7 p.m.	**Mount Vernon Junior High School** 701 Tile Factory Road, Mount Vernon, IN
Thursday, 11/13	4 - 7 p.m.	**CK Newsome Community Center** 100 E. Walnut Street #1, Evansville, IN
Saturday, 11/15	9 a.m. - noon	**Ohio Township Phoenix Event Center** 3433 Libbert Road, Newburgh, IN

1.1.8. CEI South Current Generation Portfolio

The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.

Figure 1-3 – CEI South Generating Units

Unit[6]	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date / Expiration	Unit Age	Coal Unit Environmental Controls[7]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	232	Gas	2025	N/A	<1	
A.B. Brown 6	232	Gas	2025	N/A	<1	
Blackfoot	3	Renewable Gas	2009	N/A	16	
Fowler Ridge	50	Wind PPA	2010	2029	15	
Benton County	30	Wind PPA	2007	2028	18	
Galesburg	147	Wind PPA	2025	N/A	N/A	
Salt Creek	170	Wind PPA	2025	N/A	N/A	
Troy	50	Solar	2021	N/A	4	
Posey	191	Solar	2025	N/A	<1	
Wheatland	150	Solar PPA	2026	N/A	N/A	
Volkman Rd	2	DG Solar + Battery	2018	N/A	7	
Oakhill	2	DG Solar	2018	N/A	7	
Post House	<1	DG Solar	2020	N/A	5	

1.1.9. Status on Implementing Prior IRP (Retirements and Additions)

Since the last IRP filing, CEI South has encountered significant challenges in moving forward with key pieces of the last two IRP Preferred Portfolios. First, several renewable projects have been terminated due to market dynamics that caused prices to escalate beyond what the Commission approved and beyond where CEI South believed to be affordable for its customers. The Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025 due to cost increases

[6] CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

[7] Both Coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_X"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("$H2S0_4$").

beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had similar upward pricing pressure; after years of negotiation and a re-evaluation of this project in this IRP, CEI South opted to walk away from this project in an effort to keep customer rates as affordable as possible.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. At that time, the Preferred Portfolio in CEI South's previous 2022/2023 IRP concluded that a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with DSM, wind, and solar resources was the optimal path forward. CEI South began implementing this 2022/2023 IRP by filing two cases seeking approval for (1) signed purchase power agreements ("PPA") for two wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project and (2) approval for the 2025-2027 DSM Plan. Each of these filings were consistent with the 2022/2023 IRP, and as noted below, this IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered the cost of these renewable resources relative to what could be acquired in the future, post elimination of IRA tax incentives for wind and solar resources.

In preparation for retirement, CEI South submitted an Attachment Y to MISO to suspend operations of its smallest, least efficient coal unit, F.B. Culley 2. This unit is slated for suspension at the end of 2025. A key decision in this IRP was to determine how to replace this unit and whether or not to preserve the existing interconnection to the grid. CEI South will have approximately three years to replace the unit, preserving the interconnection. Options that were available and evaluated were small gas units or battery storage.

1.1.10. Culley 3 Conversion

In the last IRP, CEI South selected a Preferred Portfolio that converted F.B. Culley 3, a 270 MW coal plant, to natural gas by 2027. Given the inputs and likely potential future at that time, this was a competitive option. In light of growing change and uncertainty, CEI South chose to pause its conversion plans and opted not to pursue a Certificate of Public Convenience and Necessity from the Indiana Utility Regulatory Commission at this time. CEI South chose to re-evaluate the F.B. Culley conversion with renewables within this IRP. While the F.B. Culley coal-to-gas conversion may become a viable option in the future, current analysis indicates it is not projected to be cost-effective. As detailed later in this IRP, a conversion paired with renewables is projected to be approximately 14% more expensive than the Preferred Portfolio.

Resource Planning Process

Chapter 2

2.1. Planning Structure

CEI South's IRP was developed using a structured, data-driven planning process that incorporates real-world operating conditions, market signals, stakeholder input, and long-range policy and technology expectations. While uncertainty remains a fundamental characteristic of long-term planning, CEI South's objective is to develop a portfolio that is resilient across a wide range of plausible futures while maintaining affordability, reliability, environmental sustainability, stability, resilience, and operational feasibility. The IRP process is organized around five major planning steps:

1) **Real-World Inputs and Modeling Foundations** – Establishing accurate load forecasts, technology costs, demand-side potential, resource data, and fuel assumptions, supported by market solicitations and expert consultation.
2) **Development of Resource Strategies and Planning Scenarios** – Structuring candidate resource strategies, evaluating transmission deliverability, and modeling a range of policy and demand futures.
3) **Planning Priorities and Guiding Principles** – Defining the core decision-making values that shape portfolio evaluation, supported by stakeholder perspectives and long-term CEI South objectives.
4) **Comprehensive Portfolio Development & Testing** – Using a suite of planning tools to simulate long-term portfolio performance, test sensitivities, and assess operational and financial tradeoffs.
5) **Portfolio Evaluation** – Comparing portfolios using a structured framework aligned with CEI South's long-term planning priorities.

The remainder of this section outlines each step in more detail, highlighting the analytical foundation that supports the Preferred Portfolio selection later in the IRP.

2.2. Real-World Inputs and Modeling Foundations

In Q2 2024, CenterPoint launched an open All-Source Request for Proposals ("RFP") (*Technical Appendix Attachment 2.1 2024 All-Source Request for Proposal*) to solicit capacity and energy resource options from the market, including specifically requesting options to replace the F.B. Culley 2 generator and reuse the existing transmission interconnection. This broad solicitation was essential for capturing current, technology-specific costs and operational characteristics. The 2024 All Source RFP yielded a diverse set of project proposals, including renewables, storage, thermal resources, and demand-side offerings. These responses informed both near-term procurement strategies and were also translated into representative long-term modeling inputs.

In addition to the All-Source RFP, CEI South worked with 1898 & Co. to conduct a detailed technology assessment (*Technical Appendix Attachment 2.2 2025 Technology Assessment Summary (Confidential)*) to support the evaluation of a wide range of

resources and to supplement the All-Source RFP. Resource-specific cost assumptions were based on a combination of historical operations data and forward-looking financial models. Fixed and variable O&M, depreciation, book life, and capital recovery factors were incorporated to reflect the true economic impact of maintaining or replacing legacy assets. Each resource type was reviewed for cost, performance, availability, and operational viability, which informed the resources that were included in modeling.
CEI South continued its long-standing partnership with Itron, a recognized leader in energy forecasting to produce 20-year energy and demand forecasts. The resulting load forecasts incorporated recent trends in fleet electrification, trended weather, customer behavior, economic growth, customer-owned rooftop solar, and appliance efficiency. This foundational input was used across all planning scenarios.

To evaluate the long-term potential of customer energy savings, CEI South worked with GDS Associates to conduct a comprehensive Market Potential Study (*Technical Appendix Attachment 3.6 2025 DSM Market Potential Study*) focused on demand-side management ("DSM"). The study assessed achievable impacts across the planning horizon by analyzing customer segmentation, end-use technologies, cost-effectiveness, and adoption potential. These results were integrated into portfolio modeling to reflect Demand Response ("DR") and Energy Efficiency ("EE") as resource options on a consistent and comparable basis with supply-side alternatives.

Supporting these major studies was a rigorous data development effort. CEI South used publicly available datasets, averaged confidential vendor information in order to incorporate multiple perspectives and to allow for public viewing, and internal data to populate a robust suite of assumptions. For instance, CEI South utilized industry forecasts for natural gas and other fuels, including NYMEX futures, third-party consultant projections, and public sources such as the EIA. These assumptions were scenario-specific and reflected differing regulatory environments and market conditions.

This work helped ensure that resource modeling was grounded in transparent and realistic expectations.

2.3. Development of Resource Strategies and Planning Scenarios

CEI South developed a set of generation strategies to reflect plausible pathways based on CEI South's existing fleet, known constraints, and evolving regulatory and market dynamics. For example, as part of evaluating the future of existing coal-fired generation, CEI South modeled multiple resource conversion and replacement strategies to test how the system responds to retirement timing, capacity shortfalls, and differing replacement technology mixes.

These deterministic generation strategies served as a foundational planning step, representing different strategic postures. Some explored early retirement and rapid decarbonization; others maintained legacy assets longer to evaluate affordability or for fuel diversity. To support this process, CEI South created several fixed resource configurations, including storage options, new gas replacements, continuation of existing resources, conversion of existing resources, and renewable heavy alternative, to observe how the capacity expansion model responded. These “what-if” inputs were used to test the system’s flexibility and better understand which technologies filled capacity gaps most effectively under different assumptions.

In parallel, CEI South initiated a transmission study (*Technical Appendix Attachment 2.3 Transmission Study (Confidential)*) to examine the deliverability, reliability, and cost implications of these generation strategies. This was a critical component of planning, as the viability of new generation, especially renewable resources, often depends on transmission availability and local system limitations. Transmission constraints, upgrade needs, and regional challenges were modeled alongside generation expansion to ensure that the resulting portfolios were not only economically viable but also physically feasible on an electric transmission basis. The findings from the transmission study were used to:

- Identify system constraints that might require upgrades or lead to curtailment risks;
- Quantify the cost of transmission upgrades associated with portfolio sensitivities; and
- Refine resource strategies and modeling assumptions where needed.

This integration of transmission and generation modeling ensured that resource portfolios were built on a technically sound foundation, which attempts to minimize the risk of stranded assets or overlooked system limitations.

2.4. Stakeholder Engagement

Stakeholder engagement is a cornerstone of integrated resource planning, as input is shared on all portions of the analysis. The stakeholder process functions as a collaborative forum – providing a diverse range of views with multiple opportunities to provide input on the assumptions, inputs, and methodologies to inform CEI South’s IRP development. Over the past twelve months, CEI South has provided many engagement opportunities to a diverse audience of CEI South customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials. Throughout the 2025 IRP, stakeholders were encouraged to engage and participate in the development of the Integrated Resource Plan. Engagement opportunities included public meetings, technical meetings, and direct communication channels via CEI South's IRP website and the IRP-specific email address, irp@centerpointenergy.com. CEI South has also engaged in written correspondence in response to data requests from several stakeholders.

CEI South hosted four public meetings in Evansville, Indiana – with in-person and virtual participation options (Figure 2-1). An average of 70 individuals, representing over 30 organizations, registered for the public meetings. Meeting agendas focused on a broad range of IRP topics, including the overall process, timelines, impactful industry factors, resource evaluations, modeling inputs and methodologies, scenarios and sensitivities. To ensure ample opportunity for stakeholder feedback and questions, Q&A touchpoints were scheduled throughout each meeting. Public meeting presentations and summaries were shared with stakeholders on CEI South's IRP website, www.centerpointenergy.com/irp.

Figure 2-1 – 2025 Stakeholder Meeting Schedule

In addition to public meetings, CEI South hosted three technical meetings. These meetings included detailed and often confidential discussions of modeling inputs and assumptions. Interested stakeholders, with a signed NDA, were able to participate in the technical meetings as well as access confidential modeling data provided throughout the process through a secure file share site. These meetings offer a forum to discuss detailed assumptions and evaluation criteria to gain insight from multiple perspectives.

Section 8.6, Public Advisory Process, further details CEI South's public engagement, including a robust description of the process, key issues discussed, stakeholder feedback, data requests and stakeholder impact on the development of the IRP.

2.5. Planning Scenarios

To ensure CEI South's Preferred Portfolio performs reliably under a broad range of future conditions, the IRP includes a suite planning scenarios. Each scenario reflects a distinct "worldview" shaped by key uncertainties in environmental regulation, load growth, technology costs, fuel markets, and federal policy implementation. Together, they test the durability of candidate portfolios across plausible futures rather than anchoring planning decisions to any single forecast.

These scenarios share a consistent modeling foundation, using the same optimization tools, reliability targets, and engineering constraints, but differ in the external forces shaping utility operations. This framework allows CEI South to explore how shifts in demand, policy, and market conditions could alter resource needs, economic outcomes, and implementation feasibility.

2.6. Reference Case

The Reference Case represents CEI South's best estimate of future conditions and serves as the baseline for portfolio development and scenario evaluation. It reflects current law along with recent policy developments, specifically, developments in the proposed repeal of carbon regulation and modified elements of certain Inflation Reduction Act ("IRA") provisions. These assumptions were selected to reflect CEI South's planning judgment about the most likely regulatory, market, and economic trajectory over the 20-year horizon. To develop this scenario, CEI South worked with 1898 & Co. and other technical consultants to establish consistent and transparent assumptions across all major inputs:

- **Load Forecast:** CEI South's long-term energy and demand forecast was developed by Itron and reflects residential, commercial, and industrial usage patterns. It incorporates appliance efficiency trends, fleet electrification, long-term weather normalization, continued expansion of customer owned solar panels, and modest economic growth across the service territory.
- **Fuel Prices:** The Reference Case uses a consensus forecast approach for natural gas and coal, averaging inputs from sources such as S&P Global, Wood Mackenzie, Hitachi, and EVA. This reduces bias from any single forecast and reflects a transparent, market-aligned view of future commodity prices.
- **MISO Capacity Prices:** Scenarios include a forecast of MISO Zone 6 capacity prices, based on available projections from Hitachi, S&P Global, and Wood Mackenzie. These help inform portfolio revenue requirements and cost competitiveness resource portfolios, whether buying or selling excess capacity[8].

[8] Note that portfolios were not able to sell capacity in capacity expansion modeling runs. This helped prevent building more resources than needed for the purpose of selling capacity into the market.

- **CO_2 Price Proxy:** With the proposed repeal of Environmental Protection Agency ("EPA") Clean Air Act ("CAA") 111, the Reference Case only includes costs for compliance upgrades under framework modeled a proxy utilizing the Affordable Clean Energy ("ACE") Rule for existing coal resources, providing an efficiency requirement without assuming a carbon price.
- **Capital Costs:** Where available, baseline resource capital costs were developed utilizing a blend of All-Source RFP results and National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") curves, with adjustments made for inflation and supply chain constraints. These inputs ensure new technologies are evaluated on realistic, market-informed economics.
- **Resource Cost and Performance:** All-Source RFP data was supplemented with a comprehensive technology assessment by 1898 & Co., which was used to validate the capital, fixed and variable O&M, and operational performance assumptions of all resource types under consideration. Where data was not available from the All-Source RFP, the technology assessment was utilized. For example, CEI South utilized the technology assessment for several gas options, advanced nuclear, etc.
- **Demand-Side Resources:** A Market Potential Study ("MPS") developed with GDS Associates informed energy efficiency and demand response potential. These demand-side inputs were modeled on a consistent and comparable basis with supply-side resources to capture full system cost and performance tradeoffs.
- **Transmission Planning:** CEI South conducted a focused transmission study in parallel with generation strategy development to evaluate deliverability, upgrade needs, and local system constraints. The study identified areas where interconnection limitations or thermal constraints could impact various portfolios and ensured that Reference Case portfolios reflect realistic transmission system capabilities.

Portfolio modeling under the Reference Case was conducted using EnCompass, which performed a capacity expansion analysis to identify the least-cost resource mix, followed by chronological dispatch modeling to assess operational feasibility and system performance. The Reference Case was also used as the central comparison point in risk and scorecard evaluation to test how alternative portfolios perform under expected conditions.

2.7. Alternative Scenarios

While the Reference Case provides an outlook on likely future conditions, CEI South recognizes that long-term resource planning must account for the inherent uncertainty in regulatory policy, technology costs, economic development potential, and customer demand. To stress-test portfolios across a broad range of possible futures, the IRP included four Alternative Scenarios that were each structured to represent distinct, plausible deviations from the Reference Case.

These alternative scenarios are not forecasts or policy goals; instead, they serve as analytical “bookends” that help reveal how portfolios perform when challenged by differing policy mandates, commodity prices, demand growth rates, or environmental regulation.

Each scenario alters multiple input drivers simultaneously, such as fuel prices, load trajectories, capital costs, and environmental policy, to reflect a coherent and internally consistent worldview. Together, they provide insight into how different futures affect system needs, cost exposure, and implementation risk.

Alternate Reference Case
This scenario retains the same policy and regulatory assumptions as the Reference Case but introduces high load growth and is representative of several potential economic development opportunities. It explores the impact of potential large-scale developments such as emerging technologies like AI data centers, metal smelting plants, etc. that could rapidly accelerate electricity demand. This high-demand future was set up to evaluate potential portfolios to maintain affordability, operability, and resource adequacy under increased load conditions on an accelerated timeline. It also tests the responsiveness of transmission and interconnection pathways under fast buildout.

High Regulatory
The High Regulatory scenario reflects a future shaped by progressive federal or state decarbonization mandates. This includes a consensus carbon price utilizing Hitachi, EVA, and S&P forecasts as source data, faster fossil retirements, and tighter compliance obligations under the Clean Air Act and other environmental statutes. Clean energy deployment is further accelerated through economic incentives including the renewable tax credits under the IRA, supporting rapid expansion of renewables and storage. Portfolios in this future must accommodate a faster transition away from legacy assets while preserving reliability and cost control under accelerated timelines and regulatory pressure.

Alternate High Regulatory
This variation on the high regulatory scenario was created due to stakeholder input; it assumes continued regulation under the Clean Air Act, without direct carbon pricing, but introduces elevated load growth tied to electric vehicle adoption, enhanced electrification incentives, and economic expansion. While regulatory pressure is still present, the primary driver of change in this scenario is demand growth, coupled with slightly less regulation than the high regulatory scenario. Supply chain constraints and development

bottlenecks amplify the complexity of meeting new load, increasing capital costs and siting challenges. Energy efficiency program costs are assumed to continue at baseline levels; as there is greater opportunity for EE under increased load conditions. This scenario tests portfolios for their ability to scale under load and capital pressure while maintaining regulatory compliance.

Low Regulatory

The Low Regulatory scenario represents a future with further repeal of progressive environmental rules. CAA 111(b) and (d) are repealed, and no new decarbonization mandates are introduced. IRA provisions are cancelled, and resource decisions are driven primarily by market forces and asset-level economics. This Low Regulatory scenario emphasizes affordability and system stability, favoring legacy asset utilization and measured adoption of new technologies. This scenario helps identify portfolios that remain viable in policy-light conditions with limited external drivers for transition.

Scenarios Summary

The following graphic provides a side-by-side comparison of the five planning scenarios used in this IRP. Each scenario reflects a distinct set of assumptions related to environmental regulation, federal policy, demand growth, fuel pricing, capital costs, and technology adoption. This visual summary highlights the key drivers that differentiate these futures and illustrates how CEI South tested the robustness of candidate portfolios across a wide spectrum of uncertainties.

Figure 2-2 – Scenario Summary

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base
Alternate Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Much Higher	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	No additional CO_2 regulation	Higher	Higher	Higher	Higher	Base
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

Together, these five scenarios form the analytical backbone of CEI South's deterministic portfolio development and evaluation processes. Four of these worldviews, core scenarios (Reference Case, High Regulatory, Alternate High Regulatory, and Low Regulatory), served as the primary analytical foundation for this IRP. By modeling a range of regulatory, economic, and operational conditions, the IRP attempts to capture the spectrum of challenges that may emerge over the planning horizon. Each scenario was constructed to test how resource decisions could change relative to key drivers, as well as providing a view into how each portfolio would perform if applied to a different future. It also helps ensure that no single set of assumptions determines the outcome.

The fifth scenario, the Alternate Reference Case was developed as an alternate parallel analysis, providing additional perspective on the unique impact of a large load addition within CEI South's service territory. Since the load forecast and overall system need significantly differ from those found in the other scenarios, this worldview was modeled separately. This is discussed further in Section 6, The Alternate Preferred Portfolio.

This scenario-based framework enhances transparency and decision-making confidence. It enables CEI South to identify portfolios that are not only cost-effective under expected conditions but also resilient in the face of disruptive change. The insights from scenario modeling directly inform the risk evaluation and scorecard comparison process that follows, ultimately helping shape the selection of a Preferred Portfolio that balances affordability, reliability, resilience, stability, and environmental sustainability, and implementation feasibility across all plausible futures.

2.8. Planning Priorities and Guiding Principles

To bring clarity to how CEI South evaluates potential resource portfolios, this IRP is organized around the five pillars, into three overarching evaluation layers. These layers reflect the practical structure of utility decision-making; first, establishing whether a portfolio is technically viable, second, determining which feasible portfolios best align with customer priorities, stakeholder values, and long-term policy uncertainty, and third, ensuring all risks such as market, policy, and execution risks are accounted for.

Technical Requirements

Reliability – Reliability is foundational to electric system planning and refers to the ability of a portfolio to maintain sufficient generation capacity to meet peak demand. CEI South assessed resource adequacy using capacity expansion modeling that enforced MISO Planning Reserve Margin Requirements ("PRMR"), along with seasonal and annual load shape variation. Resource accreditation was modeled according to MISO's seasonal capacity valuation methodologies and included the transition to direct-loss-of-load accreditation methodology beginning in 2028. Portfolios that failed to maintain reserve adequacy were not included for consideration.

Stability – Grid operability refers to the capacity of a portfolio to maintain real-time and near-term system stability, including frequency regulation, voltage support, inertial response, and ramping adequacy. To evaluate operability, CEI South leveraged production cost modeling that simulated hourly dispatch and reserve commitment over the full planning horizon. These simulations tested portfolios for ability to manage renewable intermittency, net load variability, and contingency events while complying with reliability standards. Dispatchable thermal resources, fast-ramping assets, DR, and renewable generation were all critical to ensuring operability in modeled futures.

Resilience – Resilience reflects the ability of the electric system to prepare for, absorb, and recover from disruptive events, such as extreme weather, prolonged fuel supply limitations, correlated renewable shortfalls, and simultaneous generation derates. CEI South evaluated resilience through scenario-based and probabilistic-based modeling. Portfolio resilience was quantified through the total installed capacity of resources capable of fast start and spinning reserve benefits. Beyond the metrics, the inclusion of resources that offer black start capability were considered. Through price fluctuations, capacity factor limitations, and other variations in market conditions and assumptions, the portfolios were stress-tested and the system-wide response capability was evaluated.

Strategic Differentiators

Affordability – Affordability is evaluated using the Net Present Value of Revenue Requirements (“NPVRR”), which captures all generation-related costs, including but not limited to the following: capital, O&M, fuel, and market purchases – discounted over the 20-year planning horizon. This metric enables consistent comparison of portfolios with differing investment profiles and cost timing. CEI South examined NPVRR three ways: the mean value, and the $95^{th}/5^{th}$ percentile across 200 stochastic iterations. The 5^{th} and 95^{th} percentile represent possible boundary conditions for the 20-year costs, helping to measure cost risk. In addition to system-level costs, CEI South considered Incremental Electric Energy Burden, defined as total electric costs as a percentage of household income, to evaluate near to mid-term affordability of portfolio decisions on customer bills.

Environmental Sustainability – Environmental sustainability was assessed by analyzing portfolio emissions relative to expected environmental regulations and policy drivers. Modeling included assumptions around IRA incentives, potential Clean Air Act regulatory requirements, and carbon prices in the high regulatory scenario. Portfolios were also reviewed for alignment with stakeholder values around decarbonization, public health, and long-term climate risk mitigation.

Risk Management

MISO Market – Participation in the MISO market provides valuable flexibility, but increased reliance on market purchases introduces cost and reliability risks, especially as regional conditions evolve. Thermal retirements and rising renewable penetration may reduce capacity market liquidity and heighten price volatility during system stress.

To help illustrate tradeoffs, CEI South modeled energy market exposure across all scenarios, applying purchase limits mirroring system constraints and requiring portfolios to have a minimum level of self-sufficiency. This approach helps ensure resource adequacy even when market conditions are unfavorable.

Federal Policy – The Inflation Reduction Act included significant tax credits that enhance the economics of renewables, storage, and low-carbon technologies. While these incentives improve portfolio affordability and emissions performance, they also introduce planning risk due to evolving regulatory guidance, compliance complexity, and potential policy reversals. Scenarios were constructed with and without IRA tax incentives to evaluate boundary conditions, the One Big Beautiful Bill Act repeal and reinstatement of IRA incentives.

Execution and Supply Chain – Implementing large-scale resource transitions requires coordination across permitting, procurement, interconnection, and construction, each vulnerable to delays and cost escalation. National supply chain constraints, equipment lead times, and labor shortages present material risk to project execution.

CEI South incorporated these risks into modeling through cost sensitivities and contingencies, while also qualitatively assessing the scale and complexity of each portfolio. Portfolios with phased buildouts, technology diversity, and distributed development timelines were favored to reduce execution risk and support achievable, cost-effective implementation.

The final definitions of the objectives and metrics that were provided in the fourth Stakeholder meeting can be reviewed in the following table.

Figure 2-3 – Objectives, Measures, & Metrics

Objective	Measure	Metrics
Affordability: Consider portfolios' impact on the retail electric utility service providers' ability to provide affordable power across residential, commercial, and industrial customer classes	20-year NPVRR across 200 dispatch iterations under varying market conditions	millions$
	95th percentile of NPVRR across 200 dispatch	millions$

Objective	Measure	Metrics
	iterations under varying market conditions	
	5th percentile of NPVRR across 200 dispatch iterations under varying market conditions	millions$
	Incremental Electric energy burden (2030 – 2035)	% HH Income
Environmental Sustainability: Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation	CO_2 Intensity	Tons/ CO_2/kwh
	CO_2 Equivalent Emissions	Tons CO_2e
	SO_x and NO_x Emissions	Tons
Reliability: Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all times and withstand sudden disturbances **Resiliency:** Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions **Stability:** Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters	Unserved energy across 200 dispatch iterations under varying market conditions	MWh
	Spinning Reserve	Portfolio MW's that offer spinning reserve
	Fast Start Capability	Portfolio MW's that offer fast start
	Transmission reliability analysis	Dynamic VAR support ("MVAR") Short Circuit Ratio ("SCR")
Risk/Other:	Energy market purchase and sales	% (average, near/long-term)
	Capacity sales and purchases	$

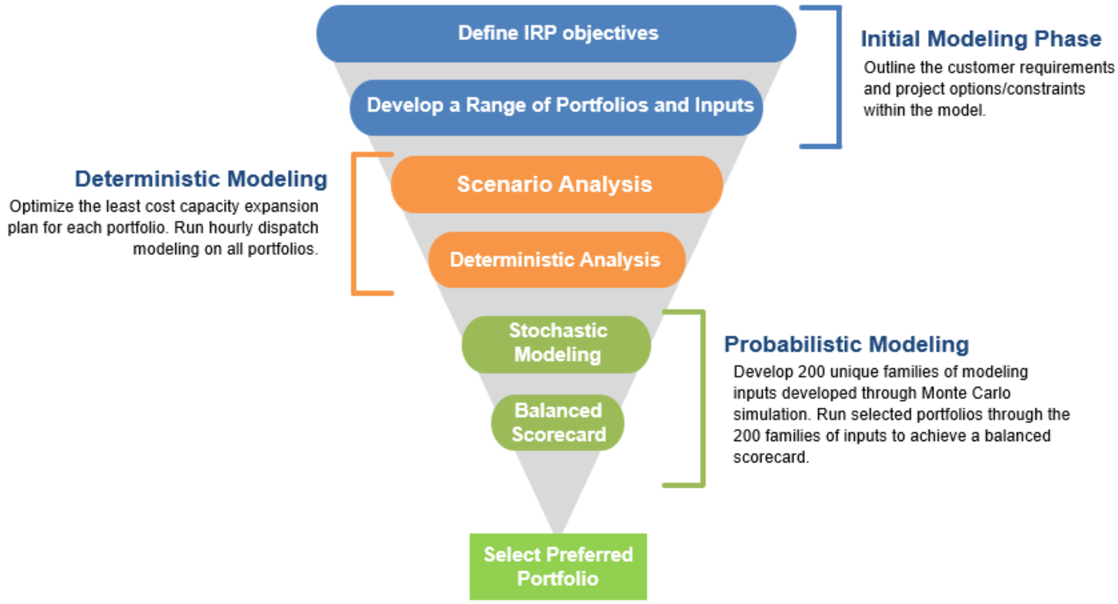
2.9. Comprehensive Portfolio Development & Testing

Following the completion of scenario design and modeling setup, CEI South initiated an iterative portfolio development process to explore and evaluate long-term resource pathways. Three major decisions were evaluated within this IRP: replacement of F.B. Culley 2 interconnection, the next three-year DSM Plan, and evaluation of F.B. Culley 3, CEI South's last remaining coal unit that it operates. For portfolio development, economic decisions for DSM programs were locked in prior to building out the final 12 portfolios. Then, the process began with initial runs of the primary scenarios designed to identify common themes across load, policy, and cost conditions. Resources that consistently emerged across scenarios, such as early storage or demand-side measures, were considered for inclusion in a "going-in" resource position to anchor subsequent modeling. Then CEI South focused on capacity need and built around various resource options to replace or maintain F.B. Culley 3.

Building from this foundation, CEI South constructed a broad set of candidate portfolios that reflect diverse planning priorities and technology pathways. These portfolios were then evaluated against CEI South's predefined criteria, including but not limited to technical performance, customer affordability, emissions outcomes, and implementation feasibility.

Figure 2-4 below illustrates the structured, multi-step approach used to refine, test, and compare resource strategies before selecting a final Preferred Portfolio. Note that with the inclusion of the Alternate Reference Case, this multi-step approach was performed once with the core scenarios and then again with the Alternate Reference Case inputs.

Figure 2-4 – Portfolio Development Process



Modeled Portfolios

Each portfolio represents a distinct pathway for meeting future energy needs, varying by generation mix, retirement timing, renewable adoption, and storage deployment. These resource portfolios test specific planning themes, and while some emphasize emerging resource types, others prioritize system flexibility. Several explore the role of legacy resources under evolving market and regulatory conditions. By modeling a wide range of options, CEI South was able to evaluate tradeoffs and performance across multiple dimensions, including reliability, cost, emissions, and implementation risk, under the four core planning scenarios. Twelve portfolios were evaluated in the final risk analysis. These portfolios and the selection process will be discussed further in Section 4, Portfolio Development and Evaluation.

The modeling framework included EnCompass and PSSE software packages to support both long-term system development and near-term operational analysis. These tools allowed CEI South to capture cost, reliability, and policy tradeoffs with appropriate technical rigor.

Capacity Expansion Modeling

For each scenario, capacity expansion modeling was used to identify optimal long-term resource plans that met planning reserve margins, and reliability criteria, while minimizing system cost. Fixed generation strategies, such as early coal retirement or prescribed storage additions, were used in certain runs to explore how portfolio configurations responded under controlled planning assumptions. Additionally, this strategy was used to create portfolios with a wide range of potential technologies to maintain needed capacity.

Production Cost Modeling

Once expansion plans were established, system dispatch and production costs were simulated on an hourly basis. This allowed CEI South to assess operational dynamics, including renewable integration, unit starts, expected unserved energy, and emissions output. These production cost insights ensured that modeled portfolios were not only cost-effective in theory but also viable under real-world system conditions.

Probabilistic Analysis

Recognizing the uncertainty inherent in long-term planning, CEI South performed targeted sensitivity analyses to test portfolio robustness. Key variables including fuel prices, load growth, carbon costs, energy sales, and capital expenses were varied within reasonable bounds. This helped identify portfolios that consistently performed well across multiple risk dimensions, even under adverse conditions.

Sensitivity Analysis

Sensitivity analysis is conducted to evaluate certain risks. It includes changing only one variable at a time to understand the impact of a single risk factor. In some cases, the sensitivity is used as a screening tool for ideas to see if the risk is worth further exploration within more comprehensive modeling. In other cases, it was used to provide more insight into the impact of one cost driver or explore potential differences in resource build out. Sensitivity analysis is particularly helpful in explaining isolated impacts that stakeholders or the company is interested in.

Together, these modeling efforts produced a well-rounded view of how candidate portfolios would perform across regulatory, economic, and operational contexts.

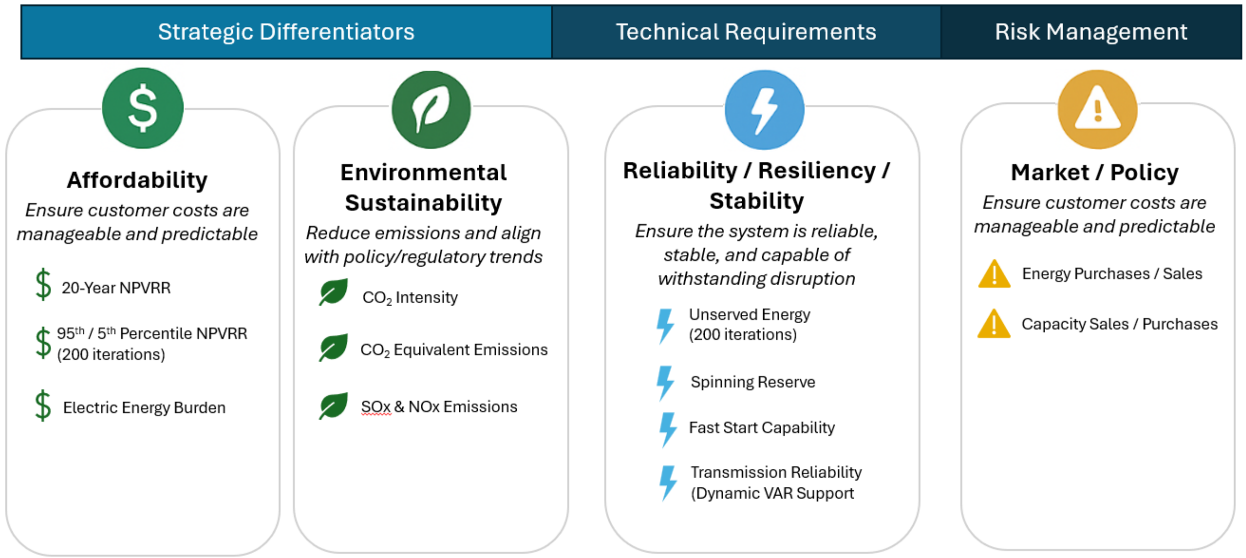
2.10. Portfolio Scorecard Evaluation

Once candidate portfolios were developed and tested, CEI South used a scorecard-based framework to compare performance across the three evaluation layers outlined above. This approach translated complex modeling outputs into a structured decision-making tool, allowing CEI South to balance technical feasibility with strategic value.

Evaluation Framework Summary

Figure 2-5 summarizes how CEI South's evaluation criteria are organized into the three assessment layers, Technical Requirements, Strategic Differentiators, and Risk Management. The image also illustrates the specific pillars, objectives, and performance metrics considered within each layer. This structure enables transparent, side-by-side comparison of portfolios across operational, economic, environmental and risk dimensions.

Figure 2-5 – Evaluation Objectives, Measures & Metrics



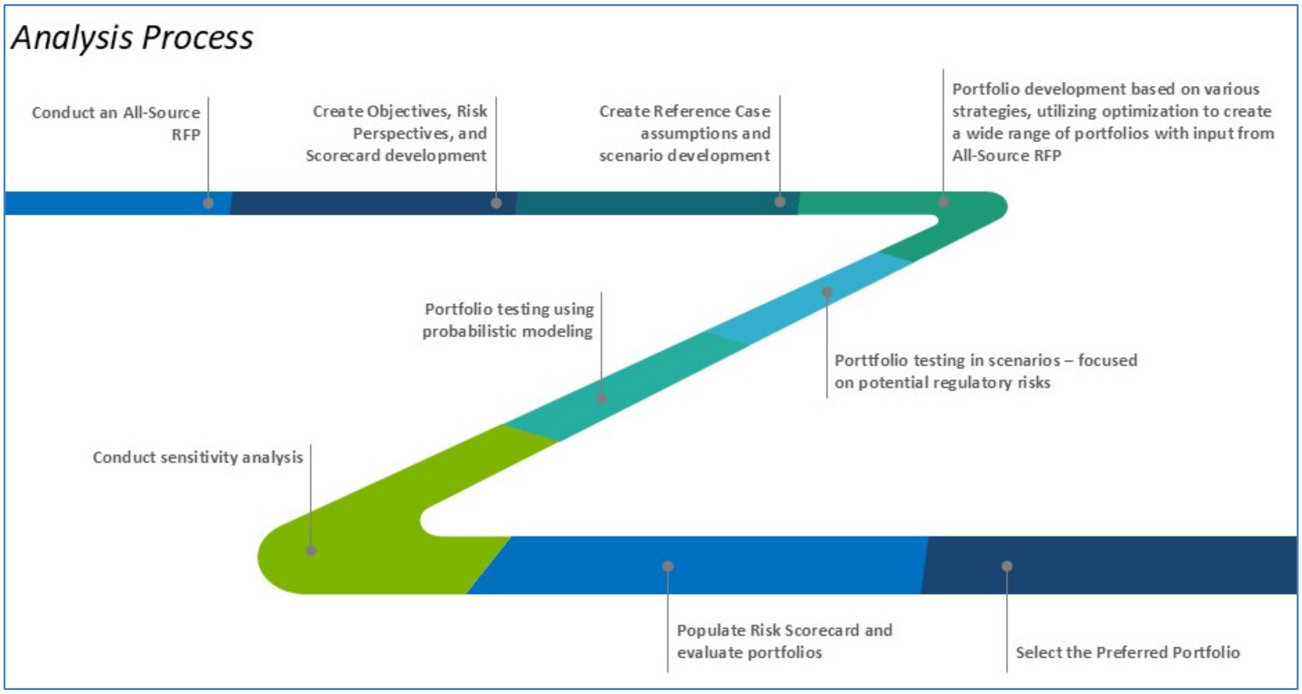
Together, this method ensures that CEI South's Preferred Portfolio is not only technically sound and cost-effective, but also robust under a range of future uncertainties. By integrating operational standards, long-term strategic objectives, and explicit risk considerations, the framework supports balanced decision-making and reflects CEI South's commitment to reliable, affordable, resilient, stable, and environmentally sustainable service for its customers. This structured approach also provides transparency and an opportunity for stakeholder engagement, reinforcing confidence in the IRP process and its outcomes.

2.11. Analytical Process & Tools

2.11.1. Analytical Roadmap

As shown in Figure 2-6, CEI South initiated the IRP process with the 2024 All-Source RFP (*Technical Appendix Attachment 2.1*), which provided current market data on resource availability and pricing. Following the 2024 All Source RFP, CenterPoint developed key evaluation metrics, perspectives, and scenario worldviews based on stakeholder input and existing knowledge. These scenarios, combined with additional planning considerations, were used to create potential future portfolios. Each portfolio was then evaluated through probabilistic modeling and various sensitivity analyses to quantify risk and performance under varied market conditions. Finally, the results were evaluated, and a Preferred Portfolio was selected.

Figure 2-6 – Analytical Roadmap



2.11.2. Modeling Tools

The primary modeling software used to assist in portfolio development, probabilistic modeling, and sensitivity analysis was the EnCompass capacity expansion and production cost simulation software package, licensed from Yes Energy. The National Database provided by Horizons Energy was used to represent the broader power grid beyond CEI South's service territory.

In parallel with generation system planning, a comprehensive transmission assessment was performed using the PSS/E software, licensed from Siemens. This analysis incorporated the MISO Transmission Expansion Planning ("MTEP") 2024 dataset to reflect the current state of the regional transmission network, supplemented with system-specific insights provided by CEI South.

2.11.3. Process Enhancements

Several enhancements were made to the IRP process in alignment with feedback from the previous IRP cycle and stakeholder requests. These updates included refinements to objectives and metrics, expanded sensitivity analysis, improvements to probabilistic modeling, and other process modifications intended to increase transparency and stakeholder engagement throughout the IRP development.

2.11.3.1. Enhancements to Objectives and Metrics

Additional scoring measures were introduced across the pillars to provide a more comprehensive assessment of the impacts evaluated in this study. Under the affordability metric, the 5th percentile of the NPVRR was added to the final scorecard, in addition to the traditional 95th percentile, to better represent the potential range of customer cost outcomes under varying future conditions. In response to stakeholder requests, electric energy burden was also incorporated as a new affordability metric. Accordingly, 5- and 10-year incremental electric energy burdens were calculated by dividing the bill impact in those years by the median household income in Vanderburgh County. This metric is intended to illustrate the potential near to mid-term impacts to customers associated with portfolio decisions made in this IRP cycle.

To strengthen the evaluation of environmental sustainability, new scoring measures were added to capture criteria air pollutants not previously reported in the scoring process. Specifically, cumulative tons of sulfur oxides (“So_x”) and nitrogen oxides (“No_x”) emitted were added to the environmental metrics. While previously captured in the broader CO_2 equivalent emissions intensity metric, this explicit inclusion provides greater transparency into portfolio environmental performance.

The transmission reliability analysis was conducted to assess system stability measuring the available dynamic reactive power (“VAR”) support and short circuit ratio (“SCR”). Both metrics were evaluated under single element outage (N-1) conditions. The dynamic VAR support metric quantifies the maximum available reactive power on the system during an outage event by summing the total system VAR capability and accounting for each generator’s reactive power contribution. Scenarios with lower dynamic VAR support may indicate potential voltage stability concerns. The SCR represents the ratio of the apparent power available at a given system bus following a fault to a benchmark apparent power value of 100 MW. Scenarios exhibiting lower SCR values are indicative of potential stability limitations. Together, these metrics help identify locations or scenarios where the system may require additional reactive support or reinforcement to maintain reliable operation.

Finally, in the risk category, capacity sales and purchases were added to the scorecard to better capture exposure associated with interactions in the market. This metric is intended to quantify the potential risks tied to capacity sales, particularly given their influence on the overall affordability results and customer cost outcomes. Moreover, highlighting reliance on capacity purchases in this way clearly demonstrates the risks related to market capacity availability and price volatility.

2.11.3.2. Enhancements to Probabilistic Modeling

One key enhancement to the probabilistic modeling framework involved the addition of energy sales variability within the stochastic analysis. To better reflect a range of potential market conditions, the model varied the limits of allowable energy sales across the 200 probabilistic iterations. These limits were implemented at the current transfer capability of 660 MW as well as reduced limits of 330 MW and 165 MW, with each limit applied to one-third of the total draws. This improvement provides a more realistic representation of operational flexibility and market exposure, while also preventing portfolio overreliance on market energy sales revenues to offset costs.

Another improvement expanded the probabilistic modeling of capital costs beyond renewables and storage to include all resources in the model. Each resource type was assigned high, base, and low capital cost forecasts to reflect a realistic range of potential outcomes. This addition allows the model to better capture uncertainty in future costs and improves the understanding of how capital cost changes influence overall portfolio performance.

2.11.3.3. Stakeholder Scenario Input

Throughout the IRP process, stakeholders were continually offered the opportunity to provide feedback and input for incorporation into the analysis. For example, during the initial stakeholder meeting, draft scenarios were presented, prompting stakeholders to request an additional scenario with substantially different key drivers. In response, CEI South developed an Alternate High Regulatory worldview, in which environmental regulations become more stringent, while load continues to grow a rapid pace due to electrification of heating equipment and vehicles, resulting in upward pressure on capital costs. Stakeholders also proposed the development of an Alternate Low Regulatory scenario—mirroring the original Low Regulatory scenario but incorporating lower projected load growth. This latter case was included as a sensitivity analysis rather than a new scenario.

2.11.3.4. Alternate Reference Case

This IRP coincides with a period of unprecedented uncertainty in the industry, particularly related to the rapid emergence of large loads seeking interconnection to the power grid. Following stakeholder interest surrounding the impacts of potential large load additions in CEI South territory and continued interest from multiple industries to locate in CEI South's territory, CEI South introduced an Alternate Reference Case. This analysis utilized IRP capacity expansion modeling to develop multiple portfolios for further evaluation using probabilistic modeling and selection of an Alternate Preferred Portfolio. More information on the Alternate Reference case can be found in Section 6, The Alternate Preferred Portfolio.

2.11.3.5. Expanded Sensitivity Analysis

To provide a more comprehensive understanding of portfolio performance under varying conditions, CEI South expanded the scope of sensitivity analyses performed in this IRP. These sensitivities examined the effects of several key factors, including the distributed solar incentive, large load additions, A.B. Brown 5 and 6 conversion costs, inclusion of F.B. Culley 2 storage, demand response term, and the Alternate Low Regulatory case. Together, these analyses provided greater insight into how changes in resource costs, load levels, distributed generation, and market conditions could influence portfolio development and overall system reliability.

Forecasts and Key Modeling Assumptions

Chapter 3

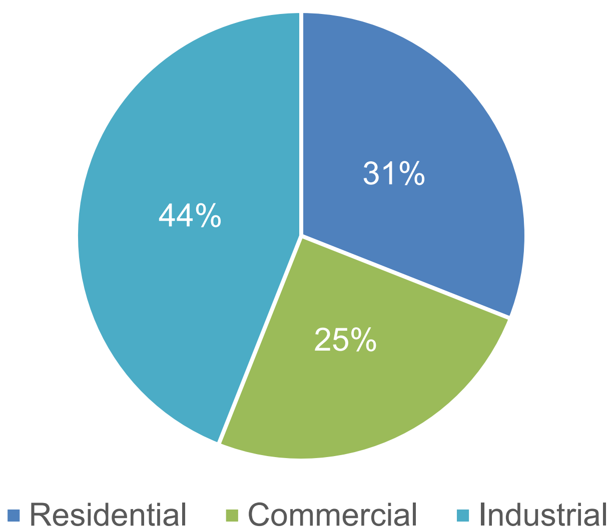
3.1. Load Forecast

3.1.1. Methodology

CUSTOMER TYPES

CEI South serves more than 150,000 electric customers in Southwestern Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of energy sales in 2024. The residential class accounts for 31% of sales with approximately 133,000 customers and the commercial class is 25% of sales; there are approximately 19,000 nonresidential customers. System 2024 energy requirements were 5,032 GWh with non-weather normalized system peak reaching 1,065 MW. Figure 3-1 shows 2024 class-level sales distribution.

Figure 3-1 – 2024 CEI South Annual Sales Breakdown



3.1.2. Forecast Drivers and Data Sources

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies and equipment market share data.

Itron used more than 10 years of historical energy and demand data within the energy and demand forecasts. This data is maintained by CEI South in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting.

There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate (rate closed to new premises). Information for these rates is combined for the purposes of forecasting residential average use per customer (“AUPC”). Similarly, small to large commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by S&P Global (formerly IHS Markit), which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output and employment.

Weather is also a driver of electric consumption. CEI South’s peak demand is traditionally in summer when temperatures are hottest. Air conditioning drives summer usage. Itron used a trended weather assumption for the normal weather in the sales and demand forecast to capture recent weather activity. The trended weather picks up the 0.06 degree annual increase in temperature the Evansville area has experienced since 1988.

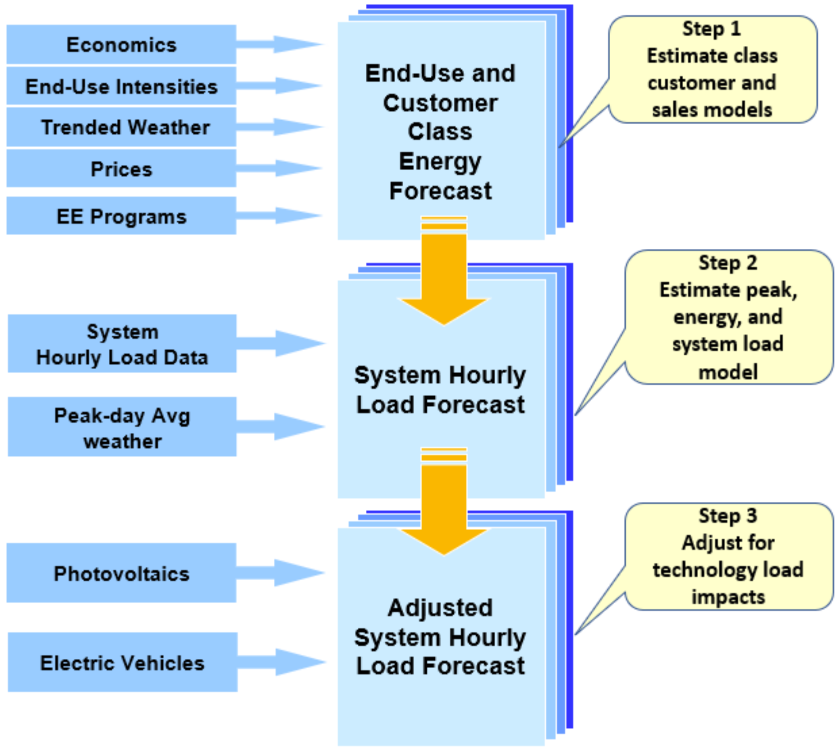
Itron provides regional Energy Information Administration (“EIA”) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following: electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data was adjusted to CEI South’s service territory based on the appliance saturation survey data.

3.1.3. Model Framework

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts.

Figure 3-2 shows the general framework and model inputs.

Figure 3-2 – Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance ownership trends, end-use efficiency changes, increasing housing square footage and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use ("SAE") model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price and weather. Both residential and commercial sales are forecasted using an SAE specification. Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

3.1.4. Reference Case

ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is considered a supply option and not a reduction to demand. Excluding DSM, energy requirements increasing 0.3% per year, summer peak demand increases of 0.5% per year and winter peak demand increases 0.3% per year growth over the next 20 years. The table below shows CEI South's energy and demand forecast; the forecast includes the impact of customer owned distributed generation, electric vehicles, trended weather (warmer summers and winters), company owned distributed generation (solar and landfill gas) and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on CEI South long-term energy and demand forecasts, including load shapes, see *Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report, Technical Appendix Attachment 3.2 Energy and Demand Forecast Model Inputs/Outputs (Confidential)*, and *Technical Appendix Attachment 3.3 CEIS 2024 System Hourly Load.*

Figure 3-3 – Energy and Demand Forecast

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2025	5,201,610		1,083		813	
2026	5,191,351	-0.2%	1,083	0.0%	810	-0.4%
2027	5,203,796	0.2%	1,088	0.5%	811	0.1%
2028	5,222,633	0.4%	1,093	0.5%	813	0.2%
2029	5,235,038	0.2%	1,098	0.5%	815	0.2%
2030	5,251,045	0.3%	1,104	0.5%	817	0.2%
2031	5,262,958	0.2%	1,108	0.4%	818	0.1%
2032	5,275,867	0.2%	1,113	0.4%	819	0.2%
2033	5,271,139	-0.1%	1,115	0.2%	818	-0.2%
2034	5,272,156	0.0%	1,118	0.3%	818	0.0%
2035	5,288,369	0.3%	1,124	0.5%	821	0.4%
2036	5,321,526	0.6%	1,133	0.8%	826	0.6%
2037	5,342,859	0.4%	1,140	0.6%	830	0.4%
2038	5,367,527	0.5%	1,148	0.7%	834	0.5%
2039	5,391,397	0.4%	1,155	0.6%	838	0.5%
2040	5,422,019	0.6%	1,163	0.7%	842	0.6%
2041	5,438,402	0.3%	1,169	0.5%	846	0.4%
2042	5,460,741	0.4%	1,177	0.7%	849	0.4%

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2043	5,483,087	0.4%	1,186	0.7%	852	0.4%
2044	5,512,360	0.5%	1,196	0.9%	857	0.5%
2045	5,535,614	0.4%	1,204	0.7%	860	0.4%
CAGR 25-45		0.3%		0.5%		0.3%

3.1.5. Alternate Scenarios

Itron developed three alternative scenario load forecasts as part of the IRP, one for each core scenario; they include a Low Regulatory, High Regulatory, and Alternate High Regulatory with electrification forecast. These forecasts are developed by altering the model inputs such as the EV/PV forecasts, economics, and end-use saturations and efficiencies. In addition to scenario forecasts, Itron developed four large load forecasts, three for the large load sensitivity and one for the alternate reference case. These forecasts assume the additional of a large load such as an industrial customer or data center.

Figure 3-4, Figure 3-5, and Figure 3-6 show the scenario, large load, and Alternate Reference Case forecasts.

Figure 3-4 – Alternate Scenario Forecasts

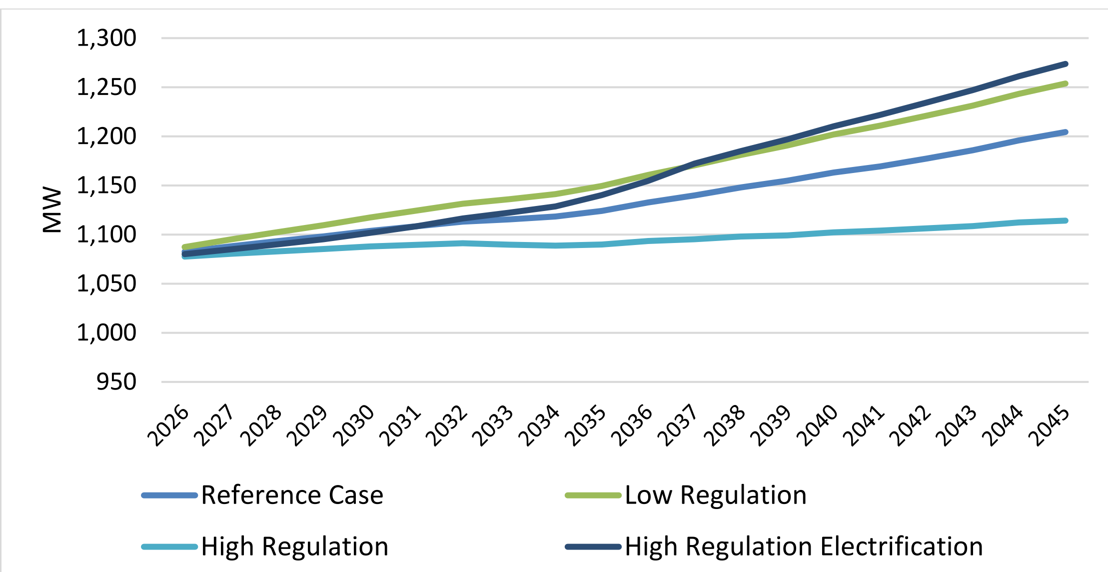


Figure 3-5 – Sensitivity Forecasts

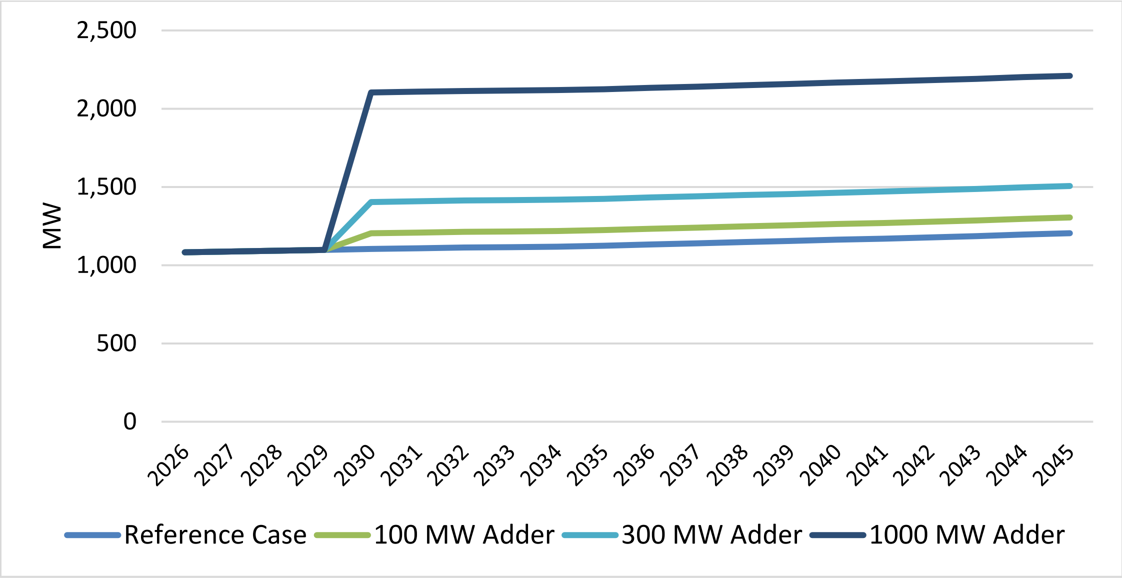
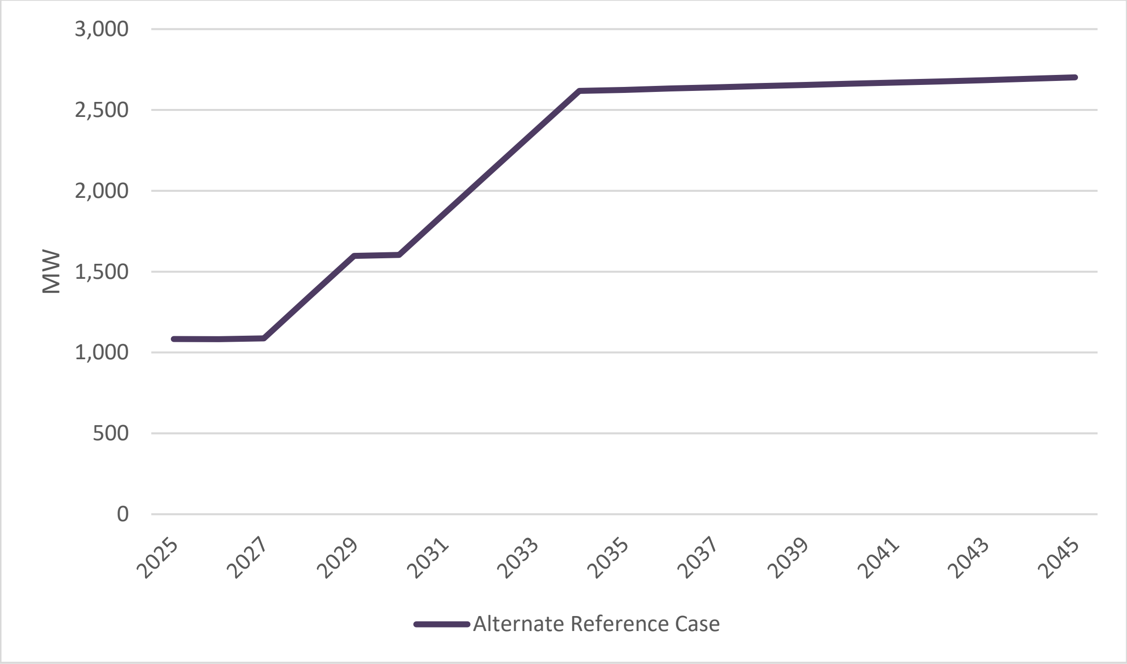


Figure 3-6 – Alternate Reference Case



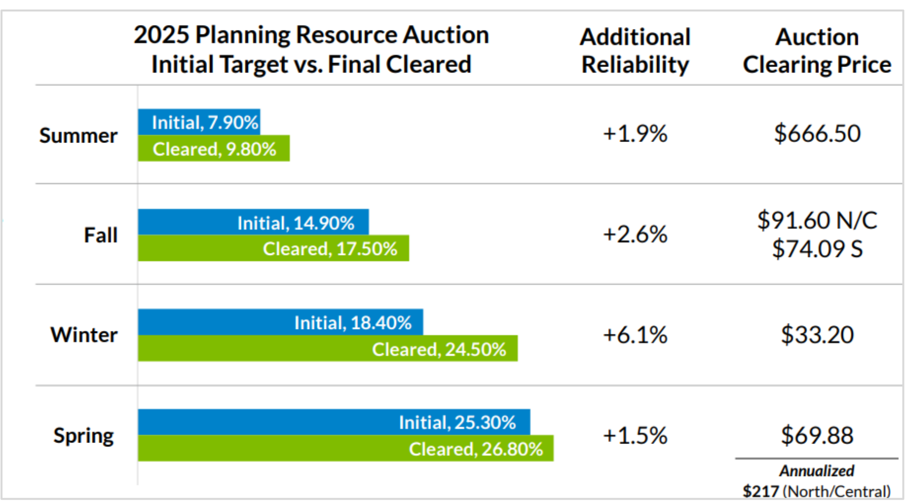
3.2. MISO

3.2.1. Planning Reserve Margin Requirement

MISO's Planning Reserve Margin ("PRM") is the percentage of additional capacity that Load Serving Entities ("LSEs"), including CEI South, must maintain above their forecasted peak demand to ensure grid reliability. The Planning Reserve Margin Requirement ("PRMR") is calculated based on the LSE's peak load forecast and the applicable PRM. The PRMR is further detailed by the Local Clearing Requirement ("LCR") which mandates how much of a LRZ PRMR must be met by generation resources physically located within that LRZ for each respective season. In recent years the number of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend is continuing as more baseload units are projected to retire in the coming years.

In 2024, FERC approved MISO's transition from a vertical demand curve to a reliability-based demand curve ("RBDC") for its capacity market, characterized by a sloped design, it is intended to improve MISO's capacity market by assigning value to surplus capacity based on its contribution to reliability, while also stabilizing prices, reducing volatility, and encouraging long-term investment in dependable energy resources. For LSE's the introduction of the RBDC adds complexity as each season has an initial PRM, but the final PRM can shift based on auction outcomes—requiring LSEs to estimate their potential final PRMR. The illustration in Figure 3-7[9] shows the impact of the RBDC on the 2025/2026 Planning Auction PRM.

Figure 3-7 – 25/26 RBDC Impact on the Planning Resource Auction



[9] "MISO Resource Adequacy PY 25-26: 2025 PRA Results Posting 20250529_Corrections". MISO Energy. May 29, 2025. https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf, page 5

3.2.2. Capacity Price

MISO's PRA is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013, as shown in Figure 3-8 below. These large swings have made it difficult to forecast prices. Outside of the 2022-2023 anomaly, prices were relatively low for MISO's Zone 6 market participants. However, in the last three Planning Years, since the implementation of the Seasonal Construct, prices have been steadily increasing. RBDC prices are in line with MISO expectations and send more accurate price signals that properly value incremental capacity.

Figure 3-8 – MISO Capacity Prices

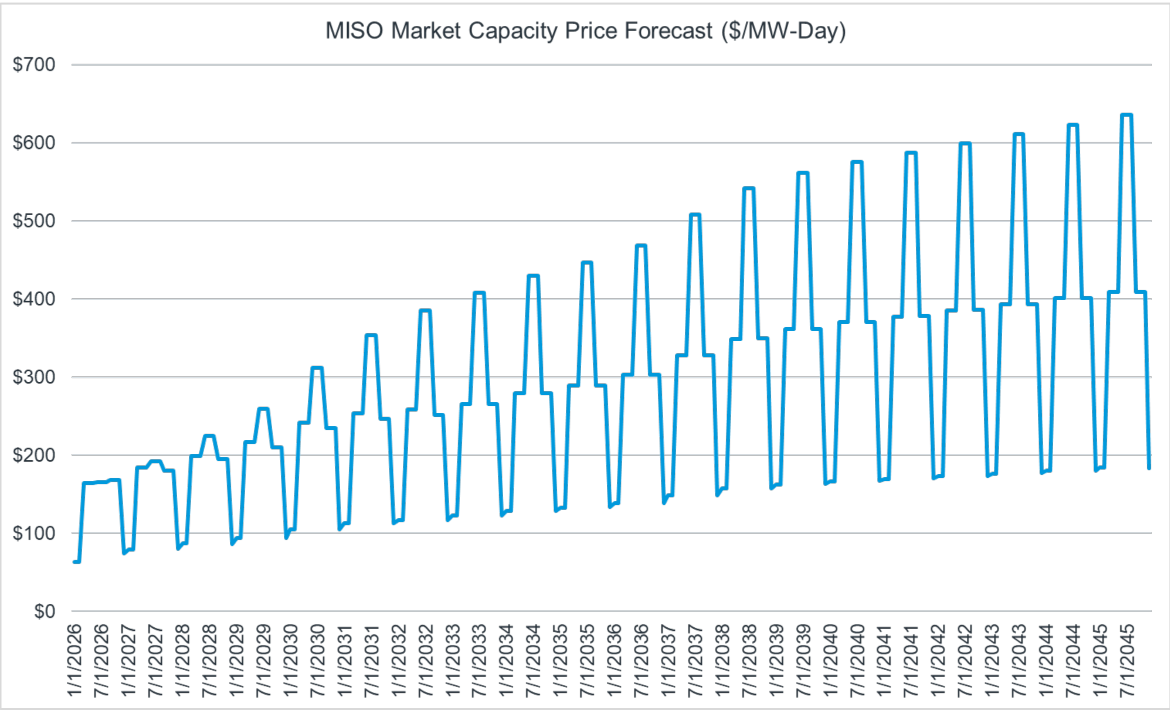
In Figure 3-9, the 2025-2026 seasonal PRA zone 6 cleared at $666.50 in the Summer, $91.60 in the Fall, $33.20 in the Winter, and $69.88 in the Spring, all in $/MW-Day.

Figure 3-9 – 2025-2026 MISO Seasonal Capacity Prices

Planning Year	Highest Clearing Price for MISO-region per MW-Day	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-Day
Summer	$666.50	$666.50
Fall	$91.60	$91.60
Winter	$33.20	$33.20
Spring	$69.88	$69.88

Forward-looking capacity prices were modeled using a consensus forecast from their sources, Hitachi, S&P Global, and Wood Mackenzie. This limits reliance on a single forecast and captures views from several experts. Seasonal capacity price forecasts are given in Figure 3-10. As illustrated below, the capacity price in all seasons is increasing over time, with the summer capacity price increasing at the quickest pace.

Figure 3-10 - MISO Market Capacity Price Forecast



3.2.3. Addressing Resource Adequacy and Reliability Challenges

To address escalating reliability risks and resource adequacy challenges, MISO is executing a series of strategic reforms guided by its Reliability Imperative—a framework launched in 2020 that defines the shared responsibility among MISO, its members, and states to ensure grid reliability amid rapid change. The Reliability Imperative is structured around four pillars: Market Redefinition, Transmission Evolution, System Enhancements, and Operations of the Future, each driving targeted initiatives to manage uncertainty, integrate new technologies, and modernize planning and operations.

Key reforms have included the transition to a seasonal PRA in Fall 2022, the implementation of the RBDC effective June 3, 2024, and resource accreditation reforms scheduled for full rollout by the 2028–2029 planning year. These changes improve capacity valuation, align planning with seasonal risks, and incentivize reliable resource performance. MISO's interconnection reforms, including the Expedited Resource Addition Study ("ERAS") process launched in May 2025, aim to accelerate critical resource deployment, with the first Definitive Planning cycle beginning January 2026.

Additionally, FERC Order 881, effective December 31, 2028[10], requires utilities to implement ambient-adjusted transmission line ratings, enhancing grid efficiency and transparency, which may require improved forecasting tools and data integration to reflect dynamic transmission capabilities. FERC Order 2222 mandates the integration of Distributed Energy Resources ("DERs") into wholesale markets. MISO's compliance efforts in 2025 have involved building new workflow models and structuring communication frameworks for key roles that CEI South will incorporate into future IRPs as it becomes clearer how DER aggregation, visibility, and dispatchability affects our system. The impact of these regulatory changes is addressed in more detail below.

3.2.3.1. Direct Loss of Load ("DLOL") Resource Accreditation

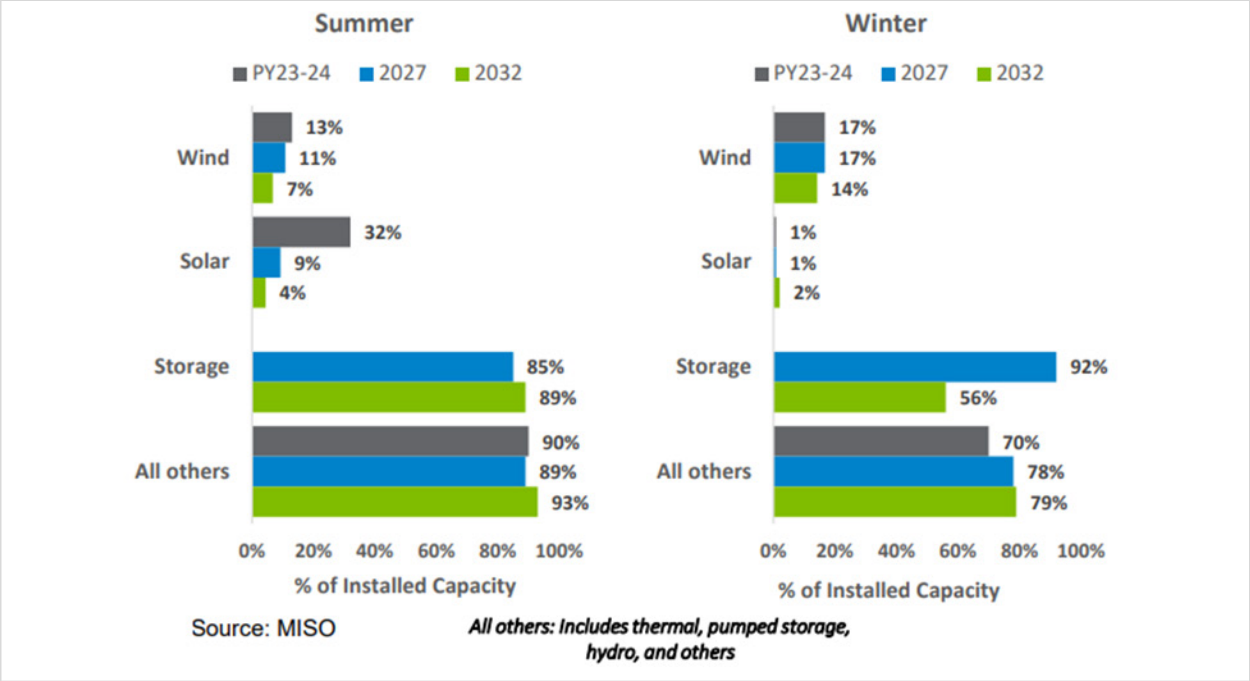
MISO is undergoing a pivotal transformation in its resource portfolio. A substantial portion of dispatchable thermal generation is approaching retirement, while being replaced by a growing share of weather-dependent, intermittent wind and solar resources. This shift combined with the increasing penetration of variable generation and the rising frequency of extreme weather events is fundamentally altering the nature of system risk and presenting new challenges to maintaining reliable grid operations, as part of MISO's broader Resource Availability and Need ("RAN") initiative (2019) and Market Redefinition, MISO proposes a two-step accreditation framework, known as the DLOL-based methodology, to address emerging reliability challenges and ensure a balanced, diverse resource mix. This approach also builds on recent reforms, including FERC's approval of Seasonal Accreditation ("SAC") and the shift to a seasonal PRA.

MISO's proposed DLOL-based resource accreditation methodology involves two steps. First, it uses a probabilistic assessment to estimate a resource's expected contribution to reliability by analyzing class-level performance during high-risk periods, based on 30 years of weather and load data through Monte Carlo simulations. Second, it applies a

[10] "Commissioner Rosner's Concurrence on Order Granting Extension of Time re MISO, Inc. under ER22-2363 | Federal Energy Regulatory Commission". FERC News. June 6, 2025. https://www.ferc.gov/news-events/news/commissioner-rosners-concurrence-order-granting-extension-time-re-miso-inc-under.

deterministic assessment that evaluates each resource's historical performance during critical reliability hours to assign accreditation within its resource class. Seasonal and resource-specific impacts under MISO's DLOL based resource accreditation methodology reflect a shift in reliability risk from summer to winter, which significantly affects solar and wind resources. Solar accreditation declines as penetration increases due to reduced effectiveness during evening risk hours, while both wind and solar receive lower proposed accreditation values compared to current methods. In contrast, thermal and storage resources maintain more stable accreditation levels, though they are still influenced by probabilistic risk modeling. The DLOL methodology began a three-year transition starting September 1, 2024, with full implementation targeted for the 2028/29 Planning Year.

Figure 3-11 – MISO DLOL Accreditation Forecast



3.2.3.2. Demand and Emergency Resources Accreditation Reforms

MISO's Demand and Emergency Resources Accreditation Reforms introduce a performance-based approach to resource accreditation, emphasizing availability during high-risk reliability periods. Utilities must now account for seasonal and hourly availability rather than static nameplate capacity and adjust planning reserve margins accordingly. With emergency DR programs being phased out starting in 2025 and full implementation of the reforms by Planning Year 2028–2029, IRPs developed during this transition must reflect evolving accreditation values and anticipate reduced capacity credits for certain demand-side resources[11].

3.2.4. Generation Interconnection Process

Before a new generating facility can connect to the MISO-controlled transmission network, the new energy source is evaluated and approved through the MISO Generator Interconnection Process. The Generator Interconnection Process ("GI") defines the steps an interconnection customer and MISO take to move interconnection requests through the interconnection queue[12].

The three steps are: Pre-Queue, Application Review and Definitive Planning.

Pre-Queue: Provides interconnection customers with an overview of the Generator Interconnection process, including timelines and output expectations.

Application Review: MISO reviews the request, checks customer readiness, and conducts a mandatory scoping meeting.

Definitive Planning Phase ("DPP"): The final phase of MISO's generator interconnection study process where MISO conducts reliability and deliverability studies that determine whether there is available transmission capacity to accommodate the interconnection of a new, proposed generation facility or whether network upgrades are needed.

Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement ("GIA") process. After satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the MISO transmission system and depending on the transmission service selected, participate, and receive full accreditation in the MISO energy and capacity markets.

3.2.4.1. Interconnection Reforms

In parallel to MISO's strengthening of system reliability and resource adequacy initiatives, MISO is advancing key interconnection reforms to meet the 373-day processing timeline per MISO's Tariff. This includes implementing a queue volume cap to manage the surge

[11] "IRP Contemporary Issues Technical Conference". IN.GOV-IURC. June 6, 2024. https://www.in.gov/iurc/files/MISO-Resource-Accreditation-Reform-IRP-Contemporary-Issues-Technical-Conference-06062024.pdf

[12] Midcontinent Independent System Operator, Inc., Generator Interconnection and Retirement, available at https://www.misoenergy.org/planning/resource-utilization/generator-interconnection/

in interconnection requests, limiting new proposals to 50% of each region's non-coincident peak load to reduce delays and improve study accuracy. Alongside this, financial reforms have increased milestone payments and introduced penalties for late-stage withdrawals from the queue to discourage speculative projects and streamline the process. SUGAR (Suite of Unified Grid Analyses with Renewables) is MISO's advanced automation tool developed to streamline and accelerate interconnection studies. SUGAR significantly reduces engineering time from months to minutes by automating tasks like base case creation, voltage and thermal violation detection, and contingency analysis. It has demonstrated a 99.2% match rate with legacy MISO studies and is being used to support Phase 1 of the DPP. Together, these coordinated initiatives reflect MISO's commitment to efficient resource integration and maintaining system reliability[13].

3.2.4.2. Expedited Resource Addition Study ("ERAS")

Resource adequacy is the cornerstone of MISO's FERC-approved ERAS process, which was established to accelerate the interconnection of generation resources deemed critical for near-term reliability. ERAS enables states or load-serving entities like CEI South to nominate projects that directly address resource adequacy needs such as meeting planning reserve margins or replacing retiring capacity allowing these projects to bypass the traditional queue. Designed as a temporary mechanism to mitigate emerging reliability risks until broader queue reforms are implemented by 2028. ERAS is limited in scope and duration, concluding by August 31, 2027, with a cap of 68 projects and a maximum of 15 per quarter[14].

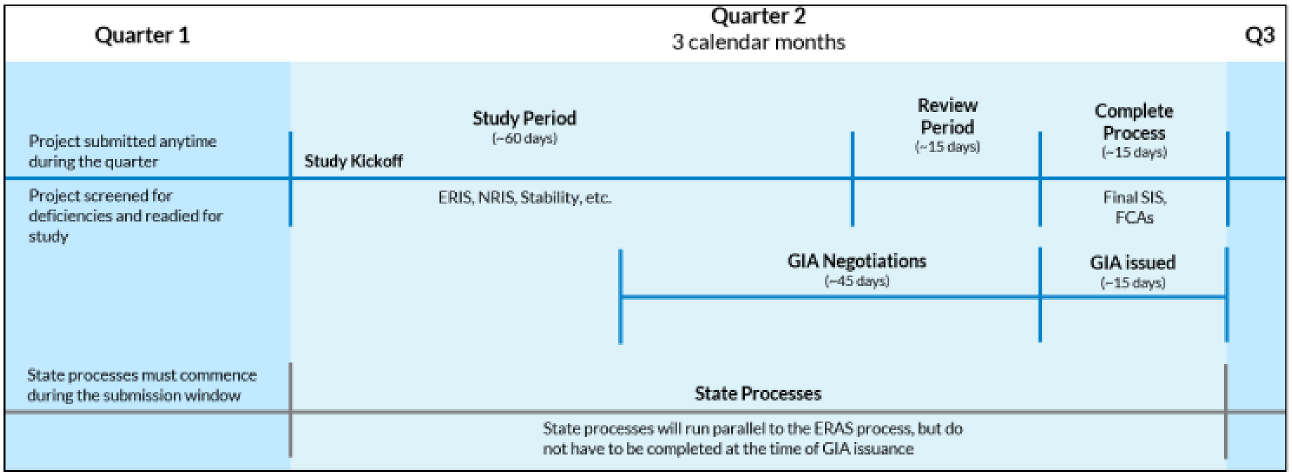
Eligible projects must resolve a specific load addition or resource adequacy deficiency, be commercially operable within 3–6 years of submission, and receive interconnection service capped at 150% of the identified need within the same Local Resource Zone. Each nomination must be verified by the Relevant Electric Retail Rate Authority ("RERRA") to confirm the necessity of the project. As of September 2025, MISO has received 47 ERAS applications totaling 27 GW of capacity. These projects represent a diverse mix of energy sources—primarily gas (74%), followed by nuclear (15%), solar and wind (each 4%), and storage (3%). The applications span multiple states, indicating a

[13]"MISO Dashboard". MISO Energy. June 26, 2025. https://www.misoenergy.org/engage/MISO-Dashboard/generator-interconnection-queue-improvements/

[14] 2025-11-25_193 FERC ¶ 61,168_Docket No. ER25-3543-000729602.pdf. FERC Order approving MISO's September 2025 request to increase from ten projects to fifteen projects per quarter.

broad geographic interest in expedited resource development[15]. Under the ERAS process GIAs are expected to be executed as early as Q4 2025.

Figure 3-12 – ERAS Timeline



3.2.5. Impact of Regulatory Changes

Recent FERC orders 2023, 2222, and 881 introduce significant changes led by MISO. It also requires transmission providers to evaluate Grid Enhancing Technologies ("GETs") to improve system efficiency These orders may promote more agile, data-driven, and distributed approaches to resource planning in the future, requiring adaptation to evolving grid realities and regulatory requirements.

<u>FERC Order 2023:</u>

Requires MISO and other Regional Transmission Operators to overhaul their generator interconnection processes. It mandates MISO to modernize its generator interconnection process by adopting a "first-ready, first-served" cluster study model, enhancing transparency, and enforcing stricter timelines. It calls for MISO to prioritize commercially viable projects, streamline queue management, and evaluate Grid Enhancing Technologies to optimize transmission capacity. The order also reinforces cost allocation principles, ensuring developers fund necessary upgrades[16]. These reforms aim to reduce interconnection delays, support renewable integration, and align MISO's procedures with

[15] "Board of Directors – System Planning Committee". MISO Energy. June 10, 2025. https://cdn.misoenergy.org/06_2025-09-16_SPC_Open_Long%20Term%20Resource%20Adequacy%20%20Interconnection%20Queue%20Update_FINAL717559.pdf., page 6

[16] "Fact Sheet – Improvements to Generator Interconnection Procedures and Agreements". FERC. July 27, 2023. https://www.ferc.gov/news-events/news/fact-sheet-improvements-generator-interconnection-procedures-and-agreements

FERC's national standards. Compliance filings were submitted in April and May 2024, and continuing through 2026. MISO continues to work with stakeholders to enhance transparency and align its processes with FERC's expectations for Transmission Evolution initiatives.

FERC Order 2022:

Issued in September 2020, requires RTOs/ISOs to allow DERs to aggregate and participate in wholesale markets. MISO submitted its second compliance filing in early 2025, which FERC accepted, allowing full market integration of DER aggregators by 2030. Utilities will adapt IRPs by integrating DERs more explicitly into planning models, potentially revising forecasting methods to include aggregated DER impacts, and coordinating more closely with distribution system operators and aggregators. Intermediate steps may allow limited participation under demand response models between 2027 and 2029. MISO is currently upgrading its market platform and settlement systems, with major milestones expected in 2025–2028.[17]

FERC Order 881:

Mandates that all U.S. transmission providers—including RTOs, ISOs, and utilities implement Ambient Adjusted Ratings ("AARs")[18]. This order requires CEI South to develop a Facility Rating Methodologies, ensuring hourly electronic updates of line ratings based on forecasted ambient temperatures, and maintaining secure databases of rating methodologies. This shift enhances grid efficiency by unlocking unused transmission capacity based on real-time weather data.

Overall, Order 881 drives more accurate, cost-effective, and flexible transmission resource planning. Originally set for July 2025, MISO requested and received an extension to December 31, 2028, citing vendor delays and software readiness issues. Despite the delay, stakeholders and FERC encourage MISO to implement components of AARs ahead of schedule to reduce congestion costs and improve reliability.

3.3. Fuel

The thermal units in this analysis are fueled by three main sources: natural gas, coal, and uranium. Fuel forecasts were obtained from a variety of sources in order to capture perspectives from multiple industry experts, allowing CEI South to be more transparent and

[17] "Distribution Energy Resource Task Force (DERTF)". MISO Energy. April 11, 2024. https://cdn.misoenergy.org/2024%20Order%202222%20Compliance%20Framework631391.pdf

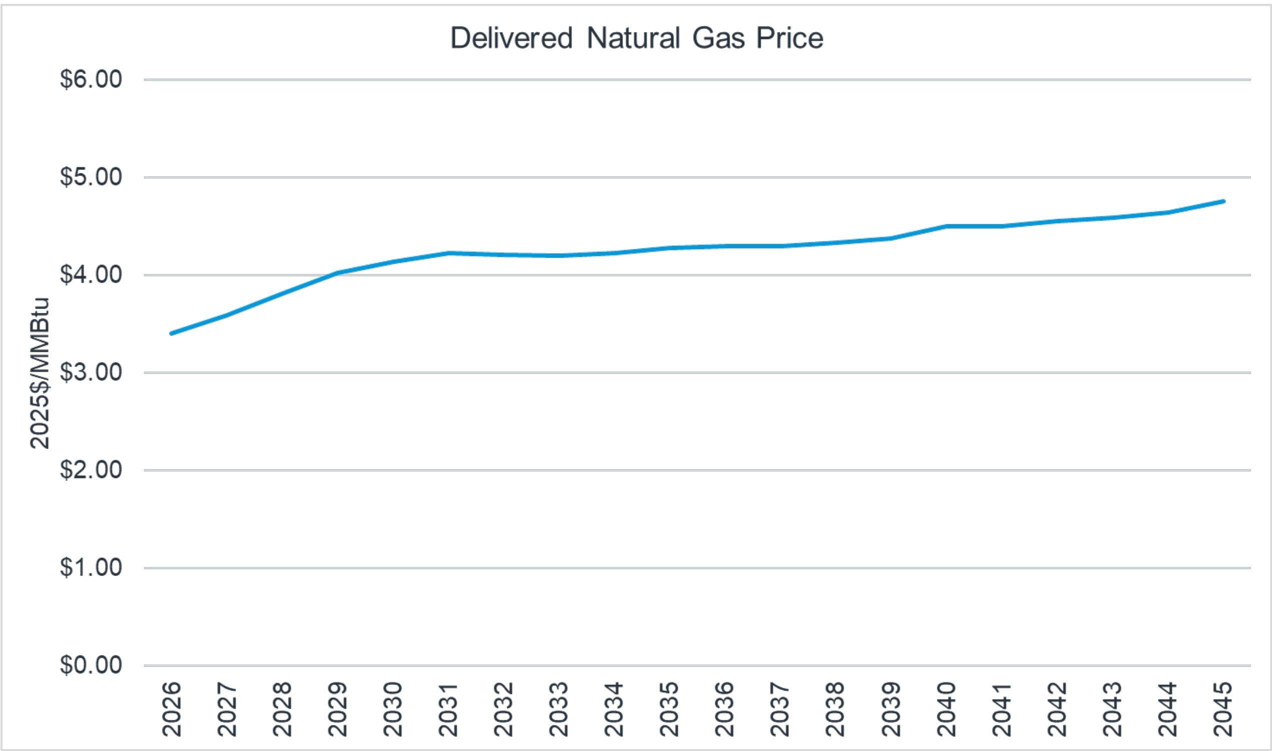
[18] "FERC Rule to Improve Transmission Line Ratings Will Help Lower Transmission Costs". FERC. December 16, 2021. https://www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs

less reliant on a single perspective in the planning process. For natural gas and coal, forecasts from Wood Mackenzie, Hitachi, S&P Global, and EVA were averaged.

3.3.1. Natural Gas

In addition to the sources mentioned above, CEI South utilized NYMEX data to adjust the Henry Hub price based on historical price separation between Henry Hub and delivered gas prices to the CEI South system. Figure 3-13 displays the delivered natural gas price forecast for the Reference Case.

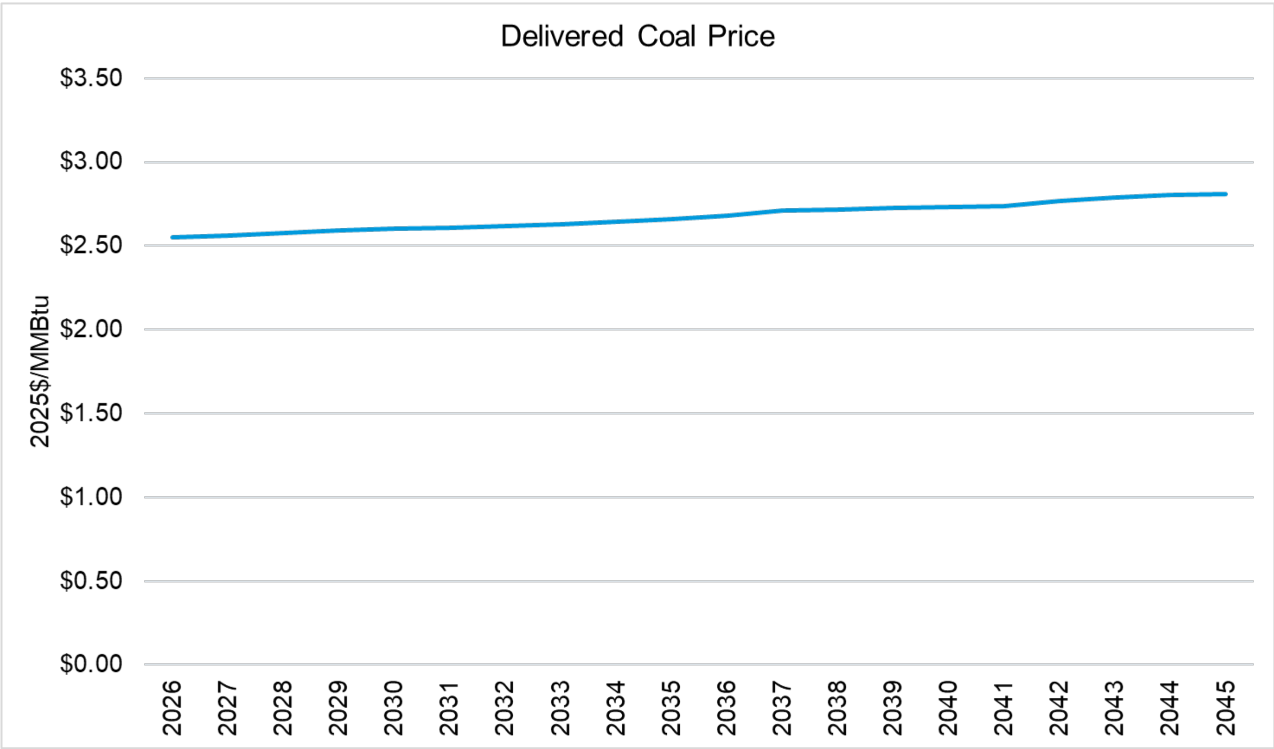
Figure 3-13 – Reference Case Natural Gas Price Forecast (2025$/MMBtu)



3.3.2. Coal

CenterPoint's coal facility is fueled by Indiana-mined coal. Similar to natural gas, a transportation adder based on historical data was included to obtain a price for coal delivered to CEI South. Figure 3-14 displays the consensus coal price forecast for the Reference Case.

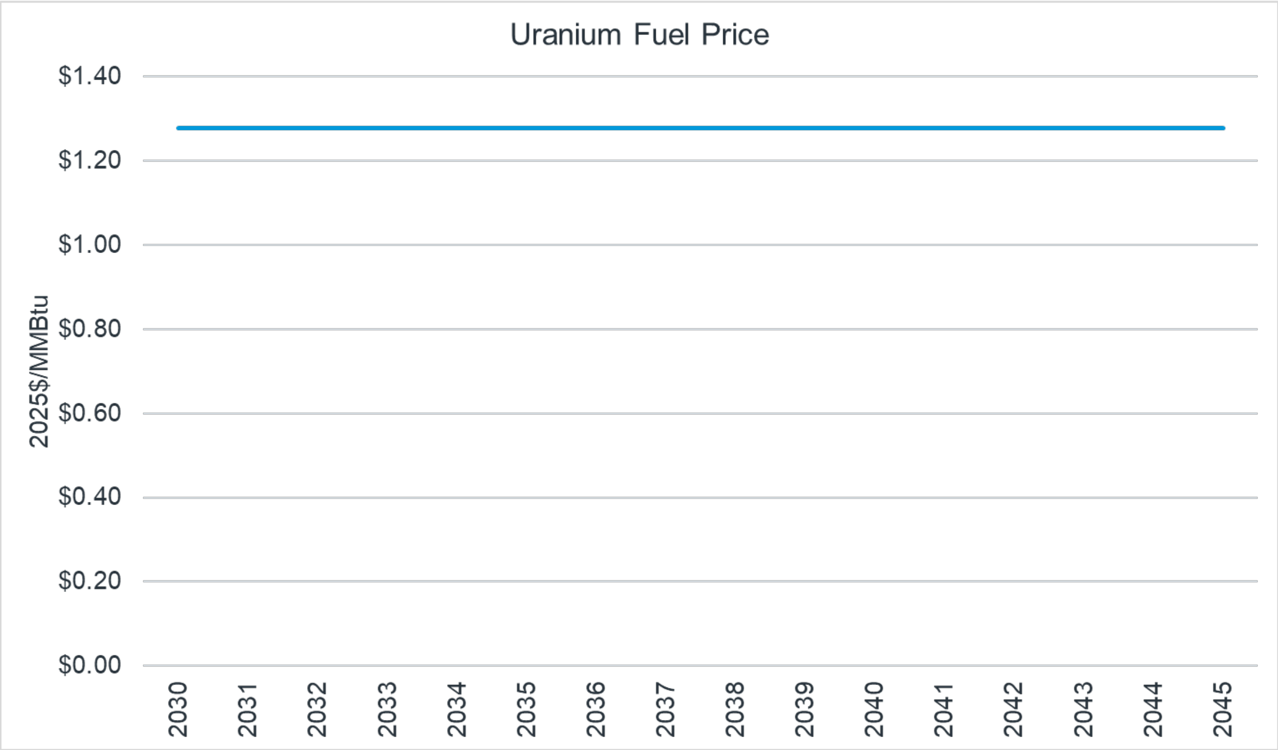
Figure 3-14 – Reference Case Coal Price Forecast (2025$/MMBtu)



3.3.3. Uranium

Nuclear power plants use uranium fuel to produce heat. The uranium price forecast, shown in Figure 3-15, was sourced from the 2024 Annual Technology Baseline published by the NREL[19]. Because uranium is a fuel associated with an emerging technology in NREL's dataset, the forecast begins in 2030 and assumes a constant price throughout the study period.

Figure 3-15 – Reference Case Uranium Price Forecast (2025$/MMBtu)

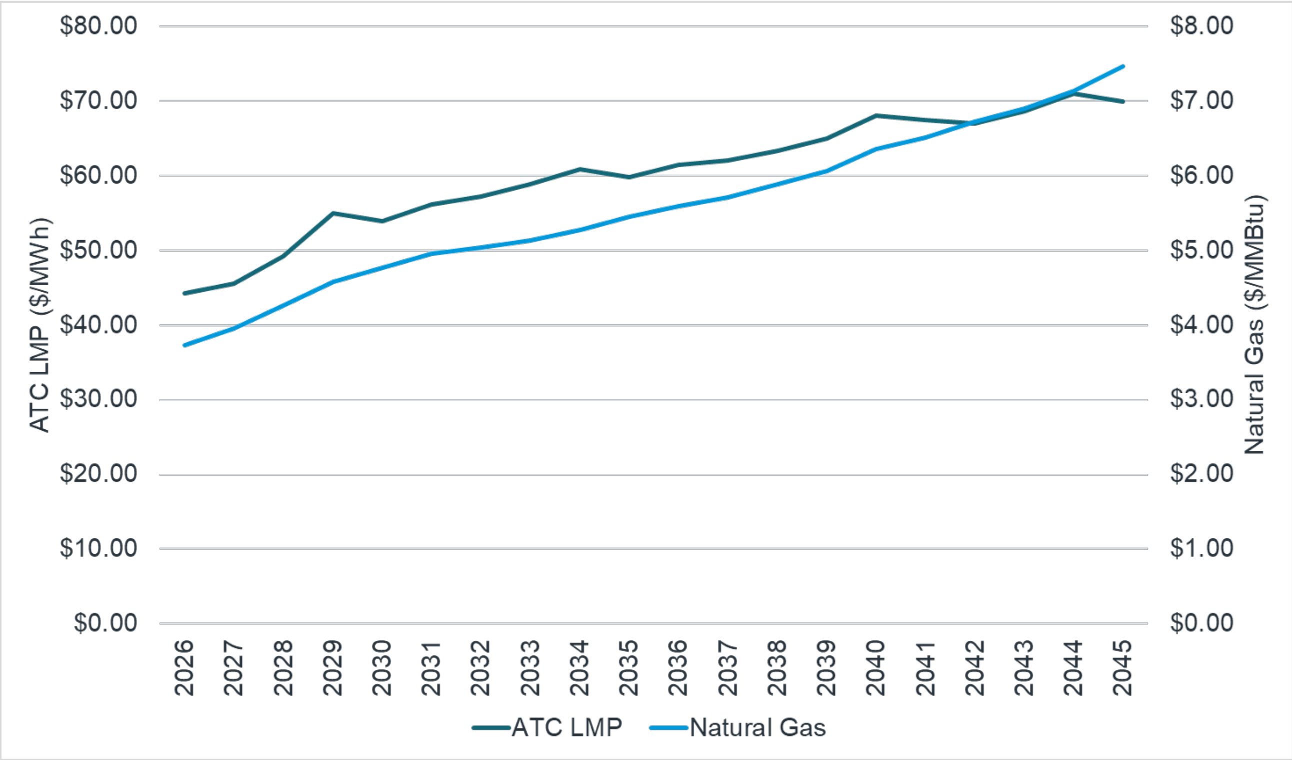


3.4. Power Prices

Energy prices as an input into the IRP model were developed by 1898 & Co. using the EnCompass software. The starting model for the analysis was the national database licensed from Horizons Energy, LLC. Updates to the National Database were made to specifically align the input assumptions with the IRP Scenario assumptions. A summary of around the clock ("ATC") power price forecast can be seen below in Figure 3-16 which also illustrates the macro correlation to natural gas prices over the study period.

[19] The NREL ATB Excel workbook can be found here: https://atb.nrel.gov/electricity/2024/data. Uranium fuel costs were taken from the "Nuclear" tab. The moderate forecast for a small nuclear facility was used.

Figure 3-16 – Reference Case Power Price Forecast (Nominal $)



3.5. Environmental Regulations

The current modeling analysis includes relevant costs primarily focused on evaluation of alternatives to comply with the ELG, 316(b), and ACE rule proxy requirements where applicable. The costs presented below are preliminary screening level estimates used for modeling purposes only. Individual elements of the estimate may go up or down depending on final design specifications, permit requirements, and vendor bids. It should be noted that environmental regulatory requirements represent one of the areas presenting significant uncertainty with respect to the current administration's activities related to regulatory reform and potential future requirements related to greenhouse gas emissions from fossil fuel-fired generating units.

3.5.1. Effluent Limitations Guidelines ("ELG")

F. B. Culley Unit 3 is equipped with dry fly ash and dry bottom ash handling systems, thereby eliminating ash transport water discharges in compliance with the current requirements of the ELG rule. The Spray Dryer Evaporator Zero Liquid Discharge system has been completed and is online, timely meeting the ELG requirements that are incorporated into the NPDES permit and eliminating the discharge of FGD Wastewater. F.B. Culley Unit 2 still utilizes bottom ash transport water and is slated for retirement on December 31, 2025, in compliance with the requirements of its NPDES permit.

In May 2024, EPA published updated Effluent Limitation Guidelines rule, which contains a provision that requires Zero Liquid Discharge ("ZLD") of unmanaged Combustion Residual Leachate ("CRL") for facilities that do not permanently cease combustion of coal by the end of 2034. This technology is factored into scenarios that include operating Culley Unit 3 on coal past 2034.

3.5.2. Coal Combustion Residuals ("CCRs")

Company continues to close its ash ponds in timely compliance with the requirements of the CCR rule, which was first promulgated in 2015 and has undergone multiple revisions since implementation. The timing of the closures is based on forced closure (i.e., exceedance of Ground Water Protection Standard ("GWPS") and failure of aquifer location restriction) and compliance with the Site-Specific Alternatives to Initiate Closure plans that were submitted to U.S. EPA under the requirements of the CCR Part A rule. The base cost for the closures does not change regardless of future generation and closure cost for CCR units is not part of the IRP modeling.

3.5.3. Greenhouse Gas Regulations

As noted previously, the federal regulation of greenhouse gases is an area of significant uncertainty stemming from years of litigation and continual swings in requirements between federal administrations. In June 2019 the first Trump administration finalized the ACE rule, which replaced the 2015 Clean Power Plan (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels) with a requirement that existing fossil fuel-fired generating units meet certain efficiency targets. This rule was referred to as the Affordable Clean Energy Rule ("ACE"). The ACE rule was repealed and replaced by the Biden administration's New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units which was effective on July 8, 2024 (Biden Rule). The Biden Rule is currently in effect; however, on June 17, 2025, the second Trump administration has proposed revisions to the Biden Rule. The current proposal would rescind greenhouse gas emissions targets as they related to fossil fuel-fired EGUs, or in the alternative declare carbon capture and sequestration technology. We believe it is unlikely that we will cease to have any regulatory requirements applicable to greenhouse gas emissions from fossil fuel-fired generating units, so CEI South used ACE as a proxy for carbon legislation in the reference case (see Figure 3-17). Since F.B. Culley 2 is planned for suspension in 2025, no ACE costs were included for this unit.

Figure 3-17 – ACE Proxy Cost

Unit	Total ACE Update Cost (2025$)
F.B. Culley 3	$32 Million

3.5.4. 316(b)

In 2014 EPA issued its final rule regarding Section 316(b) of the Clean Water Act which seeks to mitigate impacts to aquatic life from large water intake structures. The rule establishes requirements for Cooling Water Intake Structures ("CWIS") at existing fossil fuel-fired generating facilities and applies to the Culley generating facility which employs a once-through cooling water system. The 316(b) rule requirements are implemented through the facility's NPDES permit. Company is currently in the final stages of finalizing the selected technology and estimated costs for compliance at the Culley facility is included in the current IRP modeling scenarios as appropriate.

3.6. Tax Incentives

3.6.1. Inflation Reduction Act ("IRA") and One Big Beautiful Bill Act ("OBBBA")

The IRA was signed into law by President Biden on August 16, 2022. The $500 billion legislation was intended to mitigate the effects of climate change by offering numerous incentives to promote investment in clean energy production and included tax credits for households to offset energy costs. A substantial portion of the funding was directed toward reshaping the nation's energy infrastructure. Key provisions of the IRA included the extension of wind Production Tax Credits ("PTC"), the allowance of solar production tax credits, the continuance of solar Investment Tax Credits ("ITC"), funding for energy efficiency, the introduction of the ITC for stand-alone battery storage, and incentives for electric vehicle charging.

Vast portions of the IRA were eliminated with the passage of the OBBBA, signed into law on July 4, 2025. The legislation repeals most clean energy provisions and includes eligibility conditions that effectively disqualify clean energy projects that are not shovel-ready. The OBBBA includes a dual-condition eligibility test; a project must begin construction (start physical work or incur at least 5% of total project costs and maintain continuous progress) within 60 days of the bill's enactment and be placed into service by December 31, 2028. Projects that do not meet these criteria will no longer be eligible for the PTC or ITC. Additionally, the law removes consumer energy incentives for distributed energy adoption after 2025 and repeals electric vehicle tax credits after 2026. Credits for carbon capture and storage, clean fuels credit, and zero emissions nuclear power production credits remain in place.

These updates to the renewable tax credits were incorporated into the modeling assumptions based on the description of the scenarios. In the Reference Case and Alternate Reference Case, solar ITC and wind PTC eligibility expires at the end of 2029, while nuclear and storage resources retain their full credits through 2033, followed by declining values in 2034 and 2035. Figure 3-18 shows the updated tax credits included in the reference and alternate reference case scenarios.

Figure 3-18 – Reference and Alt Reference Scenario Tax Credits

		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%

For the High Regulatory and Alternate High Regulatory worldviews, the previous legislation governing tax credit eligibility was retained. Under these scenarios, solar and storage resources qualify for the full ITC through the end of 2032 and wind resources qualify for full PTC through 2029, with a reduced credit from 2030 through 2032. Figure 3-19 shows the pre-OBBBA tax credits that are included in the High Regulatory and Alternate High Regulatory scenarios.

Figure 3-19 – High Reg and Alt High Reg Scenario Tax Credits

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Solar	ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Storage	ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Wind	PTC	100%	100%	100%	100%	100%	100%	100%	100%	0%	0%	0%	0%

3.7. Resource Options

3.7.1. Current Resource Mix

Thermal generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics, outside of intermittent renewables, which do not have variable fuel costs. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack after intermittent renewables, which operate as available and typically unrelated to market prices and conditions. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. In general, units that cost less to run are dispatched before units that cost more.

F.B. Culley 3 has historically operated as a base load unit but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. F.B. Culley 3, CEI South's last coal unit that it plans to operate past 2025, more recently has operated more like an intermediate unit, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. CEI South's current peaking units have relatively high energy costs per kWh and are typically only started when energy demand exceeds 24/7 baseload capacity. Currently, CEI South's small gas turbines, units 3 and 4, are dispatched during these peak periods to assure reliability. These small peaking units may only run for a few hours and remain idle for long periods of time until called on. Most recently, CEI South has added two new combustion turbines and one solar array. These assets will provide necessary support for grid stability following the retirement of A.B. Brown coal units 1 and 2 in 2023.

3.7.1.1. Generation

CEI South's current and expected generation mix consists of approximately 1,807 MW of installed capacity. This capacity currently consists of approximately 360 MW of coal-fired generation from F.B. Culley 2 & 3. Following the suspension of F.B. Culley 2, which is scheduled for the end of 2025, the installed capacity of coal-fired generation in CenterPoint's fleet will drop to 270 MW. CEI South's existing generation also includes 624 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 397 MW of wind procured through Power Purchase Agreements ("PPAs"), 391 MW of solar (with 150 of that total coming from PPAs), and a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

3.7.1.2. Existing Resources

Figure 3-20 references both Installed Capacity ("ICAP") and Seasonal Accredited Capacity ("SAC"). Installed capacity is also referred to as nameplate capacity. Seasonal accredited capacity is the amount of capacity that can be relied upon to meet load during tight operating hours. MISO now uses SAC for planning purposes. The SAC accreditation recognizes all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year operating history and a weather normalized capability verification to determine the SAC accreditation of each unit. CEI South used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO seasonal planning reserve margin requirements (7.9% for summer, 14.9% for fall, 18.4% for winter, and 25.3 in spring[20]) in the current IRP. This information was utilized to help ensure all portfolios met MISO obligations on a seasonal basis.

Figure 3-20 – CEI South's Owned Generating Units (2026/2027 Planning Year)[21]

Unit	Installed Capacity (MW)	Summer - Seasonal Accredited Capacity (SAC - MW)	Fall - SAC (MW)	Winter -SAC (MW)	Spring - SAC (MW)	Primary Fuel	Initial Service Year
F.B. Culley 3	270	181.4	248.8	231.6	269.6	Coal	1973
A.B. Brown 3	80	67.4	72.1	91.7	75.8	Gas	1991
A.B. Brown 4	80	70.5	67.3	89.2	80.3	Gas	2002
A.B. Brown 5	232	209.1	195.1	183.5	195.1	Gas	2025
A.B. Brown 6	232	209.1	195.1	183.5	195.1	Gas	2025
Posey Solar	191	85.0	66.7	48.7	89.2	Sun	2025
Troy Solar	50	22.25	17.5	12.75	23.35	Sun	2021
Blackfoot	3	N/A	N/A	N/A	N/A	Landfill Gas	2009
Oak Hill Solar	2	N/A	N/A	N/A	N/A	Sun	2018
Volkman Rd. Solar	2	N/A	N/A	N/A	N/A	Sun	2018

[20] "Loss of Load Expectation Working Group (LOLEWG)". MISO Energy. October 24, 2024. https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf, Slide 2

[21] CEI South plans to place F.B. Culley 2 into suspension by December 31,2025.

3.7.1.2.1. Energy Efficiency

CEI South utilizes a portfolio of Demand Side Management ("DSM") programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. CEI South's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years.

Since 1992, CEI South has operated a Direct Load Control ("DLC") program called Summer Cycler which can reduce residential and small commercial air-conditioning and water heating electricity loads when needed during summer peak hours. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, this aging technology will be phased out over time. CEI South's Summer Cycler program has served CEI South and its customers well for more than three decades, but more recent technology is now making the program obsolete. Between 2010 and 2024, CEI South's DSM programs reduced demand by approximately 97,000 kW and provided annual incremental gross energy savings of approximately 521,000,000 kWh.

Figure 3-21 below outlines the estimated program penetration on an annual basis since CEI South programs began in 2010. Gross cumulative savings below, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 3-21 – Gross Cumulative Savings[22] [23]

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)	Gross Cumulative Savings (GW)	Percent of Sales Achieved (Cumulative)
2010	5,617	2.53	0.00051	0.04%
2011	5,595	19.40	0.00331	0.35%
2012	5,465	66.95	0.01212	1.23%
2013	5,459	128.64	0.02416	2.36%
2014	3,499	175.98	0.03215	5.03%
2015	3,224	202.82	0.03698	6.29%
2016	3,256	236.40	0.04222	7.26%
2017	3,281	268.86	0.04861	8.20%
2018	3,491	309.28	0.05624	8.86%

[22] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

[23] Statewide DSM programs ended in 2013. The drop in eligible sales is attributed to industrial customers opting out of DSM programs effective July 1, 2014.

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)	Gross Cumulative Savings (GW)	Percent of Sales Achieved (Cumulative)
2019	3,135	352.76	0.06455	11.25%
2020	3,176	398.16	0.07411	12.54%
2021	3,174	428.56	0.08102	13.50%
2022	3,209	454.79	0.08638	14.17%
2023	3,265	490.01	0.09265	15.01%
2024	3,285	521.50	0.09717	15.87%

3.7.1.2.1.1.1. 2025-2027 Plan Overview

Consistent with the 2022/2023 IRP, the framework for the 2025-2027 EE Plan was modeled at a savings level of 1.1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential, as well as commercial and industrial programs offered in 2025-2027. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2025-2027 EE Plan detail found in the *Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan*.

Residential Programs

- Residential Prescriptive
- Residential Midstream
- Home Energy Assessment
- In Store Discount
- Multi Family Energy Solutions
- Community Connections
- Residential New Construction
- Income Qualified Weatherization
- Energy Efficiency Store (Marketplace)
- Residential Behavior Savings
- Smart Cycle (“DLC Change Out”)
- Bring Your Own Thermostat (“BYOT”)
- Conservation Voltage Reduction (“CVR”) Residential

Commercial and Industrial Programs

- Commercial and Industrial Prescriptive
- Commercial and Industrial Midstream
- Commercial and Industrial Custom

- Small Business Energy Solutions
- Building Optimization
- Conservation Voltage Reduction ("CVR") Commercial

The 2025-2027 plan was included as an existing resource in the 2025 IRP and has an assumed average measure life of 13 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in *Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan*).

Figure 3-22 – Energy Efficiency Savings[24]

	2025		2026		2027	
Sector	Net kWH Energy Savings	Net kW Demand Savings	Net kWH Energy Savings	Net kW Demand Savings	Net =kWH Energy Savings	Net kW Demand Savings
Residential	13,259,256	7,818	14,814,287	8,854	14,732,977	7,874
C&I	19,224,000	2,528	21,344,251	2,982	21,570,750	2,757
Total	**32,483,256**	**10,345**	**36,158,538**	**11,836**	**36,303,727**	**10,631**

3.7.1.3. Demand Response

CEI South's tariff currently includes five Demand Response ("DR") programs:

- Direct Load Control Rider ("DLC"),
- Thermostat Load Control Rider ("TLC"),
- Two interruptible options for larger customers (Interruptible Contract Rider and Interruptible Option Rider),
- Aggregation Demand Response Rider ("ADR") and
- MISO Demand Response Rider.

Demand response programs allow CEI South to curtail load for reliability purposes. CEI South's MISO DR tariff and interruptible tariffs have no customers currently enrolled and registered with MISO. CEI South has recently contracted a third-party DR aggregator from the All-Source RFP to begin a DR aggregation program based on CEI South's customer load and industry demographics.

[24] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

3.7.1.3.1. Current DLC (SUMMER CYCLER)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, and electric water heating through radio-controlled load management receivers. Under the program, CEI South compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. CEI South can initiate a load control event for several reasons, including to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from MISO.

CEI South manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. CEI South also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2024, Cadmus predicted that the DLC Program was capable of generating approximately 8 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control during MISO load curtailment events during the summer season. This figure will continue to decrease over time with the increasing occurrence of switch failures.

Until recently, DLC switches have been the default choice for residential load control programs. CEI South has had a DLC program since the early 1990's and as of 2024 had approximately 16,000 residential customers with 22,250 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, CEI South has begun replacing DLC switches with smart thermostats, and the DLC program is closed to new customers as of February 13, 2025.

3.7.1.3.2. Current Interruptible Load

CEI South makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. CEI South previously had three customers who were participating for a total demand reduction of approximately 31 MW. MISO issued a curtailment on June 10, 2021. CEI South's largest interruptible customer at approximately 30 MW elected to no longer participate in the interruptible tariff after the event. CEI South worked with stakeholders to help update its interruptible tariffs to streamline language, open them up to a wider number of potential participants, and bring in line with MISO's on-going updates to the Load Modifying Resource ("LMR") rules to derisk this segment of resources. CEI South requested and received approval from the Commission to update these tariffs accordingly in its most recent rate case in Cause No. 45990. Even with these updates, CEI South still has no customers on the tariff registered as a resource with MISO. See section 3.7.1.3.4 for more information on how CEI South is working to partner with customers to maximize its demand response potential with this segment of C&I customers.

3.7.1.3.3. SMART THERMOSTATS

CEI South launched its pilot Smart Wi-Fi Thermostat program in 2016, by installing 2,000 smart Wi-Fi enabled thermostats in homes in its service territory. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while learning from occupant behavior/preference, adjusting Heating, Ventilation and Air Conditioning ("HVAC") settings. Evaluation results are showing significantly more load reduction delivered by smart thermostats than DLC switches. As such, CEI South has designed a program to replace switches with smart Wi-Fi thermostats, a strategic option for cost-effective load control. The Smart DLC Change-out program focuses on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, CEI South will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement. This change-out program is reflected in IRP modeling.

CEI South also launched the Bring your Own Thermostat program as a DR program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2025-2027 Plan provides for approximately 1,430 kW demand each year from the BYOT program based on approximately 1,300 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in the Thermostat Load Control program. By taking advantage of two-way communicating smart/Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. BYOT allows the utility to avoid the costs of hardware, installation and maintenance associated with transitioning to a smart thermostat. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events. Smart thermostat DR programs provide approximately 1 kW per thermostat in load reductions during a DR event.

3.7.1.3.4. Aggregation Demand Response

CEI South received approval to launch the Aggregation Demand Response program in Cause No. 45590. CEI South recently executed a contract with a third-party aggregator for C&I customers which allows the third-party aggregator to provide customers with a customized energy reduction plan specific to customer's needs based on customer type, such as the following: commercial office building, public school systems, and manufacturing. Aggregators often have the metering and controls technology to allow customers to see and manage their load reduction in real time.

CEI South has included 12 MWs in 2026 ramping up to 25 MWs in 2027 through 2045 based on a market potential analysis during the bidding process. CEI South is one of the first utilities to offer a new Aggregation program in Indiana within approximately the last 10 years. CEI South put this program in place in recognition of stakeholder interest, providing more optionality for C&I customers than CEI South alone can provide.

Aggregation provides long-term affordability by allowing participating customers to earn payments, improve resilience by allowing customers to receive advance notification of grid stability issues, protecting facilities from potential power outages, and supporting the community by helping to maintain reliable, low-cost energy. Aggregation allows for energy industry experts to work with customers to define strategies that leverage existing assets, manage enrollment and execution, and helps maximize revenue for participants.

3.7.2. Potential Future Resource Options

CEI South evaluated a broad range of supply-side technologies, including natural gas, renewable energy, storage technologies, and advanced nuclear. Operational inputs for all supply-side resources were developed from the technology assessment conducted by 1898 & Co., while capital costs were primarily sourced from CEI South's 2024 All-Source RFP results to reflect current market conditions. Where RFP data was not available, capital costs from the technology assessment were used, unless otherwise noted. Detailed information for the All-Source RFP and the technology assessment can be found in *Technical Appendix Attachments 2.1* and *2.2 (Confidential)*, respectively.

The following section details supply-side resource options including conversion opportunities at existing sites, followed by new natural gas, renewables, advanced nuclear, and storage technologies. Then, demand-side resources are outlined including Energy Efficiency and Demand Response programs. Finally, innovative rate designs are also considered.

3.7.2.1. Existing Site Conversions

CEI South evaluated two existing sites, F.B. Culley 3, and A.B. Brown 5 and 6, for potential conversion of existing units to provide additional capacity and energy to meet system needs. F.B. Culley 2 interconnection replacement was also explored in this IRP.

F.B. Culley 2:

At the F.B. Culley 2 site, three power generation technologies were evaluated: reciprocating engines, aeroderivative engines, and storage. The option to let the interconnection agreement at F.B. Culley 2 expire without reuse was also considered. The three resource types were selected based on available space at the site, available infrastructure, regulations on timing of a replacement resource, and CEI South's system needs. Operational parameters of all stated resource options, as well as the capital costs of the natural gas resources, were sourced from the technology assessment. The capital investment of a storage resource at the F.B. Culley 2 site was informed by the 2024 All Source RFP. The gas transportation costs included in all existing site conversions are for firm gas supply and were informed by vendor and internal estimates. Additional detail surrounding gas transportation costs is given in the *Technical Appendix Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)*. Figure 3-23 displays the operational and financial parameters for these potential resources.

Figure 3-23 – F.B. Culley 2 Potential Future Resource Options

Operating Characteristics and Estimated Costs	Reciprocating Engines	Aeroderivative Engines	Storage
Technology Description	Five 18-MW Engines	Two 50 MW Engines	4-Hour Lithium-Ion Storage
Base Load Net Output (MW)	91.5	104.4	90
Base Load Heat Rate (HHV Btu/MWh)	8,340	9,310	N/A
Capital Expenditures (2025$/kW)	$2,650	$3,440	$1,573
Fixed O&M (2025$MM/year)	$2.6	$3.2	$3.2
Gas Transportation Costs (2025$MM/yr)	$10.2	$9.6	N/A
Variable O&M (2025$/MWh)	$4.0	$0.90	N/A

F.B. Culley 3:

At the F.B. Culley 3 site, CEI South analyzed three potential operating pathways for the existing coal plant: continue operating on coal until retirement, convert to operating on natural gas, or co-fire with 40% natural gas. For the first two options, multiple implementation dates were studied. Potential retirement dates for F.B. Culley 3 included December 31, 2031, December 31, 2034, and beyond the planning horizon of this IRP. For conversion to natural gas, start dates of January 1, 2030 and January 1, 2035 were analyzed. Portfolios that included unit conversion also assumed a four-month outage prior to the conversion to allow for necessary construction. The co-fire pathway was modeled with only a single implementation date, primarily driven by the former Clean Air Act 111(d) rule. This includes beginning co-fire operation on January 1, 2030, followed by unit retiring by the end of 2038. These pathways are described in Figure 3-24. Converting F.B. Culley

3 to natural gas will likely result in the unit operating at a lower capacity factor compared to its current coal-fired operation, more similar to that of a peaking resource. The capital costs for this option were developed using vendor estimates, historical data, and internal calculations.

Figure 3-24 – F.B. Culley 3 Potential Future Resource Options

Operating Characteristics and Estimated Costs	Operate on Coal	Conversion to Natural Gas	Convert to Co-Fire
Description of Available Options	• Continue through 2045 • Retire on 12/31/2031 • Retire on 12/31/2034	• Start Gas Fired operation on 1/1/2030 • Start Gas Fired operation on 1/1/2035	• Start Co-Firing operation on 1/1/2030, followed by unit retirement on 12/31/2038
Base Load Net Output (MW)	270	270	270
Base Load Heat Rate (HHV Btu/MWh)	10,560	10,560	10,560
Gas Transportation Costs (2025$MM/yr)	N/A	$15.5MM	$8.9MM

A.B. Brown:

At the A.B. Brown site, the simple cycle gas turbines ("SCGT") placed in service in 2025 (A.B. Brown Units 5 and 6) were evaluated for conversion to a 2x1 combined cycle gas turbine (CCGT), which would improve thermal efficiency, increase generation capacity, and transition the primary use of the facility to be a baseload resource. In this configuration, the exhaust heat from each existing combustion turbine would be captured by a Heat Recovery Steam Generator ("HRSG") which converts the waste heat into steam. This steam then drives a steam turbine generator to produce additional electricity without additional fuel input. Furthermore, this combined cycle configuration was investigated with and without duct firing. In the duct-fired CCGT, natural gas burners are installed in the HRSG to inject supplemental fuel directly into the exhaust steam, raising the temperature and causing the production of more steam. This design provides approximately 150 MW of additional output compared to the non-duct fired configuration. Both options were included to evaluate the tradeoff between increased output and higher capital investments, fuel usage and slightly lower efficiency when operated in this mode. Two implementation dates were considered for this conversion, with the unit being fully operational as a combined cycle at the start of 2030 or 2034. Figure 3-25 depicts the operational and financial parameters of this option.

Figure 3-25 – A.B. Brown Potential Future Conversion Options

Operating Characteristics and Estimated Costs	2x1 F Class SCGT to CCGT Conversion, Unfired	2x1 F Class SCGT to CCGT Conversion, Fired
Base Load Net Output (MW)	735	734
Base Load Heat Rate (HHV Btu/MWh)	6,430	6,440
Duct Fired Net Output (MW)	N/A	893
Duct Fired Heat Rate (HHV Btu/MWh)	N/A	6,830
Capital Expenditures (2025$/kW)	$1,050	$950
Fixed O&M (2025$MM/yr)	$6.2	$6.2
Gas Transportation Costs (2025$MM/yr)	$37.7	$37.7
Variable O&M (2025$/MWh)	$1.5	$1.5

3.7.2.2. Natural Gas

Natural gas power plants are characterized by igniting natural gas and transforming the heat generated from combustion into electrical energy. In addition to the natural gas projects at existing sites, CEI South evaluated a wide range of natural gas technologies including peaking resources such as simple-cycle turbines and reciprocating engines, and intermediate and baseload options such as combined cycle units. This wide range of available natural gas-powered alternatives allow for the evaluation of the tradeoffs between cost effectiveness, reliability, and environmental sustainability.

3.7.2.3. Simple Cycle Gas Turbines

SCGTs utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies and relatively low capital costs. See Figure 3-26 for further details on the simple cycle gas turbine technologies evaluated.

To aid in the evaluation of SCGT, technology estimates were developed to represent the natural gas pipeline costs to supply firm gas service to the unit. An average pipeline cost (in dollar per MW) was developed from the F.B. Culley and A.B. Brown site estimates and then applied to the maximum capacity of all evaluated generic thermal resources. More detail on the estimated gas transportation costs is given in the *Technical Appendix Attachment 3.5 Gas Pipeline Cost Estimate (Confidential)*.

Figure 3-26 – Simple Cycle Gas Turbine Technologies

Operating Characteristics and Estimated Costs	1xF-Class SCGT	1xJ-Class SCGT
Base Load Net Output (MW)	235	426.4
Base Load Net Heat Rate (HHV Btu/kWh)	9,930	8,940
Base Project Costs (2025$/kW)	$1,520	$1,190
Fixed O&M Costs (2025$MM/year)	$2.5	$2.6
Gas Transportation Costs (2025$MM/year)	$17.7	$32.2
Variable O&M (2025$/MWh)	$0.9	$1.2

3.7.2.4. Combined Cycle Gas Turbines

CCGTs utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator and to also use the hot exhaust gases from the gas turbine to produce steam in a HRSG. This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, seven different configurations were evaluated: a 1x1 F class (unfired and fired), 2x1 G/H class (unfired and fired), 1x1 J class (unfired), and 2x1 J class (unfired and fired), as shown in Figure 3-27 and Figure 3-28. A 1x1 CCGT is configured with one gas turbine and one steam turbine where a 2x1 CCGT is configured with two gas turbines and one steam turbine. General Electric ("GE") turbines were used as representative CCGT technologies for the operational and financial parameters. The F class is based on the GE 7FA.05 turbine, the J class is based on the GE 7HA.03, and the G/H class is based on the GE 7HA.01 turbine.

Figure 3-27 – Combined Cycle Gas Turbine Technologies (Unfired Configuration)

Combined Cycle Gas Turbines - Unfired				
Operating Characteristics and Estimated Costs	**1x1 F-Class**	**2x1 G/H-Class**	**1x1 J-Class**	**2x1 J-Class**
Base Load Net Output (MW)	366	848	620	1,254
Base Load Net Heat Rate (HHV Btu/kWh)	6,470	6,260	6,150	6,080
Base Project Costs (2025$/Unfired kW)	$2,271	$1,961	$2,039	$1,695
Fixed O&M Costs (2025$MM/year)	$5.9	$6.7	$6.1	$6.8
Gas Transportation Costs (2025$MM/year)	$27.5	$63.9	$46.7	$94.6
Variable O&M (2025$/MWh)	$1.6	$1.6	$1.6	$1.5

Figure 3-28 – Combined Cycle Gas Turbine Technologies (Fired Configuration)

Combined Cycle Gas Turbines - Fired			
Operating Characteristics and Estimated Costs	**1x1 F-Class**	**2x1 G/H-Class**	**2x1 J-Class**
Base Load Net Output (MW)	365	847	1,244
Total Duct-Fired (Peaking) Net Output (MW)	445	1,034	1,454
Base Load Net Heat Rate (HHV Btu/kWh)	6,490	6,260	6,120
Total Duct-Fired Heat Rate (HHV Btu/kWh)	6,843	6,682	6,569
Base Project Costs (2025$/Fired kW)	$2,518	$2,070	$1,808
Fixed O&M Costs (2025$MM/year)	$5.9	$6.7	$6.8
Gas Transportation Costs ($MM/year)	$33.5	$78.0	$109.7
Variable O&M ($/MWh)	$1.6	$1.6	$1.5

3.7.2.5. Aeroderivative and Reciprocating Engines

Aeroderivative and reciprocating internal combustion engines represent smaller-scale, highly flexible natural gas technologies. Aeroderivative turbines are adapted from jet engine technology, while reciprocating engines are most technologically similar to the engine found in a car. These technologies are well-suited to provide peaking and balancing services during periods of system stress or low renewable output. Both engine types have smaller unit sizes, fast start-up times, and strong operational flexibility when compared to large heavy-frame gas plants. Figure 3-29 explains the operating and financial characteristics of these natural gas units.

Figure 3-29 – Aeroderivative and Reciprocating Engines

Operating Characteristics and Estimated Costs	Aeroderivative Engines	Reciprocating Engines
Base Load Net Output (MW)	52 MW (single engine)	110 MW (six 18-MW engines)
Base Load Net Heat Rate (HHV Btu/kWh)	9,310	8,340
Base Project Costs (2025$/kW)	$3,440	$2,650
Fixed O&M Costs (2025$MM/year)	$2.1	$3.1
Gas Transportation Costs (2025$MM/year)	$3.9	$8.3
Variable O&M ($/MWh)	$0.90	$4.0

3.7.2.6. Renewables

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic ("PV"), and hydroelectric. Our base assumptions for renewable tax credits reflect the updates specified in the OBBBA, including the end of solar and wind tax credits by 2030. Wind resources were modeled to include Production Tax Credits, while solar resources included discounts for the Investment Tax Credit. Under the IRA solar resources have the option to choose between the investment tax credit and the production tax credit. Based on the assumed capacity factor of solar resources, the investment tax credits are anticipated to provide more value and therefore were used in the model.

3.7.2.6.1. Wind

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 3-30 for further details on wind technologies evaluated. Aside from the hybrid storage price, the following assumptions were based on the 1898 & Co. technology assessment.

Figure 3-30 – Wind Technologies

Operating Characteristics and Estimated Costs	Wind	Wind + 4-Hour Storage
Base Load Net Output (MW) + (MW for Storage)	200	200 + 100
Base Project Costs (2025$/kW) + ($/kW for Storage)	$2,194	$2,194 + $1,436
Fixed O&M Costs (2025$MM/year)[25]	$10.5	$10.5 + $3.3
Annual Capacity Factor	37%	37%

[25] Variable O&M costs are included in the Fixed O&M estimate in this table.

3.7.2.6.2. Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a relatively mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar PV technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 3-31 for further details on the solar PV technologies evaluated. Base project costs are informed by the 2024 All Source RFP data where available. Where current market pricing was not available, the technology assessment provided a starting point for cost estimates, which was then tailored to current market conditions as seen in the 2024 All Source RFP.

Figure 3-31 – Solar Technologies

Operating Characteristics and Estimated Costs	10 MW Solar PV	100 MW Solar PV	100 MW Solar PV + 4-Hour Storage
Base Load Net Output (MW) + (MW for Storage)	10	100	100 + 50
Base Project Costs (2025$/kW) + (2025$/kW for Storage)	$2,560	$2,351	$2,504 + $1,626
Fixed O&M Costs (2025$MM/year)[26]	$0.1	$1.2	$1.2 + $1.8

3.7.2.6.3. Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 3-32 for further details on the hydroelectric technology evaluated.

[26] Variable O&M costs are included in the Fixed O&M estimate.

Data from a U.S. Army Corps of Engineers report was used to determine the economically feasible output from the Newburgh and John T. Myers dams located locally on the Ohio River. This report showed that, when taking economics into consideration, both dams combined had an average potential output near 50 MW, which was consistent with tech assessment data used in the analysis. A separate publication from the U.S Army Corps of Engineers showed the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 3-32 – Hydroelectric Technologies

Operating Characteristics and Estimated Costs	John T. Myers	Newburgh
Base Load Net Output (MW)	36	22
Base Project Costs (2025$/kW)	$6,901	$6,901
Fixed O&M Costs (2025$MM/year)	$3.8	$2.3

3.7.2.7. Storage

In addition to storage resources paired with renewable technologies, standalone storage was evaluated in this IRP. Short duration Lithium-Ion batteries as well as more nascent long duration technologies were considered. These are summarized in Figure 3-33 and Figure 3-34.

Lithium-ion technology represents a significant majority of utility scale, stationary energy storage projects being developed and installed in the current market. It is the most commercially and technically mature battery storage solution in today's market and is commonly the most cost-effective option for grid-scale applications/use cases with a 1-4 hour discharge duration at rated power. Cost and performance information for these resources are informed by the 2024 All-Source RFP where data was available. Where current market pricing was not available, the technology assessment provided a starting point for cost estimates, which was then tailored to current market conditions as seen in the 2024 All Source RFP.

In effort to consider a wide range of resources, additional emerging energy storage options were also considered as long duration (>4 hours) storage. There are numerous technologies of varying commercial and technical maturity, and while CEI South recognizes the desire for technology diversity, two representative technologies were selected to represent the broader category of long duration energy storage ("LDES"). Compressed Air Energy Storage ("CAES") is a maturing technology that is suitable for large, utility scale projects. While CAES will be limited in implementation depending on certain geologic characteristics, it generally represents the lower end of today's LDES capital cost range and is therefore a representative technology for resource planning. Additionally, following requests from stakeholders, iron-air energy storage technology was also included in this analysis. The cost and performance estimates for the 100 MW/ 100 Hour storage technology is shown in Figure 3-34.

Figure 3-33 – Lithium-Ion Energy Storage

Operating Characteristics and Estimated Costs	Lithium Ion 50 MW / 200 MWh	Lithium Ion 100 MW /400 MWh	Lithium Ion 100 MW /800 MWh
Base Load Net Output (MW)	50	500	100
Storage Duration (hours)	4	4	8
Round-Trip Cycle Efficiency	85%	85%	85%
Base Project Costs (2025$/kW)	$2,461	$2,273	$4,067
Fixed O&M Costs (2025$MM/year)[27]	$2.0	$3.5	$6.3

Figure 3-34 – Emerging Energy Storage Technologies

Operating Characteristics and Estimated Costs	Compressed Air Representative Technology	Iron Air Representative Technology
Base Load Net Output (MW)	100	100
Storage Duration (hours)	10	100
Round-Trip Cycle Efficiency	68%	34%
Base Project Costs (2025$/kW)	$5,020	$2,840
Fixed O&M Costs (2025$MM/year)[27]	$4.2	$5.0

3.7.2.8. Advanced Nuclear

Nuclear power generation technology has been a dependable, carbon-free power resource in the United States for many decades. In a nuclear power plant, nuclear fission, or the splitting of atoms, occurs. This process creates heat energy which is used to generate steam and spin a turbine, which in turn produces electricity. The nuclear technology considered in this evaluation is a small modular reactor ("SMR") design, which is characterized by compact reactor modules that can be deployed individually or in groups to match system needs. The design incorporates passive safety systems, simplified plant configurations, and high thermal efficiency, which enable lower operating costs and enhanced safety as compared to traditional nuclear generators. The assumed economic and operational data can be found in Figure 3-35.

[27] Variable O&M costs are included in the Fixed O&M estimate.

Although commercial SMR projects are still under development, evaluating a nuclear option provides insight into potential long-term strategies for reliable, sustainable power generation. In the near-term, CEI South views the technology as a future-facing resource rather than a near-term build candidate. For the purposes of this IRP, it is assumed that 2035 is the earliest possible in-service date for this technology.

Figure 3-35 – Advanced Nuclear Technology

Operating Characteristics and Estimated Costs	Nuclear
Base Load Net Output (MW)	100
Base Load Net Heat Rate (HHV Btu/kWh)	11,580
Base Project Costs (2025$/kW)	$15,812
Fixed O&M Costs (2025$MM/year)	$21.6MM
Variable O&M Costs (2025$/MWh)	$2.8

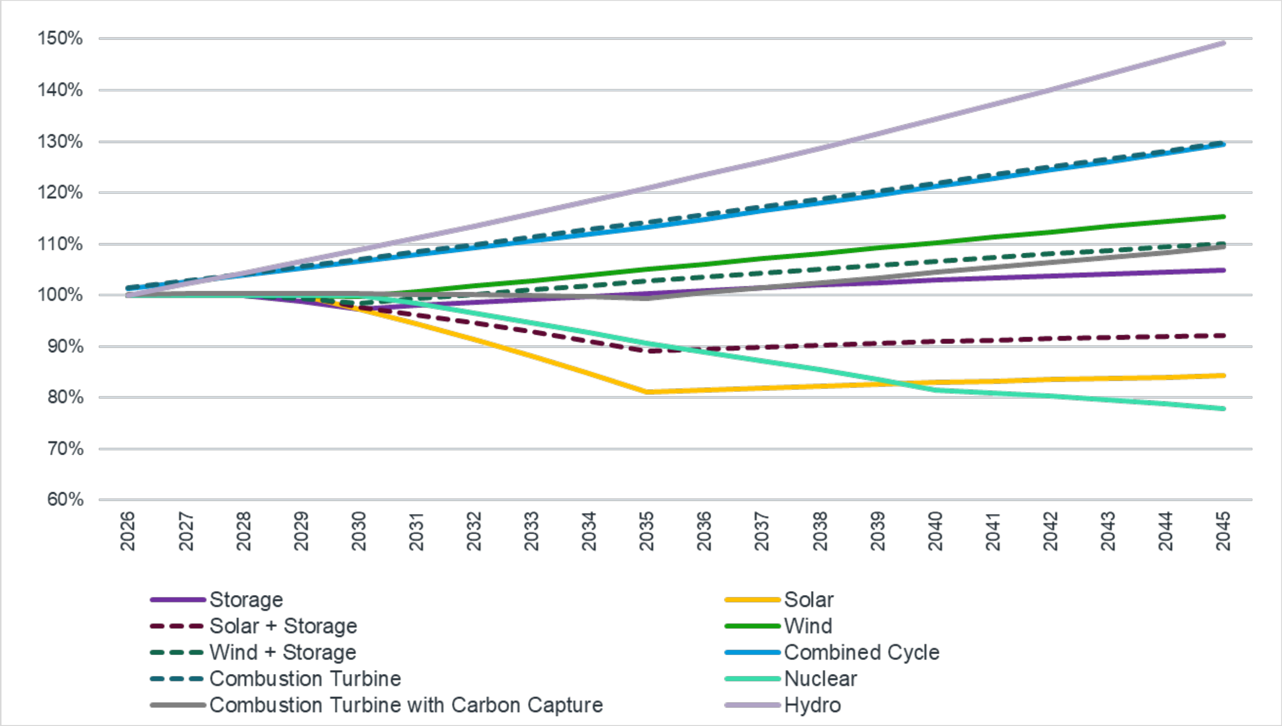
3.7.2.9. Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2025 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 3-36.

Technologies whose capital costs do not decline significantly over the IRP time period, such as wind, natural gas, and coal are generally more mature, while technologies such as advanced nuclear, solar, and hybrid solar plus storage are less mature and expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies for nuclear, solar, and hybrid solar plus storage are expected to decrease capital costs over time. Due to uncertainty associated with these less mature technologies, CEI South relied upon information collected as part of the 2024 All Source RFP as well as cost curves provided by the NREL in their 2024 Annual Technology Baseline ("ATB") Workbook[28] to help project capital costs over the study period.

[28] The NREL ATB Excel workbook can be found here: https://atb.nrel.gov/electricity/2024/data. Capital cost curves were pulled from the "CAPEX ($/kW)" of each included technology.

Figure 3-36 – Forward Looking Capital Cost Curves– Forward Looking Capital Cost Curves



3.7.2.10. Energy Efficiency

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of DSM options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:
> (1) Rate design as a resource in meeting future electric service requirements.
> (2) Demand-side resources. For potential demand-side resources, the utility shall include the following:
> (A) A description of the potential demand-side resource, including its costs, characteristics, and parameters.
> (B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined.
> (C) The customer class or end-use, or both, affected by the demand-side resource.

(D) Estimated annual and lifetime energy (kWh) and demand (kW) savings.
(E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements.
(F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers."

In addition, this process aligns with IAC 8-1-1.5-3 which requires energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

3.7.2.10.1. DSM Market Potential Study

The first step in the process is a Market Potential Study ("MPS"). A key purpose of an energy efficiency MPS is to provide energy efficiency planners, decision makers and interested stakeholders with a roadmap to the best opportunities for energy efficiency savings opportunities in the residential, commercial and industrial customer classes. "Energy efficiency potential studies are an effective tool for building the policy case for energy efficiency, evaluating efficiency as an alternative to supply side resources and formulating detailed program design plans. They are typically the first step taken by entities interested in initiating or expanding a portfolio of efficiency programs and serve as the analytic basis for efforts to treat energy efficiency as a high-priority resource equivalent with supply-side options."[29] The results of a potential study pinpoint the energy efficiency measures having the greatest potential for energy savings and identifies the measures that are the most cost effective. Program administrators, regulators and stakeholders can use the results of potential studies to determine the types of programs that should be implemented and how much to invest in energy efficiency as a resource. Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: societally, all customers, the program administrator, program participants and utility rates.

CEI South's MPS completed in 2025 was utilized to both to inform the IRP and support the development of a DSM Action Plan for CEI South, see *Technical Appendix Attachment 3.6 2025 DSM Market Potential Study*. The study included a comprehensive review of current

[29] "Guide for Conducting Energy Efficiency Potential Studies"; Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc.; https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf ; November 2017; page ES-1

programs, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study leveraged new primary market research from the *Technical Appendix Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey* in the CEI South service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. New primary market research from the 2025 study was also leveraged to estimate customer willingness to participate in energy efficiency programs at different incentives levels and targeted end-uses.

Technical potential is the maximum energy efficiency available, assuming cost and market adoption of a technology are not a barrier. Economic potential is the subset of technical potential that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the energy efficiency measure. While some may contend the full technical or economic potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic as historical evidence has shown not all customers will adopt a given technology for reasons that range from aesthetic preferences, lack of information about energy efficiency measures, lack of access to capital to perceived comfort concerns. Rather, the potential modeled in the IRP should reflect some consideration of achievability.

To that end, achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints and other barriers the “program intervention” is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- **Maximum Achievable** Potential estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- **Realistic Achievable** Potential estimates achievable potential with CEI South paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

It is important to also note the estimates of potential considered in the MPS (and ultimately, in the IRP) exclude potential savings from customers who are eligible and have chosen to actively opt-out of participating in CEI South's energy efficiency programs. In the CEI South service area, approximately 5% of commercial energy sales and 72% of industrial energy sales are associated with customers who have elected to opt-out.

In addition to the energy efficiency potential study, a demand response potential study was also conducted. The methodological approach to the demand response potential study closely mirrored the energy efficiency analysis, with an assessment of the calculation of the demand response technical, economic, and achievable potential. The demand response study analyzed existing programs, such as the Smart Cycle and Residential BYOT programs, as well as potential new programs, such as DR Aggregation, DLC Grid-Enabled Water Heating, DLC Electric Vehicle, Battery Storage, Commercial BYOT, and Critical Peak Pricing rates. The demand response study shows the amount of potential demand that could be realized if customers shift their electric usage from on-peak to off-peak periods.

3.7.2.10.2. Energy Efficiency – IRP Reference Case

Energy Efficiency for the 2025 through 2027 IRP years were informed directly from CEI South DSM Settlement Agreement (2025-2027). These years of energy efficiency were treated as a "going-in" resource in the IRP. For the remaining IRP years (2028-2045), CEI South used the realistic achievable potential identified in the MPS as the starting point for energy efficiency to be modeled in the IRP.

CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team initially provided the energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2025-2027 EE levels, the 2028-2045 income-qualified bundle was also treated as a 'going-in' resource as the high costs of program delivery would likely prevent its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2028-2030, 2031-2033, and 2034-2045 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the initial sector-level bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. 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 CEI South's programs. Net savings were calculated by applying CEI South's most current Net to Gross ("NTG") ratios to the MPS estimates of gross achievable savings.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on peak system line loss rate of 8.4% to convert savings from the meter level up to the generator level. Figure 3-37 provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided transmission and distribution ("T&D") benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

3.7.2.11. Demand Response

CEI South, after working with stakeholders, expanded the number of DR bundles to be included for selection in the IRP Reference Case, from five bundles in the 2022/2023 IRP to thirteen bundles. In the 2025 IRP, to align with MISO's new seasonal structure, cumulative demand MW savings were calculated per the four seasons (Summer, Winter, Spring and Fall).

CEI South included two fixed bundles representing CEI South's DR capabilities for DLC switches on residential air conditioning units and hot water heaters in the CEI South service area. Over the IRP time frame, CEI South anticipates replacing existing DLC switches with smart thermostats that integrate DR capabilities (via the Smart Cycle Program). As CEI focuses on converting switches to smart thermostats, the estimated annual DR savings for the fixed residential air conditioner switch bundle drop from approximately 1.45 MW in 2028, to 0.13 MW by 2045. The estimated annual impacts for the fixed residential water heater switch bundle of DR are approximately 0.41 MW in 2028, decreasing to 0.05 MW by 2045.

Bundles three and four, both selectable resources, represent DR saving capabilities for CEI South's residential DR-enabled smart thermostats. The third bundle represents the Smart Cycle Program, anticipating DR savings from replacing DLC switches with smart thermostats. DR capabilities within the Smart Cycle bundle represents 13.68 MW of peak reduction capabilities in 2028 decreasing to 12.74 MW in 2045. The fourth bundle represents DR savings for customer self-installed DR-enabled smart thermostats in our BYOT program. This bundle represents an additional 12.85 MW of peak reduction capabilities in 2028 increasing to 17.85 MW by 2045.

A fifth bundle also represents DR savings for smart thermostats, but this is a new bundle focused on the commercial sector. CEI South commercial customers wanting to enroll their BYOT thermostats could achieve approximately 0.37 MW in 2028, as historical devices would not yet contribute to DR savings. As participation increases, this bundle shows a potential of 3.56 MW in 2045.

Bundles six and seven, consists of DR savings attributable to a time of use ("TOU") rate option with a critical peak price ("CPP") rate. This program is expected to start in 2026 and build slowly a pilot program through 2030. The sixth bundle, representing residential DR potential from TOU with CPP is expected to achieve approximately 0.57 MW in 2028 and increase to 5.71 MW in 2045. The seventh bundle, accounting for commercial DR savings from TOU with CPP, can achieve around 0.24 MW in 2028 and 2.07 MW in 2045.

Bundles eight and nine, both selectable resources, are new inputs in the 2025 IRP. These bundles represent DR savings for residential and commercial grid-enabled water heaters. Residential grid-enabled water heaters represent an additional 0.63 MW of peak reduction capabilities in 2028 and increases to 5.7 MW in 2045. Commercial grid-enabled water heaters represent an additional 0.31 MW in 2028 and increases to 2.6 MW in 2045.

Per stakeholder requests, two more new bundles for this IRP represent DR savings from EV chargers. One bundle represents residential DR achievable potential and the other represents commercial DR capabilities. Bundle ten, residential EV, represents 0.02 MW in 2028 and increases to 1.2 MW in 2045. The eleventh bundle shows there is very little DR savings potential in CEI South's territory for commercial EV charging, with 0.00003 MW in 2028 increasing to 0.001 MW in 2045.

The final two bundles, also new selectable resources per stakeholder requests, represent inputs for residential battery and commercial battery DR saving potential. The residential battery DR saving inputs provided in bundle twelve, represent 0.03 MW in 2028 and increase to 0.68 MW in 2045. The commercial battery DR potential in bundle thirteen represents an additional 0.01 MW in 2028 and increases to approximately 0.37 MW in 2045.

3.7.2.12. DSM Resources Optimization Process

Energy Efficiency for the 2026 and 2027 IRP years were informed directly from CEI South DSM Plan (*Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan)* approved in Cause No. 46100. These years of energy efficiency were treated as a "going-in" resource in the IRP. For the remaining IRP years (2028-2045), CEI South used the achievable potential identified in the MPS[30] as the starting point for energy efficiency to be modeled in the IRP.

CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team provided energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2026/2027 EE levels, the 2028-2045 income-qualified bundle was also treated as a 'going-in' resource as the high costs of program delivery would likely limit its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2028-2030, 2031-2033, and 2034-2045 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. The first adjustment converted the 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 CEI South's programs. Net savings were calculated by applying CEI South's most current NTG ratios to the MPS estimates of gross achievable savings.

30 The IRP inputs used the Enhanced RAP identified in the MPS for the C&I sector, and the RAP for the residential / income-qualified sectors.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on a multiplier of 1.092 to convert savings from the meter level up to the generator level. The table below provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided T&D benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

Figure 3-37 – MPS versus Initial IRP Bundles Comparison – Sum of Incremental MWh

	Vintage 1: MPS	Vintage 1: IRP	Vintage 2: MPS	Vintage 2: IRP	Vintage 3: MPS	Vintage 3: IRP
Residential	46,733	45,343	58,227	55,643	310,420	287,399
C&I	76,079	69,786	75,949	69,666	260,052	238,540
IQW	4,640	4,458	6,284	5,895	31,734	29,130

Following an early review of the residential and commercial/industrial energy efficiency savings and costs inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2), and low/mid cost measure (Tier 1) across each vintage time-series due to concerns that an aggregate residential sector bundle would not get selected. Residential behavioral energy efficiency savings were included in the Tier 1 bundle. Figure 3-38 summarizes the final bundle incremental savings for energy efficiency and associated levelized utility cost per lifetime savings.

In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-use mix reflected in each EE resource bundle were provided to CEI South to permit the IRP model 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 EE sector and vintage bundle.

Figure 3-38 – Annual MWh EE Savings and Levelized Costs per Lifetime MWh Saved by Bundle

EE Bundles	Enhanced C&I		Res Tier 1 + HER		Res Tier 2		IQW		IQW_HEAR	
	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh
2028	22,839	$37.87	10,879	$30.27	2,708	$84.06	1,042	$166.76	293	$332.49
2029	23,439	$38.72	11,893	$31.52	3,257	$85.49	1,120	$174.99	368	$339.69
2030	23,507	$39.63	12,849	$32.69	3,757	$87.40	1,185	$184.76	451	$347.49
2031	24,198	$40.73	13,495	$33.93	4,222	$89.49	1,319	$201.48	539	$355.87
2032	23,406	$41.66	13,938	$35.04	4,673	$91.91	1,347	$213.36	628	$364.92
2033	22,062	$42.43	14,157	$36.20	5,159	$94.47	1,349	$226.10	712	$374.82
2034	23,008	$44.03	15,372	$34.12	6,097	$94.80	1,411	$244.11	786	$385.39
2035	21,998	$45.14	15,487	$35.20	6,499	$97.62	1,377	$257.84	849	$396.47
2036	20,511	$45.88	15,293	$36.12	6,854	$100.57	1,315	$271.91	899	$407.87
2037	19,500	$47.06	15,061	$37.04	7,131	$103.51	1,327	$289.87	936	$419.72
2038	20,898	$49.15	16,246	$36.40	7,624	$106.04	1,565	$268.04	962	$431.29
2039	20,087	$49.89	17,636	$37.43	7,846	$108.39	1,581	$275.56	981	$442.33
2040	19,772	$51.05	17,724	$38.03	7,998	$111.09	1,628	$287.22	993	$452.74
2041	18,773	$51.85	17,550	$38.81	8,004	$113.26	1,569	$295.52	1,000	$462.96
2042	17,685	$52.27	17,369	$39.67	7,996	$115.36	1,520	$303.39	1,005	$472.25
2043	19,434	$50.86	17,234	$40.50	7,904	$118.38	1,539	$316.34	1,000	$480.82
2044	18,923	$51.04	16,825	$40.97	7,639	$121.56	1,477	$322.91	997	$488.83
2045	17,951	$51.39	16,484	$41.61	7,528	$123.45	1,419	$329.24	994	$497.27

3.7.2.13. DSM Improvements Based on Stakeholder Feedback

Review of prior comments from stakeholders and robust stakeholder discussion led to several improvements to DSM modeling since the 2022/2023 IRP. The model has been allowed to make multiple decisions over the 20-year period. The model selects DSM for two three-year periods beginning in 2028 and 2031 and then evaluates the remaining years beginning in 2034 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences and resource needs across the short, mid and long run.

The characterization of the EE and DR bundles included in the IRP modeling was based on a collaborative process with the stakeholders. This led to re-evaluating the sector level budling approach included in the 2022/2023 IRP. CEI South bundled the measures by sector for residential and non-residential consistent with the 2022/2023 IRP to account for high savings behavioral based efficiency measures to be bundled with low to medium cost measures to help ensure the maximum amount of realistic achievable potential was economically selected. CEI South included the income qualified bundle and added an income qualified HEAR bundle to account for savings through the Indiana Energy Saver program (which will occur outside of DSM filings). CEI South bundled C&I sector savings at an enhanced realistic achievable potential, which allows incentives for some measures to be decreased while increasing incentives for measures that would deliver additional adoption and savings. An improvement to the 2022/2023 IRP was adding more emerging technology measures to be included in bundles across all sectors. Additional sector and end-use specific hourly load shapes were included to more accurately estimate the timing of the energy efficiency impacts throughout the year. Also, based on feedback in the Director's report and working with the OSB, DR bundles were expanded to include six (6) additional DR products as selectable resources even though most were not cost-effective in the MPS.

CEI South also modeled Aggregation as the program is currently being implemented. CEI South explored options and strategies for C&I customers to participate in the program. The aggregator will utilize DR products based on customers industry type and will deploy appropriate curtailment strategies such as process controls and equipment. The aggregator has implemented DR strategies such as lighting controls, thermal energy storage, irrigation controls across utility partners nationwide.

Pricing options modeled in the IRP were based on an opt-in time of use and critical peak pricing design that aligns with CEI South's current pilot program, assuming a broader role out of the rate. Peak time rebates were not modeled as the evaluation, measurement and verification of savings is complex and is specific to each individual customer. Further, such a design would cause CEI South to undergo significant and costly changes to the billing system. Figure 3-39 contains a summary of EE & DR bundles modeled in the 2022/2023 and 2025 IRP with a description of enhancements.

Figure 3-39 – EE and DR Bundle Comparison and Enhancements

Resource Type	2022/2023 Bundles	2025 Bundles	Enhancement
Energy Efficiency	Res Tier 1	Res Tier 1 + Behavioral	Bundled Behavioral with Low/Medium cost Tier 1 to capture large savings high-cost measure
Energy Efficiency	Res Tier 2	Res Tier 2	Introduced an expanded emerging tech measure list for consideration
Energy Efficiency	Res Behavioral		
Energy Efficiency	Res Income Qualified	Res Income Qualified	
Energy Efficiency		Res Income Qualified HEAR	Introduced new bundle to capture impacts of OED IN Energy Saver program, will not be included in utility EE programs
Energy Efficiency	Non-Res Enhanced RAP	Non-Res Enhanced RAP	Modeled the enhanced RAP, where some incentives were decreased for measures and other were increased to drive participation
Demand Response	Res Switches	Res AC Switch	Modeled AC Switch as a "going in" resource, water heater switches were modeled as a separate DR product
Demand Response		Res WH Switch	
Demand Response	Res Smart Cycle & BYOT	Res Smart Cycle	Modeled Smart Cycle as a selectable resource, BYOT thermostats were modeled as a separate DR product
Demand Response		Res BYOT	Bundle was expanded to capture March through November instead of summer only season of June through August
Demand Response		Res WH Grid	Created a new bundle based on stakeholder feedback for grid-enabled water heaters, primarily managed through Wi-Fi
Demand Response		Res EV	Created a new electric vehicle managed charging DR resource using updated saturation & adoption rates based on OSB feedback
Demand Response		Res Battery	Created a new Battery Storage DR resource using updated saturation & adoption rates based on OSB feedback. Ran at multiple incentive levels
Demand Response	Res Rates	Res TOU CPP	Modeled a specific Time-of Use and Critical Peak Pricing resource that aligns with pilot approval in Cause No. 45990

Resource Type	2022/2023 Bundles	2025 Bundles	Enhancement
Demand Response	Non-Res BYOT	Non-Res BYOT	Bundle was expanded to capture March through November instead of summer only season of June through August
Demand Response		Non-Res WH Grid	Created a new bundle based on stakeholder feedback for grid-enabled water heaters, primarily managed through Wi-Fi
Demand Response		Non-Res EV	Created a new electric vehicle managed charging DR resource using updated saturation & adoption rates based on OSB feedback
Demand Response		Non-Res Battery	Created a new Battery Storage DR resource using updated saturation & adoption rates based on OSB feedback. Ran at multiple incentive levels
Demand Response	Non-Res Rates	Non-Res TOU CPP	Modeled a specific Time-of Use and Critical Peak Pricing resource that aligns with Residential pilot approval in Cause No. 45990. Modeling will help inform if TOU & CPP rates are selected for Non-Res
Demand Response	Aggregation	Aggregation	Modeled as a "going in" resource, Aggregation received approval in Cause. No. 45990. CEI South is in the beginning stages of implementing the program and expect 12.5 MWs in 2026 and 25 MWs for 2027-2045

3.7.2.14. Innovative Rate Design

CEI South included innovative rate design in its Preferred Portfolio in its 2022/2023 IRP and the 2025 IRP. Following the IRP, CEI South proposed a CPP with Time of Use (“TOU”) pilot in its recent rate case in Cause No. 45990. The Commission approved the pilot, and CEI South has been actively working to develop the program that is set to begin in Q2 2026.

CEI South’s approved CPP TOU pilot provides an economic price signal for participating customers to lower their energy usage during peak times through rates. The TOU rate will be available to participating customers in the CEI South pilot between June and September with higher prices during the day and lower prices during nights and weekends. Most likely during times of highest usage, CEI South may call a CPP event, similar to a demand response event where prices are raised to the extent that a reduction in demand is induced. The Automated Metering Infrastructure provides the backbone for this program.

CEI South utilized its continuous improvement and project management teams to work collaboratively with business units to build out the necessary infrastructure to support the pilot. CEI South will work through the pilot over the next one to two years in the hopes of expansion, if successful. An expansion of the CPP TOU pilot is included within this IRP, utilizing indicative amounts developed in its most recent Market Potential Study. The CPP pilot will help inform the potential expansion of an innovative rate design for the commercial sector, included in this IRP.

3.8. Transmission Planning & Distribution Planning

CEI South continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of CEI South's planning process can be summarized as follows:

- Developing an electric system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet CEI South customers' needs during normal conditions and during a system contingency (loss of a system asset) or set of contingencies;
- Minimizing thermal loadings on transmission and distribution facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
- Analyzing the dynamic stability of the transmission system under various contingency conditions;
- Ensuring the available system fault current imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
- Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
- Coordinating transmission planning activities in broader regional evaluations with the MISO, ReliabilityFirst ("RF") and neighboring transmission owners;
- Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
- Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
- Analyzing the performance of the distribution system to ensure reliability, adequacy to meet future load growth, DER penetration, and to address age/condition of existing facilities; and
- Ensuring compliance with FERC, NERC and RF Reliability Standards.

3.8.1. Transmission Planning Process

At a high level, CEI South's transmission performance planning models include existing facilities at or above 69 kV, critical system conditions, and study years. Modeled Facilities represent, at a minimum, required upgrades and could include future facilities not yet in service. The models may include distribution circuits and substations. The models aid in analyzing More Probable, Less Probable and Extreme Contingency events. The studied time periods may be for near-term (1 to 5 years) or long-term (6 to 10 years) and for peak and off-peak demand periods; however, the planning horizon may be increased to include transmission or generation plans. Using these models, CEI South may study system growth, generator interconnections, transmission interconnections, Load Serving Entity ("LSE") interconnections, and other studies as needed. Additional planning process details are provided in CEI South's VEC-008, Electric Transmission Planning Criteria (*Technical Appendix Attachments 3.9 VEC-008 Electric Transmission Planning Criteria*).

3.8.2. Existing Transmission System

CEI South's transmission system is comprised of 64 miles of 345 kV lines, 430 miles of 138 kV lines, and 563 miles of 69 kV lines.

The existing Transmission system has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (345kV-138 kV) and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station and Duff Substation, a 345kV interconnection to Big Rivers' Coleman Substation, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at AES/IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at CEI South's Newtonville Substation.

3.8.3. Import and Export Capability Assessment

As mentioned above, CEI South's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 660 MW in peak demand periods and approximately 750 MW in off-peak demand periods (or approximately 35-40% of peak demand). The current import capabilities were used as a maximum threshold for the energy purchases and sales during the Risk Analysis.

Although CEI South has the capability to offset internal generation with imported capacity, this is not a long-term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)
- Anticipated congestion costs
- Real-time binding constraints

Transmission planning's most recent analysis in its internal long-range planning study looked at a sensitivity on import capability around MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 and concluded that the maximum import capability in 2031/2032 would increase to 1,280 MW in the peak demand periods.

3.8.4. Transmission Facilities as a Resource

As part of this year's IRP, CEI South retained 1898 & Co to perform transmission planning analyses evaluating 14 potential resource futures (or "Transmission Study Scenarios"). The resulting study report is included in the *Technical Appendix Attachment 2.3, Transmission Study (Confidential)*.

<u>*Study Overview:*</u>

The Transmission Study Scenarios included analyzing:

- the retirement of additional coal generation and partial replacement of these retirements with Battery Energy Storage System ("BESS"),
- the addition of a synchronous condenser,
- the addition of an aeroderivative, and
- import from the MISO market.

Each of these cases also included the addition of various levels of renewable resources.

The study (Steady-State analysis only) was performed for the Summer peak, Shoulder (off-peak), and Winter peak demand periods. The five-year and ten-year models utilized were from the latest 2024 MISO Transmission Expansion Plan ("MTEP") model series, which includes future transmission system projects and approved generation interconnections. The ten-year models and transmission scenarios were inclusive of MISO's LRTP Tranche 2.1 portfolio for the region. Additionally, given uncertainty of LRTP project #35 meeting the 2032 in-service date prescribed by MISO, a ten-year sensitivity study removing this project from the models was performed. Modeling parameters for the new renewable resource additions were utilized from the latest cycle of the MISO generation interconnection process. These generation projects included known generation replacement projects and those in final negotiations to execute generation interconnection agreements with MISO. Incorporating these projects ensured the use of the most up-to-date modeling data for generation resources within CEI South's service area. The analysis incorporated renewable resources already in the MISO queue and modeled within MISO systems, along with the new combustion turbines at the A.B. Brown power plant and the Posey Solar project.

Study Results:

Evaluation of the Transmission Study Scenarios found several issues primarily tied to less generation on the system and a shift of additional issues arising in the Shoulder over the Summer period. Under heavy import conditions, severe voltage reinforcements are required in the Shoulder period. The highest magnitude of reinforcement costs is shown in the Winter period under heavy import conditions. Network upgrades needed to mitigate violations observed across all demand periods ranged from $0 million to $242.6 million depending on the transmission scenario.

Under Shoulder and Summer demand periods in the five-year planning horizon, the Culley G2 BESS or aeroderivative conversions evaluated (Transmission Study Scenarios 6 and 9) required no system reinforcements. Under the same demand periods and planning horizon for Culley G3 BESS conversion (Transmission Study Scenario 7), an additional $22.6 million in thermal and voltage reinforcements were required. When evaluating both Culley G2 and G3 BESS conversion (Transmission Study Scenario 8), additional thermal and voltage violations are produced which increases system reinforcements to $39.9 million. Considering the Culley G2 or G3 BESS conversions under heavy import (Transmission Study Scenarios 11 and 12), the system reinforcements ($56.6 million) required for Culley G2 BESS conversion were less severe than under Culley G3 BESS conversion ($156.8 million). In summary, Culley G2 BESS conversion causes less thermal and voltage impacts than Culley G3 BESS conversion.

The magnitude of system reinforcements was the most significant during the five (5) year Winter demand period, driven by heavy import condition. Heavy import conditions represent transmission scenarios when CEI South's dispatchable resources (F.B. Culley 2 and 3, and A.B. Brown CTs) are offline or unavailable. The reinforcements were estimated between $22.1 million and $242.6 million. Major upgrades on the high-end included rebuilding several transmission lines on the 69 kV and 138 kV system, two (2) additional 345/138 kV transformers at A.B. Brown, a 62.4 MVAr capacitor bank at Culley 69kV sub, and an additional 249.6 MVAr of reactive support spread across CEI South's footprint. The need for additional VAR support across the system is correlated to dispatchable generation being unavailable. A new 40-mile Ameren Norris City (IL) 345kV to A.B. Brown 345 kV line was considered as a potential reinforcement and the preliminary estimate for this potential project is $136 million, accounting for over half of the $242.6 million mentioned above.

Converting Culley Unit 2 to a Synchronous Condenser was reviewed as an option for VAR support and was determined to be unfeasible due to the design of this particular unit.

IRP Impact:
For capacity expansion modeling, CEI South accounted for uncertainty and price volatility by incorporating conservative estimates for transmission upgrades caused by each potential technology added to the F.B. Culley 2 site. In the case that there are no additional units brought online (Transmission Study Scenario 3), the total upgrade cost was $47.9 million. This value was used to represent the cost of transmission system upgrades if a storage resource was assumed to be placed in service (Transmission Study Scenario 2), as well as in the case that the F.B. Culley 2 site interconnection rights were allowed to expire. Because Scenario 2 represents only the shoulder months, the summer transmission cost from Transmission Study Scenario 3 was used as a conservative estimate of the maximum potential upgrade cost. For the addition of a reciprocating engine or aeroderivative engine at the F.B. Culley 2 site, the highest seasonal costs associated with the Culley G2 aeroderivative (Transmission Study Scenario 4) were estimated at $22.8 million.

3.8.5. Distribution Planning Process

In 2025, Transmission Planning and Distribution Planning teams both completed separate but coordinated Long Range Planning reports which assessed future impacts to each system. Both analyses are coordinated to review load growth, generation changes, and overall system limitations and capabilities.

Furthermore, the Distribution Long Range Planning Report discusses further details on CEI South distribution planning criteria used in system analysis. The public version of the Distribution Long Range Planning Report is included in the *Technical Appendix Attachment 3.8*. Additional planning process details are provided in CEI South's VEC-008, Electric Transmission Planning Criteria, see *Technical Appendix Attachment 3.9.*

3.8.6. Evolving Technologies and System Capabilities

Transmission Capacity Investments:
MISO's 2024 Transmission Expansion Plan identified numerous Multi-Value Projects aimed at increasing regional transmission capacity throughout the central portion of MISO's footprint. MISO's Board of Directors approved these transmission investments in

December of 2024. MISO's approved plan includes transmission capacity additions in CEI South's footprint.

FERC Order 881 - Ambient Adjusted Line Ratings:
CEI South is actively engaged in implementing ambient-adjusted transmission facility ratings (AARs). FERC Order 881 was issued in December 2021 and directed Regional Transmission Operators (such as MISO) and Transmission Owners (such as CEI South) to implement AARs. CEI South actions taken to date include:

- Working collectively with MISO and other Transmission Owners on AAR implementation;
- Conducting monthly internal stakeholder meetings to review implementation status;
- Implementation of an advanced facility ratings database (software that enables the use of ambient adjusted ratings); and
- Completing Energy Management System upgrades required to manage ambient adjusted ratings in real-time operations and communicate those values to MISO.

Historically, transmission facility ratings have been static and only adjusted seasonally. AARs provide additional real-time capacity on transmission facilities when outdoor temperatures are lower. Implementing AARs may reduce or alleviate transmission facility congestion by allowing system operators to apply the increase in the facility's rating, when applicable.

FERC Order 2222 - Distributed Energy Resources:
FERC Order 2222 requires Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") to allow aggregated distributed energy resources ("DERs") to participate in wholesale electricity markets. In an effort to prepare for MISO's implementation of order 2222, CEI South has created an internal task force to ensure compliance with FERC's mandate and MISO's tariff. The task force will coordinate with MISO, IURC, and other authorities to align internal DER processes, registration, system readiness, tariffs, and compliance with reliability and cybersecurity standards.

3.9. Other Modeling Assumptions

3.9.1. Resource Availability

A key model input is the availability of new generation resources, which signals how quickly resources can be brought online. For all scenarios except for those with large load additions (large load sensitivity analysis and the alternate reference case), resource availability assumptions remained constant over the modeling period. As shown in Figure 3-40, renewable build constraints were intentionally aggressive as requested by stakeholders.

Resource availability was also informed by the 2024 All-Source RFP, which indicated that solar and storage were more readily accessible than wind facilities in or near Indiana. Finally, it is important to note that 2035 was identified as the earliest reasonable in-service date for advanced nuclear technology, as informed by the technology assessment.

Figure 3-40 – Resource Availability for Core Scenarios[31]

Technology	1st Year Available	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal			
F Class CT	2030	1 Project, 246 MW	1 Project, 246 MW
J Class CT	2030	2 Projects, 874 MW	2 Project, 874 MW
Reciprocating Engine	2030	2 Projects, 220 MW	4 Projects, 440 MW
Aeroderivative	2030	2 Projects, 114 MW	4 Projects, 228 MW
1x1 F Class CC	2032	1 Project, 454 MW	1 Project, 454 MW
1x1 J Class CC	2032	1 Project, 624 MW	1 Project, 624 MW
Renewables			
Solar	2028	4 Projects, 400 MW	18 Projects, 1,800 MW
Solar + Storage	2028	3 Projects, 300 + 150 MW	10 Projects, 500 + 250 MW
Wind	2030	4 Projects, 800 MW	10 Projects, 2,000 MW
Wind + Storage	2030	3 Projects, 600 + 300 MW	5 Projects, 1,000 + 500 MW
Hydro	2032	2 Projects, 58 MW	2 Projects, 58 MW
Storage			
4-hour 50 MW Storage	2028	5 Projects, 250 MW	10 Projects, 500 MW
4-hour 100 MW Storage	2028	5 Projects, 500 MW	10 Projects, 500 MW
8-hour 100 MW Storage	2028	3 Projects, 300 MW	5 Projects, 500 MW
Nuclear			
Nuclear	2035	1 Project, 100 MW	1 Project, 100 MW

For the simulations that included a large load addition, such as the alternate reference case and the large load sensitivity runs, resource build constraints were expanded. As shown in Figure 3-41**,** the constraints for most technologies were expanded to at least twice their base levels. After running the simulations, it was confirmed that these cumulative limits were not binding for either the core scenarios or in the large load addition cases as the model did not select the maximum number of any units.

[31] During a sensitivity analysis, long-duration iron-air storage was not selected in any scenario portfolio. When the resource was included in the capacity expansion model, it consistently produced higher-cost outcomes. Based on these results, it was not carried forward in subsequent capacity expansion modeling.

Figure 3-41 – Resource Availability for Large Load Addition Cases[32]

Technology	1st Year Available	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal			
F Class CT	2030	3 Projects, 737 MW	6 Projects, 1,475 MW
J Class CT	2030	3 Projects, 1,311 MW	6 Projects, 2,623 MW
Reciprocating Engine	2030	4 Projects, 439 MW	8 Projects, 878 MW
Aeroderivative	2030	4 Projects, 228 MW	8 Projects, 457 MW
1x1 F Class CC	2032	2 Projects, 908 MW	2 Projects, 908 MW
2x1 G/H Class CC	2032	4 Projects, 3,825 MW	4 Projects, 3,825 MW
1x1 J Class CC	2032	2 Projects, 1,248 MW	2 Projects, 1,248 MW
2x1 J Class CC	2032	4 Projects, 5,477 MW	4 Projects, 5,477 MW
Renewables			
Solar	2028	10 Projects, 1,000 MW	20 Projects, 2,000 MW
Solar + Storage	2028	6 Projects, 600 + 300 MW	20 Projects, 2,000 + 1,000 MW
Wind	2030	8 Projects, 1,600 MW	20 Projects, 4,000 MW
Wind + Storage	2030	6 Projects, 1,200 + 600 MW	10 Projects, 2,000 + 1,000 MW
Hydro	2032	4 Projects, 116 MW	4 Projects, 116 MW
Storage			
4-hour 50 MW Storage	2028	10 Projects, 500 MW	20 Projects, 1,000 MW
4-hour 100 MW Storage	2028	10 Projects, 1,000 MW	20 Projects, 2,000 MW
8-hour 100 MW Storage	2028	6 Projects, 600 MW	10 Projects, 1,000 MW
Nuclear			
Nuclear	2035	2 Projects, 200 MW	2 Projects, 200 MW

3.9.2. MISO Direct Loss of Load Modeling

Beginning with the 2028/2029 Planning Year, MISO is transitioning its capacity accreditation methodology from the SAC construct to the DLOL framework. The DLOL approach represents a significant evolution in how MISO measures resource adequacy, shifting from fixed, technology-specific capacity factors to a probabilistic model based on each resource's performance during periods of highest reliability risk. Under this construct, accreditation is determined by a resource's contribution to avoiding loss-of-load events rather than its average seasonal availability.

[32] During a sensitivity analysis, long-duration iron-air storage was not selected in any scenario portfolio. When the resource was included in the capacity expansion model, it consistently produced higher-cost outcomes. Based on these results, it was not carried forward in subsequent capacity expansion modeling.

3.9.2.1. Data Sources and Modeling Approach

CEI South incorporated MISO's updated DLOL methodology into its 2025 IRP modeling to ensure consistency with the evolving regional framework. The most current publicly available MISO sources were used to obtain capacity accreditation values for each technology type. SAC accreditation percentages for wind and solar were taken from MISO's 2025/2026 Planning Year ("PY") Loss of Load Expectation ("LOLE") Report[33], while accreditation for all other technologies was sourced from MISO's 2023/2024 PY Effective Load Carrying Capability ("ELCC") data[34]. SAC values were applied through Summer 2027, after which DLOL implementation is expected to begin in Summer 2028. MISO's 2025/2026 PY Indicative DLOL Results[35] were used from 2028 through 2030. DLOL values for 2030, 2033, and 2043 were obtained from MISO's Regional Resource Assessment ("RRA") Technical Appendix[36], with interpolation used to determine values for intermediate years, and post-2043 values held constant through 2045.

3.9.2.2. Transition from SAC to DLOL

To ensure a consistent and realistic transition from SAC to DLOL accreditation, CEI South applied a smoothing process to the DLOL values across all resource types. Initial DLOL results from MISO indicated steep accreditation declines during the early implementation years. Following stakeholder feedback regarding this shift, CEI South introduced a moderated adjustment between 2028 and 2035. Figure 3-42 shows the change to the solar capacity accreditation. This smoothing approach preserves the overall downward trend observed in MISO's published data while providing a more stable near-term trajectory for planning and cost modeling purposes.

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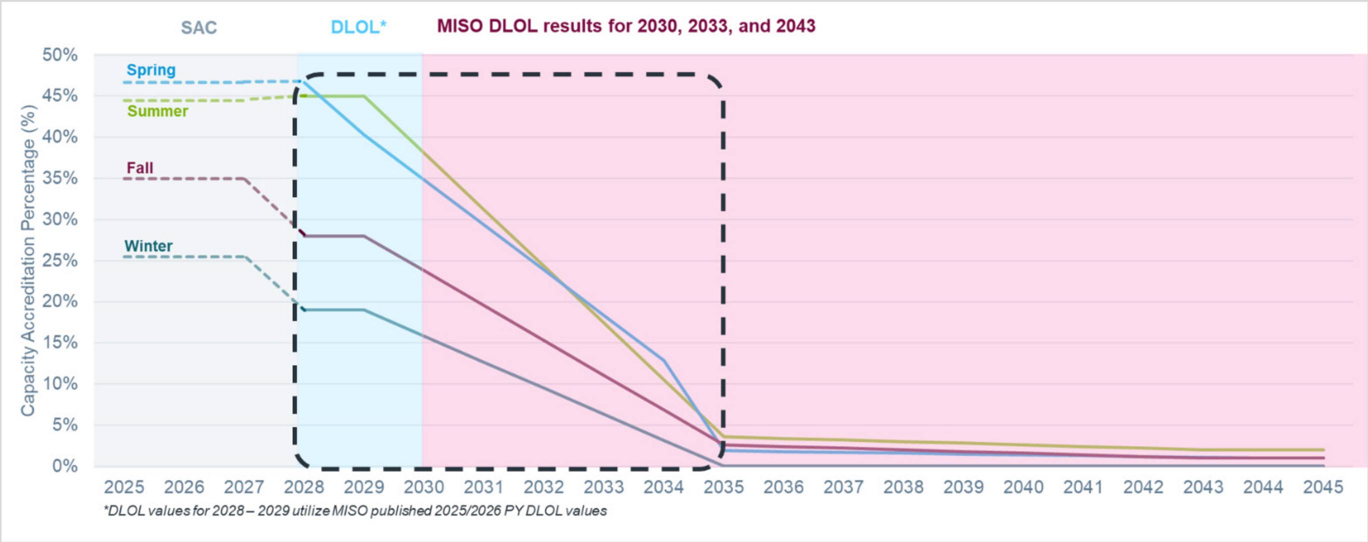
[33] Planning Year 2025 – 2026 Loss of Load Expectation Study Report. MISO. https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401. March 2025. Page 21.

[34] Market Redefinition: Accreditation Reform. MISO. https://cdn.misoenergy.org/20240228%20RASC%20Item%2005a%20Accreditation%20Presentation%20RASC-2020-4%202019-2631885.pdf. February 28, 2024. Page 33.

[35] Planning Year 2025 – 2026 Indicative Direct Loss of Load (DLOL) Results. MISO. https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf. April 2025. Page 3.

[36] Technical Appendix: 2024 Regional Resource Assessment Assumptions and Methodology. MISO. https://cdn.misoenergy.org/2024%20RRA_Technical%20Appendix676208.pdf. November 2024. Page 11. Accreditation values between 2028 and 2035 were adjusted for the smoothing process; the 2030 values were not utilized, and the 2033 values were incorporated in 2035.

Figure 3-42 – Example of Smoothed Transition from SAC to DLOL for Solar Resources



Portfolio Development and Evaluation

Chapter 4

4.1. Portfolio Development

CEI South developed a wide range of portfolios for scenario modeling in the dispatch module of EnCompass and ultimately for the probabilistic modeling portion of this IRP process. In collaboration with external stakeholders and informed by feedback provided in the IURC Director's Report on the 2022/2023 IRP, CEI South developed 12 portfolios for final evaluation. These included a status quo case, where F.B. Culley 3 continues to run on coal throughout the study period for benchmarking purposes, scenario-based portfolios optimized under varying market conditions, portfolios focused on existing resource decisions, diversified portfolios with a balanced mix of generation technologies, and renewables-focused portfolios incorporating stakeholder input. Each portfolio was designed with the flexibility to include near-term solar, wind, and battery storage resources identified through the All-Source RFP. Mid- and long-term resource options were drawn from both the 2024 All Source RFP and a comprehensive technology assessment performed by 1898 & Co., which provided cost and performance data for technologies not represented in the 2024 All Source RFP. Values trended forward using available NREL cost curves. All portfolios were designed to include energy efficiency and demand response programs. DSM programs were selected for cost-effectiveness during the first stage of deterministic runs; runs that were selected 95% of the time were then included in all portfolios. All near-term programs included in the previously approved 2025-2027 plan were included in the model.

4.1.1. Optimization Runs

4.1.1.1. Deterministic Portfolio Results

Deterministic modeling was conducted to evaluate individual conversion options at existing CEI South generation sites. In each case, the model was directed to include a specific conversion configuration and optimize a portfolio surrounding that decision. This approach allowed CEI South to compare the cost, performance, and operational outcomes of each option under Reference Case conditions, establishing baseline expectations for cost, capacity, and operational performance across all conversion and retirement pathways.

Several consistent trends emerged from these model runs. In more than half of the simulations, the model selected the conversion of the existing A.B. Brown 5 and 6 combustion turbines to a 2x1 Combined Cycle, indicating the capacity and energy need, as well as the high firm capacity value associated with the thermal units. At the F.B. Culley 3 site, the model generally favored retirement of the unit, although this outcome is heavily influenced by the path selected at the A.B. Brown site.

4.1.1.1.1. F.B. Culley 2 Replacement

In anticipation of the suspension of F.B. Culley 2 at the end of 2025, CEI South evaluated four potential replacement options for this unit: installing natural gas aeroderivative or reciprocating engines, building a lithium-ion storage facility, or allowing the interconnection rights to expire. Each option was modeled individually under Reference Case assumptions to assess relative cost and system performance. The results of these model optimization runs are summarized below in Figure 4-1.

The deterministic analysis showed that allowing the interconnection rights to expire resulted in the lowest-cost outcome, within approximately one percent of the cost of constructing a lithium-ion storage facility. Due to the similar portfolio cost of each pathway, the decision for future pathways at F.B. Culley 2 remained unconstrained in subsequent model runs and portfolio development, with the exception of portfolio 12, the delayed reference case.

Figure 4-1 – F.B. Culley 2 Deterministic Model Results

Year	F.B. Culley 2 Aeroderivative	F.B. Culley 2 No Interconnect Re-Use	F.B. Culley 2 Reciprocating Engines	F.B. Culley 2 Storage
2028	+1 FBC2 Aero (86 MW)	1 FBC2 Do Nothing	+1FBC2 Recip Engines (110 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031				
2032	-1 FB Culley:3 Retire 2032 (-270 MW) +1 50 MW 4 Hour Storage (50 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2033		+1 100 MW 4 Hour Storage (100 MW)		+1 50 MW 4 Hour Storage (50 MW)
2034				
2035				
2038				
2039				
2040				
2041	+1 Non IRA Solar PV (100 MW)		+1 50 MW 4 Hour Storage (50 MW)	
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)		
2043				+1 50 MW 4 Hour Storage (50 MW)
2044				
2045	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	
% Delta to Min NPV	**8.1%**	**0.0%**	**5.3%**	**1.0%**

4.1.1.1.2. Demand Side Management Deterministic Runs

Deterministic model runs conducted for conversion decisions at existing sites, together with the reference case and scenario-based runs, were used to evaluate the selection frequency of Energy Efficiency and Demand Response programs. In total, 15 runs were analyzed to identify which DSM programs were most consistently selected by the model. The Near-term ("NT") programs shown in Figure 4-2, which cover the years 2025 through 2027, were part of the previously approved plan and were included as fixed programs in this analysis. In addition, other programs, such as the Demand Response Aggregator program ("DR

Industrial") approved in Cause No. 45990, were also fixed programs consistent with the approved plan.

Figure 4-2 summarizes how frequently each program was selected across the DSM Deterministic runs. Programs that were selected more than 95% of the time were deemed consistently cost-effective and subsequently treated as a fixed resource in all future portfolio optimizations. The remaining programs were allowed to be selected, but not fixed, in each portfolio.

Figure 4-2 – Demand Side Management Deterministic Results

Program Name	Fixed or Selectable	Selection Frequency	Selection Percent
DR Industrial (DR Aggregation Program)	**Fixed**	**19/19**	**100%**
DR_CI Battery	Selectable	0/19	0%
DR_CI BYOT	**Selectable**	**19/19**	**100%**
DR_CI EV	Selectable	0/19	0%
DR_CI TOU CPP	Selectable	18/19	94%
DR_CI WH Grid	Selectable	9/19	47%
DR_Res AC Switch	**Fixed**	**19/19**	**100%**
DR_Res AC Switch_NT	**Fixed**	**19/19**	**100%**
DR_Res Battery	Selectable	1/19	5%
DR_Res BYOT	Selectable	4/19	21%
DR_Res BYOT_NT	**Fixed**	**19/19**	**100%**
DR_Res EV	Selectable	1/19	5%
DR_Res Smart Cycle	Selectable	1/19	5%
DR_Res Smart Cycle_NT	**Fixed**	**19/19**	**100%**
DR_Res TOU CPP	**Selectable**	**19/19**	**100%**
DR_Res WH Grid	Selectable	1/19	5%
DR_Res WH Switch	**Fixed**	**19/19**	**100%**
DR_Res WH Switch_NT	**Fixed**	**19/19**	**100%**
EE_CI_ERAP_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_IQ HEAR_NT, V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_IQW_V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_Res_HER_V1, V2, V3	Selectable	0/19	0%
EE_Res_Tier 1_HER_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_Res_Tier1_V1, V2, V3	Selectable	0/19	0%
EE_Res_Tier2_V1, V2, V3	Selectable	2/19 - 3/19	11-16%

A supplemental sensitivity analysis was also conducted to assess the impact of a shorter program horizon for Demand Response programs. This case evaluated only the first six years of cost and production, relative to the 18-year study period used in the deterministic runs. No additional DR programs were selected when evaluated based on the first 6 years.

4.1.1.1.3. Distributed Generation Resource Portfolios

CEI South also evaluated a potential distributed generation solar incentive program intended to encourage customers to install behind-the-meter solar resources, thereby reducing system energy requirements. CEI South worked with Itron to update its solar payback model to include a $500 per kW incentive, to increase the adoption rate of behind-the-meter solar. Based on a solar PV adoption forecast developed by Itron, the program was estimated to reduce system load by a cumulative 137 MW (non-coincident) by 2045 and increase the net present value of portfolio revenue requirements by approximately $34.6 million.

When the IRP EnCompass model performed an optimized capacity expansion simulation under Reference Case conditions with this reduced load, the resulting portfolio was nearly identical to the Reference Case. The only difference was a one-year delay in the addition of storage resources, from 2039 to 2040 and from 2042 to 2043. This result indicates that while the incentive program would reduce energy requirements, long-term planning needs remain primarily driven by capacity. Furthermore, cost savings from reduced operational costs to serve the reduced load were insufficient to offset the cost of the incentive program, as the all-in cost of the optimized distributed generation portfolio was approximately $10 million higher than the Reference Case portfolio. Therefore, a distributed generation portfolio was excluded from the risk analysis.

4.1.1.2. Scenario-Based Portfolios

Scenario-Based portfolios (Reference Case, Low Regulatory, High Regulatory, Alternate High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions, and levels of electricity demand. The scenario-based portfolios move from Low to High Regulatory, with increasing levels of regulation and higher or lower economic drivers. While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to produce and test portfolios in plausible future states that differ from the reference case.

Following stakeholder feedback, the exact model outputs from these scenario optimization runs were used to produce scenario-driven portfolios. Note that these portfolios are developed under varying load conditions (as per the scenario definitions) but are then simulated using the same load inputs as all other portfolios during the risk analysis. These scenario-based portfolios are shown in Figure 4-3.

Figure 4-3 – Scenario Optimization Model Outputs

Year	Optimized Reference Case *(Portfolio 1)*	Optimized Low Reg *(Portfolio 8)*	Optimized High Reg *(Portfolio 9)*	Optimized Alt High Reg *(Portfolio 10)*
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)			
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)		
2040	+1 50 MW 4 Hour Storage (50 MW)			
2042		+1 50 MW 4 Hour Storage (50 MW)		
2043	+1 50 MW 4 Hour Storage (50 MW)			
2045		+1 Non IRA Solar PV + Storage (100 + 50 MW)		

4.1.2. Final Portfolios for Risk Analysis

With these early modeling results in mind, additional portfolios and iterations were developed based on 1) stakeholder feedback, 2) lessons learned from preliminary portfolio optimization results, and 3) examining tradeoffs in different existing resource decision timing. Once all twelve of these diverse portfolios were created, they were run through the EnCompass model to be considered in the Risk Analysis portion of this IRP.

Figure 4-4 summarizes the resource buildouts for the portfolios selected for inclusion in the risk analysis[37].

[37] Portfolio 12 (Delayed Reference Case) was updated from the fourth stakeholder meeting held on 10/23/2025. In that meeting, the 50 MW 4-hour storage resource was presented to come online in 2042; the table entry was corrected to 2040. The slide deck on the CenterPoint IRP website (Integrated Resource Plan (IRP)) reflects this update.

Figure 4-4 – Final Risk Analysis Portfolios

Year	Portfolio1_Reference Case Portfolio	Portfolio2_Convert FBC3 to NG by 2035	Portfolio3_FBC3 on Coal without ABB7	Portfolio4_FBC3 on Coal to SMR	Portfolio5_FBC3 to Simple Cycle Gas Turbine	Portfolio6_Renewable Heavy Portfolio
2028	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	1 ABB5/6 Continue
2032	-1 FB Culley:3 Retire 2032 (-270 MW)		+1 100 MW 4 Hour Storage (100 MW)			-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)		+2 100 MW 4 Hour Storage (200 MW)		+1 100 MW 4 Hour Storage (100 MW)	+2 100 MW 4 Hour Storage (200 MW)
2034						
2035		+1 FB Culley:3 NG 2035 (270 MW)		-1 FB Culley:3 Retire 2035 (-270 MW) +1 Nuclear - SMR (100 MW)	-1 FB Culley:3 Retire 2035 (-270 MW) +1 J Class SCGT (385 MW)	
2038						
2039						
2040	+1 50 MW 4 Hour Storage (50 MW)					
2041					+1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind (200 MW)
2042			+1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW)		+1 Non IRA Wind + Storage (200 + 100 MW)
2043	+1 50 MW 4 Hour Storage (50 MW)					
2044						
2045			+1 FB Culley:3 thru 2045 (270 MW) +2 Non IRA Solar PV (200 MW) +1 Non IRA Wind (200 MW)		+1 Non IRA Wind (200 MW)	

Year	Portfolio7_FBC3 Gas Conversion with Renewables	Portfolio8_Low Reg Approach	Portfolio9_High Reg Approach	Portfolio10_Alt High Reg Approach	Portfolio11_FBC3 Co-Fire 2030	Portfolio12_Delayed Reference Case
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)
2030	+1 FB Culley:3 NG 2030 (270 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)	+1 FB Culley:3 Co-Fire 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	
2032		-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)		
2033	+2 100 MW 4 Hour Storage (200 MW) +1 50 MW 4 Hour Storage (50 MW)					
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)		+1 AB Brown7: Fired CCGT 2034 (850 MW)
2035						-1 FB Culley:3 Retire 2035 (-270 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)			-1 FB Culley:3 Retire (270 MW)	
2039					+2 50 MW 4 Hour Storage (100 MW)	
2040	+1 Non IRA Wind (200 MW)				+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)
2041						
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)				
2043						
2044					+1 50 MW 4 Hour Storage (50 MW)	
2045	+1 100 MW 4 Hour Storage (100 MW) +2 Non IRA Wind (400 MW)	+1 Non IRA Solar PV + Storage (100 + 50 MW)				+1 50 MW 4 Hour Storage (50 MW)

Moreover, Figure 4-5 explicitly states the motivation behind the development of these twelve portfolios. The first group includes the portfolios informed by the deterministic optimization results and explores various existing unit decisions. The second group, as mentioned in Section 4.1.1.2, is the scenario-based portfolios. The final group reflects portfolios shaped by stakeholder input. These portfolios include the two portfolios with an increased renewable penetration in CEI South's resources mix as well as a portfolio with a Small Modular Reactor as a potential resource option.

Figure 4-5 – Description of Portfolio Motivations

Portfolio Name	Motivation
2-Convert FB Culley 3 to NG by 2035	Deterministic Portfolios (economically optimized model given fixed existing site decisions and potential replacement options for F.B. Culley 3)
3-Continue FB Culley 3 on Coal through 2045	
5-FB Culley 3 to Simple Cycle Gas Turbine	
11-FB Culley 3 Co-Fire	
12-Delayed Reference Case	
1-Reference Case Portfolio	Scenario-Based Portfolios (economically optimized model for each scenario)
8-Low Regulatory Approach	
9-High Regulatory Approach	
10-Alternate High Regulatory Approach	
4-FB Culley 3 to Small Modular Reactor	Stakeholder Input Portfolios
6-Renewable Heavy	
7-FB Culley 3 Gas Conversion with Renewables	

4.2. Evaluation Of Portfolio Performance

Each of the risk analysis candidate portfolios were subjected to two different forms of risk modeling. One was scenario-based (deterministic), and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard. The inputs into the EnCompass model that were used to generate the following results are given in the *Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)*.

4.2.1. Scenario Risk Analysis (Simulated Dispatch in Each Scenario)

The IRP requires scenario-based modeling be performed as a part of the risk analysis. In the scenario-based risk analysis, the twelve candidate portfolios selected for further analysis were modeled under each of the four core scenarios with their respective market inputs. The following provides a summary of the results of this scenario-based risk analysis. The results shown in Figure 4-6 and Figure 4-7 are NPVRR and the cumulative carbon-dioxide emissions of each portfolio under each scenario. In the alternative high regulatory and high regulatory scenarios, capacity factor limitations associated with the CAA 111(b) and (d) legislation tend to increase the operating costs of portfolios while also limiting the portfolio emissions. The Preferred Portfolio performs fairly consistently across all four scenarios, avoiding extreme outcomes while allowing time for re-evaluation in a future IRP before the F.B. Culley 3 decision must be finalized.

Figure 4-6 – Portfolio NPVRR (Million $)

Portfolio	Reference Case	Alt High Regulatory	High Regulatory	Low Regulatory
1-Reference Case	$3,455	$4,613	$4,093	$3,458
2-FBC3 NG 2035	$3,430	$4,338	$4,119	$3,338
3-FBC3 on Coal	$3,959	$4,639	$4,435	$4,211
4-FBC3 to SMR	$4,126	$5,164	$4,464	$4,433
5-FBC3 to SCGT	$4,145	$5,009	$4,620	$4,128
6-Renewable Heavy	$4,144	$5,417	$4,315	$4,536
7-FBC3 NG with Renewables	$4,174	$5,336	$4,604	$4,193
8-Low Reg	$3,497	$4,572	$4,047	$3,431
9-High Reg	$4,247	$4,185	$2,970	$4,721
10-Alt High Reg	$3,960	$4,057	$3,294	$4,389
11-FBC3 Co-Fire	$3,556	$4,557	$4,181	$3,485
12-Delayed Reference	$3,625	$4,572	$4,175	$3,572

Figure 4-7 – Portfolio Total CO_2 Emissions Over Study Period (Million Tons)

Portfolio	Reference Case	Alt High Regulatory	High Regulatory	Low Regulatory
1-Reference Case	61	46	39	63
2-FBC3 NG 2035	69	55	46	72
3-FBC3 on Coal	69	78	57	70
4-FBC3 to SMR	66	53	44	66
5-FBC3 to SCGT	51	61	46	58
6-Renewable Heavy	35	44	34	39
7-FBC3 NG with Renewables	42	49	36	50
8-Low Reg	61	46	39	63
9-High Reg	34	43	32	38
10-Alt High Reg	51	44	37	53
11-FBC3 Co-Fire	68	50	43	69
12-Delayed Reference	62	52	43	65

4.2.2. Probabilistic Risk Analysis (Simulated Dispatch 200 Runs Scorecard)

After selecting the twelve portfolios for further consideration and completion of the scenario-based risk assessment, the remaining steps are to conduct the 200 iteration stochastic risk assessment, complete the balanced scorecard, and consider "other" relevant factors to select the Preferred Portfolio.

A comprehensive risk analysis using 200 iterations provides a more thorough understanding of how the different portfolios perform under a range of scenarios. As with any analysis, the risk assessment and subsequent balanced scorecard do not provide CEI South with an answer but instead offer insights into tradeoffs associated with the portfolios across a range of possible future conditions. Among other things, the results of this evaluation help CEI South get a clearer picture of the balance between total portfolio cost, the cost uncertainty (measured by the 5^{th} and 95^{th} percentile of cost outcomes over the planning horizon), the carbon equivalent profile, the percentage dependence on energy and capacity purchases and sales, and the stability, reliability, and resilience of the portfolios based on the probabilistic range of potential outcomes.

A color-coded comparison (shaded automatically by the Microsoft Excel spreadsheet) of the balanced scorecard is shown below in Figure 4-8[38]. The color coding represents the relative ranking among the portfolios. Green generally indicates scoring well relative to other portfolios within the same metric, and red generally indicates scoring poorly relative to other portfolios within the same metric. The color scheme is purely for illustrative purposes to show where differences between the best-performing portfolio and the worst-performing portfolio for that metric. Since the color coding is purely relative to the other portfolios, red does not necessarily mean that a portfolio performed poorly on that metric, but relatively worse than other portfolios. For more information on this analysis, please see the final stakeholder presentation in *Technical Appendix Attachment 4.2 Stakeholder Materials*.

[38] The Capacity Purchases NPV ($M) shown in the scorecard and presented during the fourth stakeholder meeting held on 10/23/2025 have been updated and posted to the CenterPoint IRP website.

Figure 4-8 – IRP Portfolio Balanced Scorecard Color-Coded Comparison

Objective	Affordability					Environmental Sustainability				Reliability/Resiliency/Stability					Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	Incremental Energy Burden (%) 2030 - 2035	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (1000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Transmission Reliability Analysis MVAR	Transmission Reliability Analysis SCR	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
2-FBC3 NG 2035	$3,718	0%	$2,941	$4,464	0.13% - 0.22%	0.368	48,696	18,017	13,091	119	1,031	253	753	3.5	26%	9%	$217	$6
1-Reference Case	$3,726	0%	$2,963	$4,439	0.11% - 0.25%	0.346	44,302	12,877	10,650	61	842	340	665	3.5	26%	10%	$140	$14
8-Low Reg	$3,764	1%	$2,983	$4,475	0.15% - 0.20%	0.345	44,199	12,908	10,582	49	842	366	665	3.5	26%	10%	$167	$6
12-Delayed Reference	$3,836	3%	$3,195	$4,467	0.16% - 0.26%	0.391	46,535	21,885	14,539	56	701	444	665	3.5	23%	12%	$115	$18
11-FBC3 Co-Fire	$3,854	3%	$3,064	$4,587	0.18% - 0.17%	0.354	46,317	14,397	11,812	61	937	308	753	3.5	26%	10%	$192	$12
3-FBC3 on Coal	$4,034	8%	$3,511	$4,630	0.03% - 0.29%	0.522	53,636	51,793	25,931	43	302	835	626	3.5	15%	19%	$117	$22
10-Alt High Reg	$4,211	13%	$3,444	$4,829	0.17% - 0.48%	0.280	34,415	14,226	10,985	29	660	486	665	3.5	25%	9%	$159	$19
9-High Reg	$4,297	15%	$3,543	$4,926	0.43% - 0.44%	0.234	25,913	13,701	12,322	15	113	935	605	3.5	20%	14%	$128	$23
5-FBC3 to SCGT	$4,306	16%	$3,857	$4,770	0.14% - 0.59%	0.408	41,016	22,763	16,698	73	154	955	665	3.5	14%	21%	$93	$26
6-Renewable Heavy	$4,309	16%	$3,756	$4,723	0.10% - 0.62%	0.329	28,966	14,385	14,597	38	113	985	605	3.5	11%	30%	$95	$22
7-FBC3 NG with Renewables	$4,375	17%	$3,912	$4,771	0.26% - 0.49%	0.357	34,642	8,289	18,780	76	302	802	626	3.5	14%	23%	$106	$24
4-FBC3 to SMR	$4,456	20%	$3,674	$5,185	0.15% - 0.76%	0.342	45,224	18,653	11,950	52	938	273	665	3.5	26%	9%	$171	$13

1: Average net present value of portfolio revenue requirements from 2026 to 2045
2: Percent difference between average NPVRR of portfolio and reference
3-4: Fifth and ninety-fifth percentiles of net present value of NPVRR to show cost uncertainty
5: Increase in residential bill impact since 2026 as a percentage of median Vanderburg county resident forecasted annual income in 2030 and 2035
6: Quotient of average CO_2e from generation and average fleet generation from 2026 to 2045
7-9: Total CO_2 equivalent, SO_x, and NO_x emissions from 2026-2045
10: Total emergency unserved energy purchased from 2026 to 2045
11: Capacity from “spinning” thermal assets that can be ramped up or down (combined cycle, coal, nuclear)
12: Capacity from “fast start” assets that can be dispatched quickly (combustion turbine, battery)
13-14: Dynamic VAR support and short circuit ratio from transmission reliability analysis
15: Total energy sales as a percentage of total energy generation from 2026 to 2045
16: Total energy purchases as a percentage of total load from 2026 to 2045
17-18: Net present value of capacity sales and purchases from 2026 to 2045

4.3. Results By Portfolio

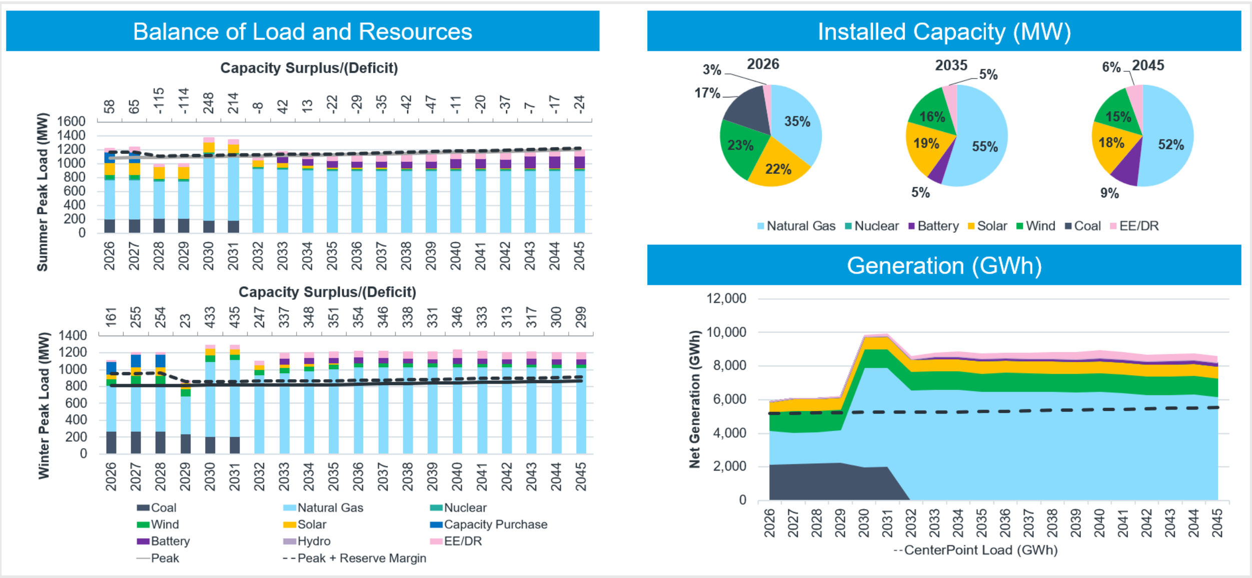
4.3.1. Reference Case Portfolio

The Reference Case portfolio represents the capacity expansion results from the Reference Case scenario. While this portfolio is the least cost in the capacity expansion (reference case) run, the portfolio becomes the second-lowest cost during the Risk Analysis (200 runs) portion of the analysis, as previously seen in Section 4.2.2. This portfolio allows for the expiration of interconnect rights at F.B. Culley 2 ("FBC2 Do Nothing"), conversion of the A.B. Brown 5 and 6 combustion turbines into a 2x1 Duct-Fired Combined Cycle ("A.B. Brown 7"), and retires CEI South's last remaining coal unit that it operates, F.B. Culley 3, at the end of 2031. In addition, the model builds a cumulative 200 MW of 4-hour battery energy storage resources beginning in 2033 through the end of the study period. The selection of batteries in the model is indicative of the need for long-term capacity on CEI South's system, especially following the implementation of MISO's DLOL methodology, which reduces the accreditation of intermittent resources.

The retirement of F.B. Culley 3 and the conversion of A.B. Brown 5 and 6 result in a highly efficient and relatively environmentally friendly portfolio, achieving among the lowest NO_x emissions compared to other portfolios. However, the early investment in A.B. Brown's conversion also necessitates a near-term rate increase, and the trend of increased demand for HRSGs and turbines creates a near-term price risk. The early A.B. Brown conversion and loss of the F.B. Culley 2 and F.B. Culley 3 interconnections also make the portfolio relatively inflexible, as it is less adaptable to changes in regulations, market conditions, and fuel costs.

The results dashboard for the reference case, shown in Figure 4-9, displays the Balance of Load and Resources on the left-hand side. This figure shows the need for capacity in the near-term, which makes the A.B. Brown conversion favorable, as it adds about 400 MW of firm capacity to the system. The installed capacity pie charts on the top right of the figure display the diverse mix of renewable, thermal, and demand-side resources included in the reference case. For all portfolio dashboards, the 32 MW of coal generation from Kyger Creek Generating Station, owned by the Ohio Valley Electric Corporation ("OVEC") and purchased by CenterPoint, is assumed to convert to natural gas in 2030. Finally, in the bottom left, it is observed that for the two years that A.B. Brown 7 and F.B. Culley 3 are online, CEI South's system produces significant excess energy, which it can sell to the MISO market and lower portfolio costs, ultimately benefiting CenterPoint customers but also introduces revenue risk if market conditions change.

Figure 4-9 - Reference Case Portfolio Results Dashboard

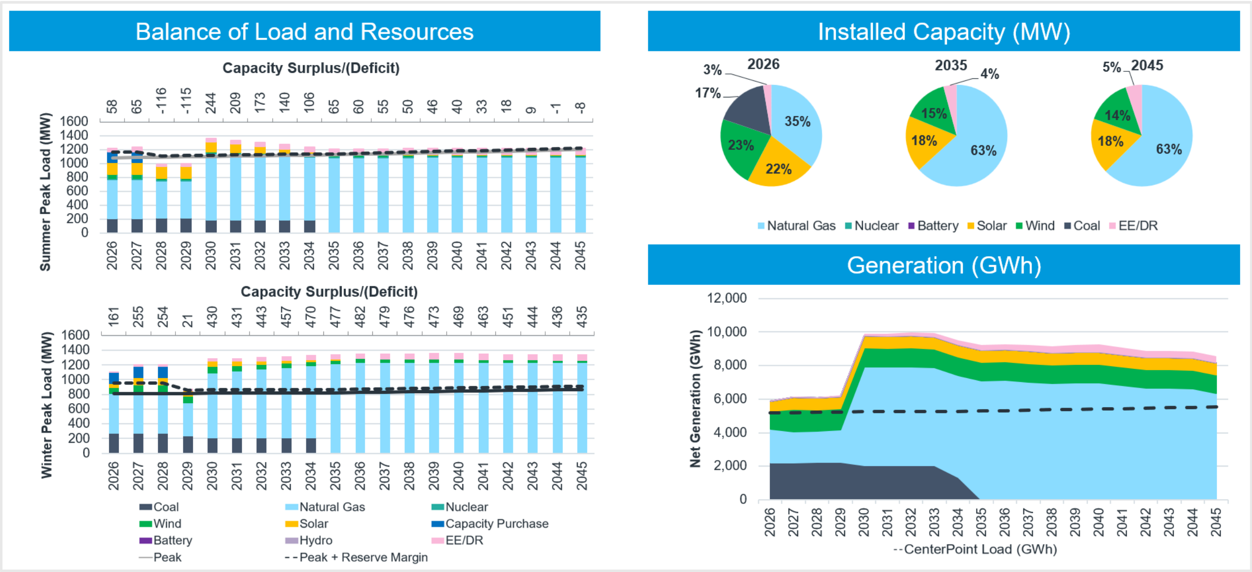


4.3.2. Convert F.B. Culley 3 to Natural Gas by 2035

This portfolio was designed to include the conversion of F.B. Culley 3 from a baseload coal-fired plant to a natural gas peaking plant beginning in 2035 and continuing through the end of the study period. This conversion preserves and repurposes much of the existing site infrastructure while maintaining valuable firm capacity on CEI South's system and lowering CO_2 emission rates. While the model was optimized around the conversion of F.B. Culley 3 to natural gas and the conversion of A.B. Brown 5 and 6 to A.B. Brown 7, no additional resources were necessary to meet all energy and capacity needs.

As seen in Figure 4-10, the inclusion of F.B. Culley 3 and A.B. Brown 7 results in CEI South being long on both capacity and energy, which can be sold to the MISO market to reduce the NPVRR and provide opportunities for economic development. While this portfolio has the lowest NPVRR across 200 draws of varying market conditions, it also relies on the highest levels of both energy and capacity sales, creating a revenue risk if market conditions differ. Moreover, the conversion of A.B. Brown in 2030 necessitates a potential near-term rate increase and introduces price risk from the increased demand for HRSGs and turbines, which could challenge the overall affordability of this portfolio. With natural gas resources comprising over 60% of total installed capacity, this portfolio is sensitive to changing regulations and volatility in fuel costs. Moreover, during the Risk Analysis, this portfolio showed the greatest amount of unserved energy along with the lowest amount of fast start resources, suggesting potential challenges for the reliability and resiliency of the system, absent potential mitigations.

Figure 4-10 – Convert F.B. Culley to Natural Gas by 2035 Results Dashboard

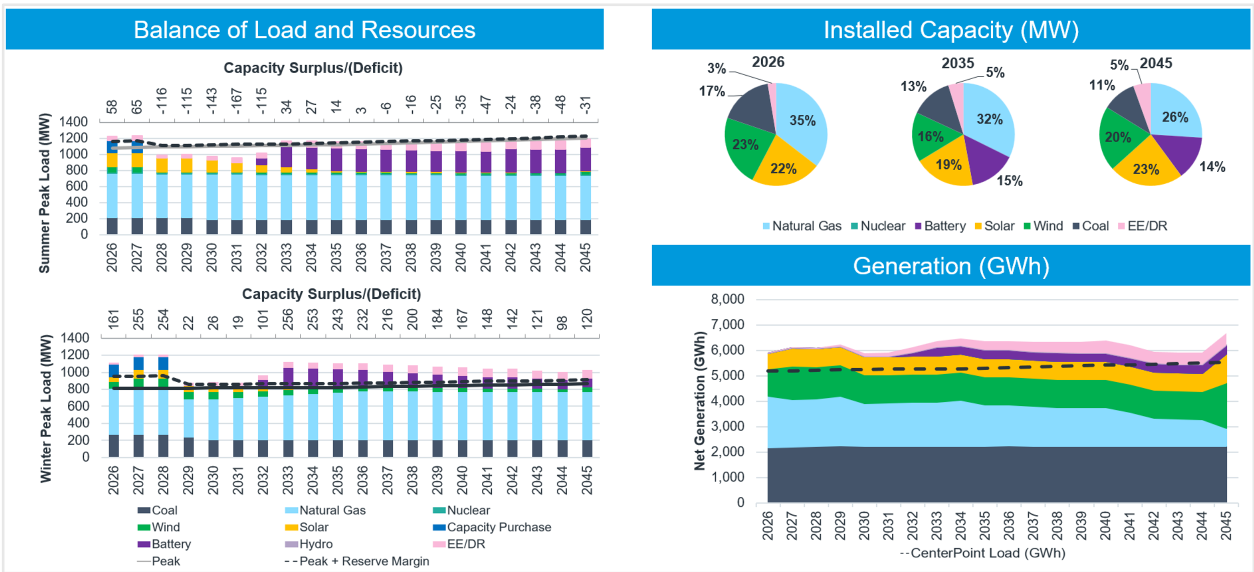


4.3.3. Continue F.B. Culley 3 on Coal through 2045

The F.B. Culley 3 on Coal portfolio serves as a Business As Usual ("BAU") case as it assumes no conversion of existing units and allows for the expiration of the interconnection rights at F.B. Culley 2. Without the conversion of the existing A.B. Brown units, the model chooses to build a cumulative 350 MW of storage facilities to maintain resource adequacy requirements. Moreover, in the final year of the planning horizon, additional solar and wind units are built to address energy needs. As shown in Figure 4-11 this portfolio relies on a significant amount of near-term capacity purchases until the additional storage resources are built.

The continuation of F.B. Culley 3 and the A.B. Brown CTs through the rest of the study period minimizes the need for near-term capital investment, which provides relative rate stability. To conform with environmental regulations included in the reference case, running F.B. Culley 3 on coal throughout the entire study period would require costly efficiency upgrades. Since this portfolio is unique in running F.B. Culley 3 on coal through 2045, the upgrades raise the base year (2026) revenue requirement, making the 2030 incremental energy burden appear lower than other portfolios in the near to midterm. Overall, this portfolio has a moderate NPVRR, approximately 8% greater than the least cost portfolio. As shown in the installed capacity graphs below, this portfolio is well diversified and therefore less susceptible to cost risk from fuel prices. However, the reliance on inefficient coal generation makes this portfolio environmentally unsustainable, with the highest emissions rates for all considered environmental scoring metrics. These high emissions present a regulatory risk if state and federal objectives change to focus on emissions reduction.

Figure 4-11 – F.B. Culley 3 on Coal through 2045 Results Dashboard

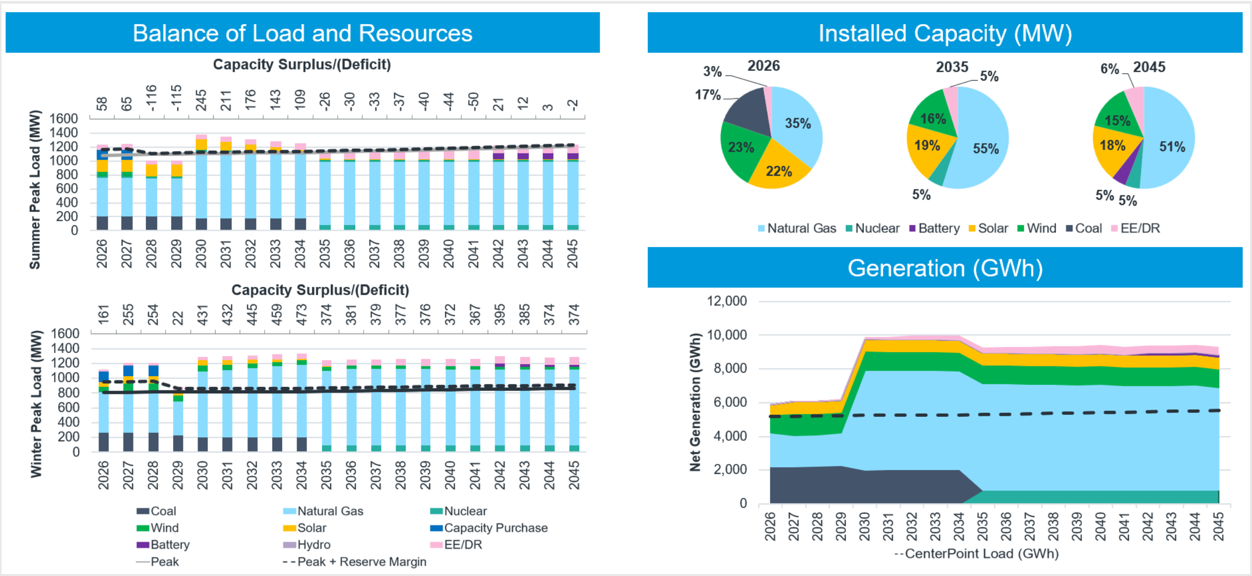


4.3.4. F.B. Culley 3 on Coal to Small Modular Reactor ("SMR")

Including an advanced nuclear portfolio allows CEI South to evaluate a long-term, zero-carbon firm resource that could support reliability as conventional coal resources continue to retire. Therefore, this portfolio retires F.B. Culley 3 at the end of 2034, while assuming that a small modular reactor ("SMR") would be brought online at the beginning of 2035. As shown in Figure 4-12, this portfolio is long on capacity from 2030 through 2034 as both F.B. Culley 3 and the A.B. Brown 7 are online.

This portfolio aligns with state and federal desire for nuclear energy, but the SMRs are also a new and unproven technology, which introduces significant long-term cost risk. The conversion of A.B. Brown 5 and 6 to a CCGT in 2030 would increase costs, making a rate increase necessary in the near-term. Moreover, the inclusion of the SMR in 2035 with CEI South as an off taker makes this portfolio the highest cost portfolio, approximately 20% higher than the least cost portfolio. The temporary capacity surplus from 2030 to 2034 allows the opportunity for significant capacity and energy sales, helping offset a portion of the cost of this advanced nuclear technology. This portfolio is among the highest ranking in terms of capacity and energy sales, thus representing a significant cost risk with potential for the NPVRR to increase even further if revenues do not materialize.

Figure 4-12 – F.B. Culley 3 on Coal to Small Modular Reactor Results Dashboard

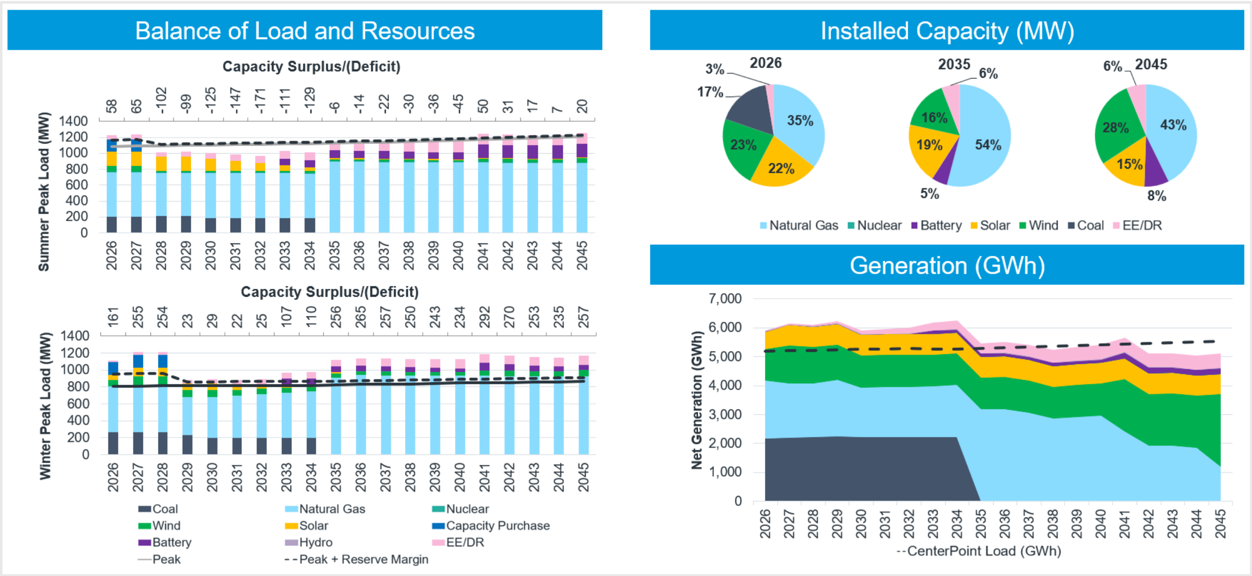


4.3.5. F.B. Culley 3 to Simple Cycle Gas Turbine

This fifth portfolio examines the replacement of CEI South's final coal-fired generating unit that it operates, F.B. Culley 3, with a new 385 MW SCGT. The retirement of F.B. Culley 3 at the end of 2034 is intentionally aligned with the in-service date of the new gas unit, which would begin operation in early 2035. In the absence of converting A.B. Brown 5 and 6 to a combined-cycle configuration (A.B. Brown 7), the portfolio experiences a temporary capacity shortfall that is addressed through the addition of a 100 MW battery storage resource in 2033. Additional wind and battery resources are introduced in the later years of the study to meet growing energy and capacity requirements. Figure 4-13 summarizes the simulated results for this portfolio under Reference Case conditions.

This portfolio maintains flexibility by keeping A.B. Brown 5 and 6 units as combustion turbines and deferring the replacement of F.B. Culley 3 to the beginning of 2035. This reduces risk from changes in regulations and market conditions, reduces the need for near-term investment, and keeps the near-term incremental energy burden low. The addition of storage and wind resources to meet capacity and energy needs over time allows for increased renewable reliance but also increases cost in the long-term, leading to a 20-year NPVRR that is 16% greater than the least-cost portfolio. Because the portfolio is highly reliant on gas combustion turbines, it faces risk associated with gas cost, capacity, availability of gas, and pipeline regulations that could potentially increase the portfolio's already high long-term cost.

Figure 4-13 – F.B. Culley 3 to Simple Cycle Gas Turbine Results Dashboard

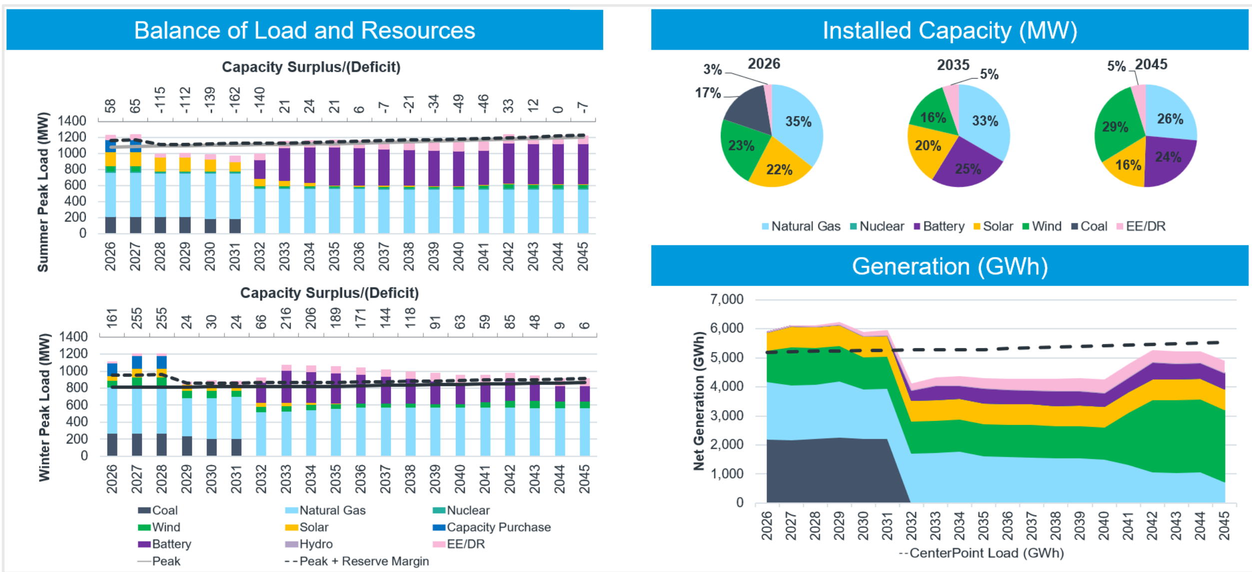


4.3.6. Renewable Heavy Portfolio

This portfolio examines a pathway in which CEI South meets its long-term capacity and energy needs primarily through renewable and storage resources while still maintaining existing thermal gas units. In this portfolio, F.B. Culley 3 retires at the end of 2031, and the model immediately replaces that capacity with 300 MW of 4-hour storage resources in 2032. As the study period continues, the model adds additional storage and wind resources for a cumulative total of 600 MW of storage capacity and 400 MW of wind capacity. The balance of load and resources shown in Figure 4-14 illustrates that this portfolio is generally short on capacity during the summer despite substantial renewable additions. This reflects the declining capacity accreditation of intermittent technologies, which is accelerated under MISO's Direct-Loss-of-Load methodology. The figure also shows that the portfolio is reliant on energy purchases from the retirement of F.B. Culley 3 at the end of 2031 until the end of the planning horizon.

While the rate impact of this portfolio is limited until 2032 due to minimal capital investments and the inclusion of tax incentives before IRA sunset, the long-term cost and cost risk in this portfolio are high. The portfolio is heavily reliant on market capacity purchases in the near-term and energy market purchases in the long-term, a major risk associated with this portfolio. Future uncertainty around MISO's accreditation could result in even greater capacity deficits. The portfolio is relatively environmentally friendly with low CO_2 emissions, but that comes with execution risk from procuring the amounts of storage and wind needed for this portfolio to function. The loss of interconnections at F.B. Culley 2 and F.B. Culley 3 also make this portfolio inflexible and less able to adapt to regulatory and market conditions.

Figure 4-14 – Renewable Heavy Portfolio Results Dashboard

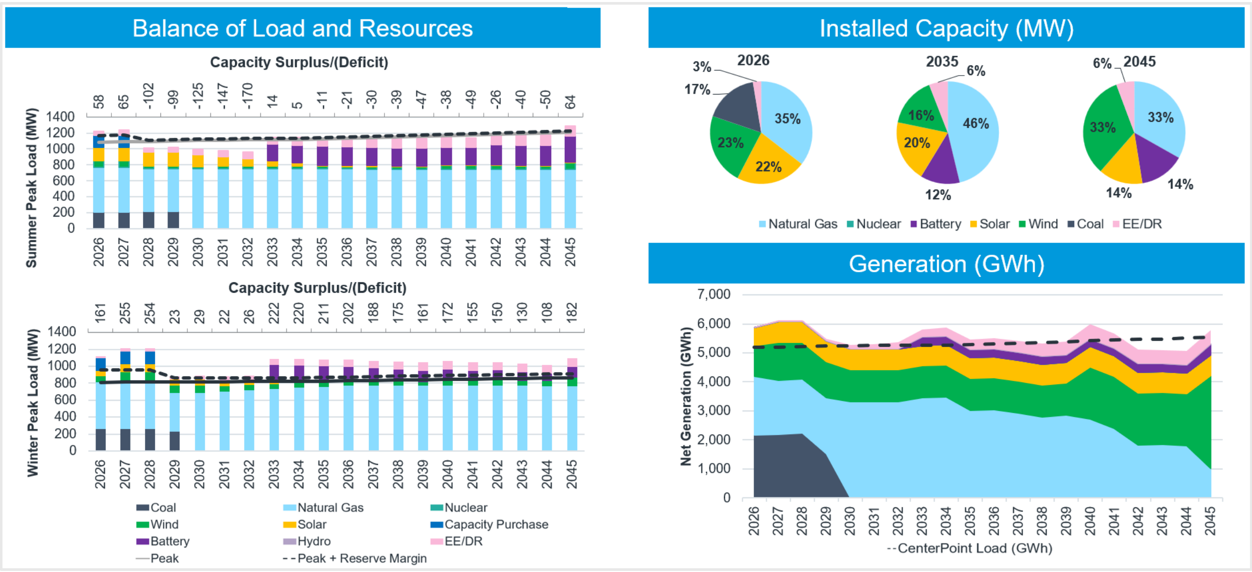


4.3.7. F.B. Culley 3 Gas Conversion with Renewables

This portfolio evaluates the conversion of F.B. Culley 3 from a coal resource to a natural gas-fired unit at the beginning of 2030. This portfolio does not utilize the interconnect at F.B. Culley 2 and does not convert the A.B. Brown 5 and 6 combustion turbines to A.B. Brown 7. Without additional capacity at those existing sites, this portfolio adds firm capacity to the portfolio through additional storage resources in 2033. Similar to previous portfolios, additional wind and storage resources are built in the later years of the study period to meet future energy and capacity needs. As shown in Figure 4-15, as the new resources continue to come online, the generation from F.B. Culley 3 generally declines.

This portfolio has moderate overall emissions released, with the lowest SO_x emissions but the second highest NO_x emissions. Despite the high NO_x emissions, the portfolio is generally well positioned in case environmental regulations change because of its renewable emphasis and the early conversion of F.B. Culley 3. However, the portfolio is among the highest cost portfolios with a high incremental energy burden in both the near and long-term. Additionally, for most years of the planning horizon, this portfolio falls short on accredited capacity, which exposes CEI South to capacity market price swings and represents a risk as renewable accreditation continues to change.

Figure 4-15 – F.B. Culley 3 Gas Conversion with Renewables Results Dashboard



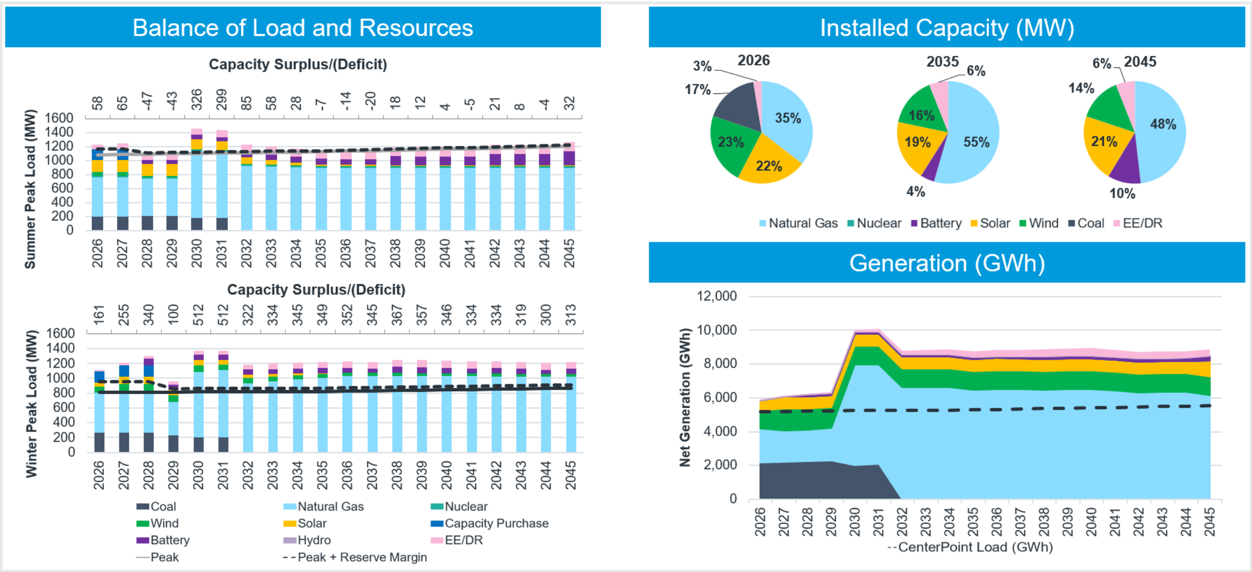
4.3.8. Low Regulatory Portfolio

As mentioned previously, there are three scenario-driven portfolios that are the optimized model results from running the various scenarios. This portfolio represents the optimized outcome under the Low Regulatory scenario, which assumes higher load growth and lower capital costs relative to the Reference Case, driven by reduced regulatory pressure and stronger economic forecasts. Under this scenario, natural gas prices grow modestly while capital cost curves for new construction remain comparatively low.

This portfolio reuses the interconnection at F.B. Culley 2 for a 90 MW battery storage project, which comes online at the beginning of 2028. This portfolio also selects to convert the A.B. Brown 5 and 6 to A.B. Brown 7 in 2030 while retiring F.B. Culley 3 at the end of 2031. Similar to the reference case, additional storage resources are added to the system in 2038 and 2042, indicating the need for long-term capacity on CEI South's system. Finally, in the last year of the study, the model selects a hybrid solar plus storage resource to address the accelerated load growth in this scenario. Pairing the solar resource with storage allows for additional solar produced during the midday hours to be stored and used during peak times. Figure 4-16 displays the results of how the low regulatory portfolio performs under reference case assumptions.

Because it relies heavily on a highly efficient combined cycle gas turbine ("CCGT") at A.B. Brown and reuses the F.B. Culley 2 interconnection for storage, portfolio 8 is relatively inexpensive. Although its NPVRR is only 1% greater than the lowest NPVRR portfolio, the early conversion of A.B. Brown does necessitate a near-term rate increase. The portfolio has among the highest energy sales, which introduces a risk that NPVRR could increase if MISO energy market conditions change. This portfolio has moderate overall emissions, though it has the lowest NO_x emissions rate.

Figure 4-16 – Low Regulatory Portfolio Results Dashboard



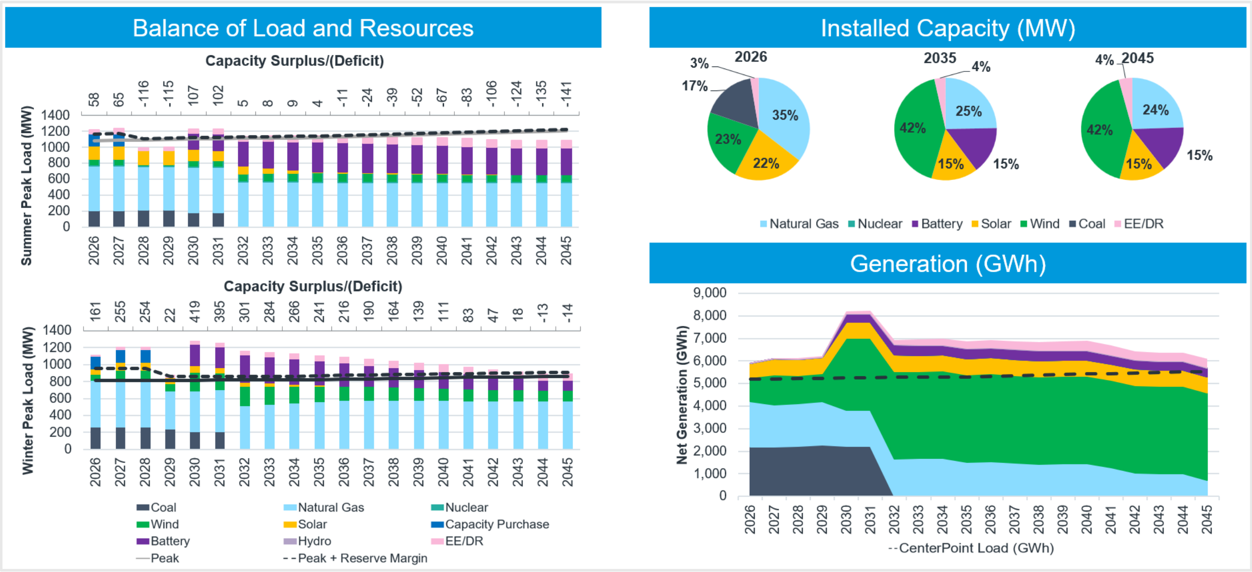
4.3.9. High Regulatory Portfolio

In the High Regulatory scenario, load is assumed to grow at a reduced rate compared to the Reference Case. It has increased fuel prices and lower capital costs for generation resources. Additionally, this scenario includes environmental regulation based on the Clean Air Act (CAA) 111(b) for new gas resources and includes its expansion to existing gas resources, limiting all new and existing gas resources to a 40% annual maximum capacity factor. Moreover, the inclusion of the CAA 111(d) restricts the options for F.B. Culley 3 to either co-fire or convert to natural gas by 2030 or retire by 2032. During the optimization under this scenario, the model selected to retire F.B. Culley 3 at the end of 2031 and continue operating A.B. Brown 5 and 6 without a conversion. The model chooses to fill the capacity and energy gap entirely through hybrid wind and storage resources, for a cumulative total of 800 MW of wind and 400 MW of storage by 2032. Figure 4-17 shows the performance of the high regulatory portfolio under reference case assumptions. Note that since this portfolio is developed to meet a lower load growth, when it is simulated with

Reference Case assumptions, it has a significant shortfall on capacity in the later years of the study.

The High Regulatory portfolio is environmentally friendly with the lowest CO_2e emissions rate and CO_2e intensity. It is well positioned in case environmental regulations change with minimal fuel cost and regulatory compliance risk because of its strong renewable emphasis and F.B. Culley 3 retirement. With 400 MW of storage resources, this portfolio high relatively high fast start capabilities. However, this portfolio is expensive across all affordability metrics, with a high near- and long-term incremental energy burden and NPVRR. Moreover, the inclusion of such large additions (800 MW of wind and 400 MW of storage) across two years brings a significant execution risk, capacity accreditation risk, and likely congestion risk.

Figure 4-17 – High Regulatory Portfolio Results Dashboard

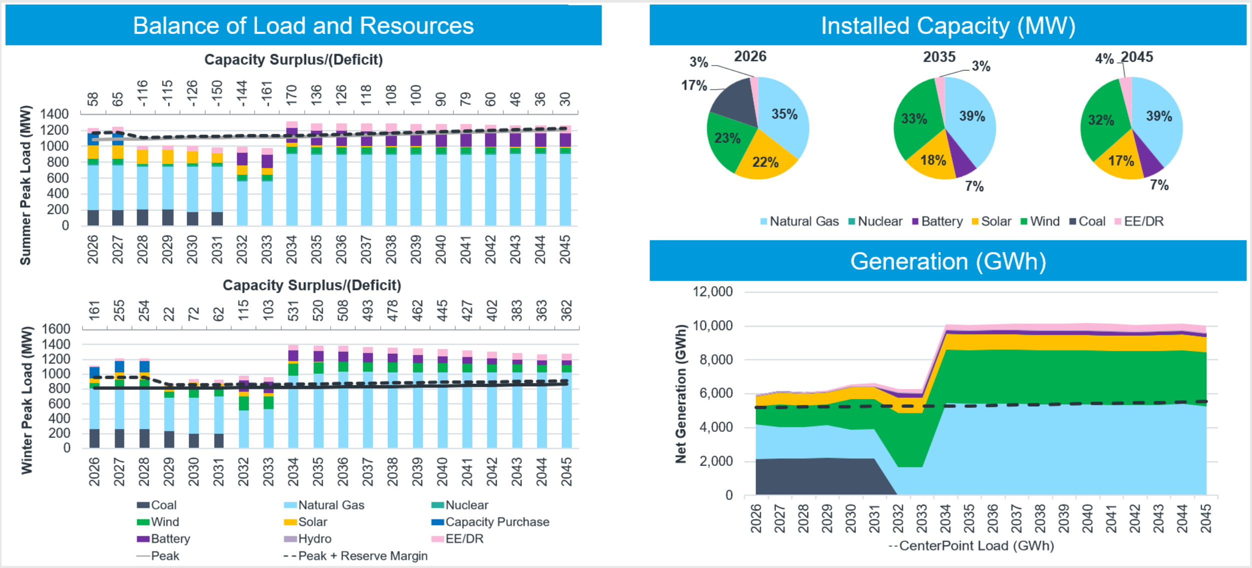


4.3.10. Alternate High Regulatory Portfolio

This portfolio reflects the optimized outcome under the Alternate High Regulatory scenario, which assumes the highest load growth among the scenarios, combined with elevated fuel prices and new resource capital costs. In this portfolio, the interconnection rights expire at F.B. Culley 2 and F.B. Culley 3 retires by 2032 without replacement. The A.B. Brown 5 and 6 combustion turbines are selected to convert to A.B. Brown 7 at the beginning of 2034. To meet long-term energy and capacity needs, the model also selects additional renewable resources, specifically, 600 MW of wind, 200 MW of storage, and 100 MW of solar. As shown in the Balance of Load and Resources chart given in Figure 4-18, the portfolio is long on capacity when simulated under Reference Case assumptions, reflecting the lower load forecast relative to the Alternate High Regulatory scenario.

The Alternate High Regulatory portfolio is moderately high in cost in both near-term energy burden and 20-year NPVRR. It has the third lowest total CO_2e emissions and second lowest CO_2e intensity because of the renewable emphasis and efficiency of the CCGT at A.B. Brown, minimizing environmental regulatory risk. The need for renewables and storage in the near-term does present execution risk, and the portfolio is generally reliant on capacity purchases until the A.B. Brown conversion takes place in 2034.

Figure 4-18 – Alternate High Regulatory Results Dashboard

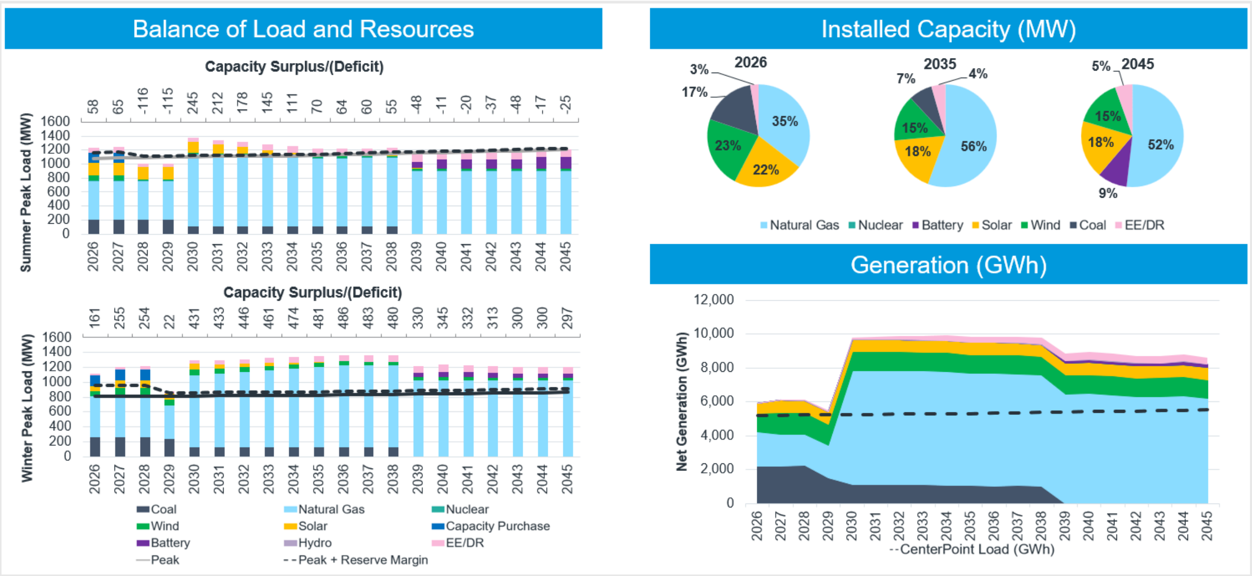


4.3.11. F.B. Culley 3 Co-Fire Portfolio

This portfolio, largely inspired by the regulatory requirements with the Clean Air Act 111, investigates retrofitting F.B. Culley 3 to co-fire with 40% natural gas and 60% coal, until its retirement at the end of 2038. A.B. Brown 5 and 6 convert to A.B. Brown 7 in 2030, which adds additional dispatchability and firm capacity to the portfolio. As illustrated in Figure 4-19, there is excess capacity on the system during the 8 year period in which F.B. Culley 3 is online with A.B. Brown 7. Following the retirement of F.B. Culley 3, the model fills the capacity need with storage resources.

This portfolio is relatively inexpensive as its NPVRR is within 3% of the least-cost portfolio. It is the only portfolio where the incremental energy burden decreases from 2030 to 2035, so while it has a moderate energy burden in 2030, it has the lowest energy burden by 2035. Despite the low overall costs, the two conversion projects are susceptible to execution risk as well as near-term rate increases due to the large capital investments. While the portfolio is consistent with current state and federal near-term objectives to maintain coal, the continuation of F.B. Culley 3 on coal renders this portfolio exposed to future regulatory risk. Additionally, there are operational risks associated with blending fuels.

Figure 4-19 – F.B. Culley 3 Co-Fire Portfolio Results Dashboard



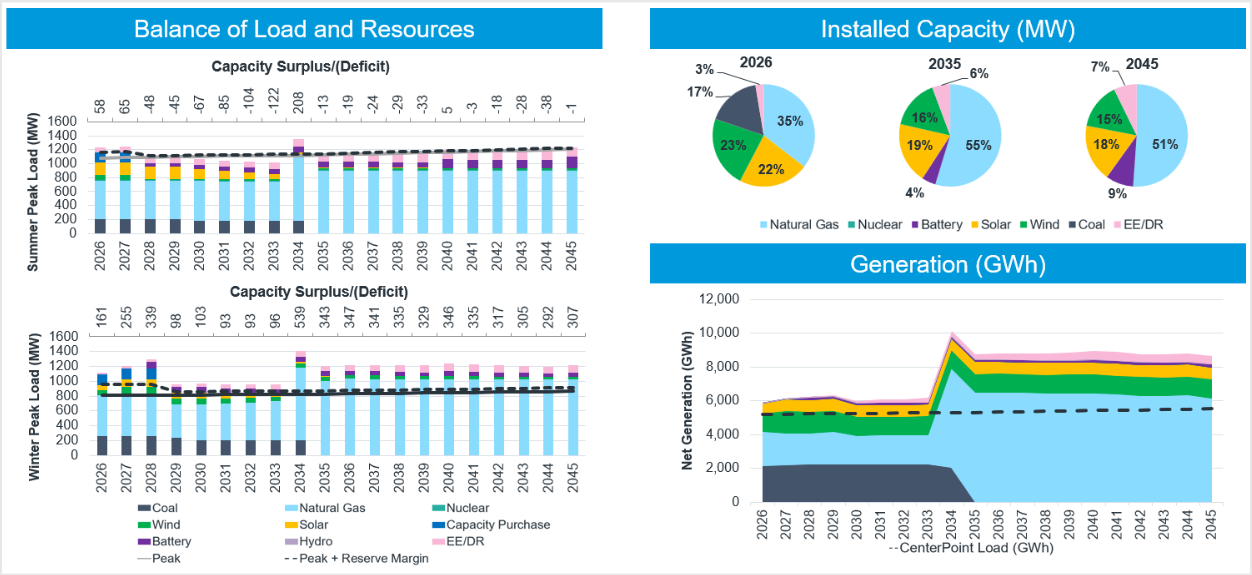
4.3.12. Delayed Reference Case Portfolio

This final portfolio reflects a similar resource plan to the reference case but with delayed timing for major resource decisions to be determined in a future IRP, particularly A.B. Brown 7 which begins operations in early 2034 and F.B. Culley 3 that retires at the end of that same year. By aligning the A.B. Brown 7 conversion date to occur within the same year as the retirement of F.B. Culley 3, the delayed conversion minimizes near-term capital spending and results in less overbuild than the reference case, as illustrated in the Balance of Load and Resources in Figure 4-20.

Additionally, installing a 90 MW battery energy storage resource at F.B. Culley 2 in 2028 leverages existing site infrastructure and interconnection, avoiding future cost risk, while deferring the need for additional capital expenditures for capacity resources until 2040, seven years after the Reference Case begins investing in additional storage. The inclusion of the 4-hour battery at F.B. Culley 2 was tested through a sensitivity analysis, which found that storage resources are more cost-effective than gas options at the site. Furthermore, pursuing a battery at F.B. Culley 2 or a generic storage resource later in the study period resulted in less than a 0.1% difference in total portfolio costs. As such, the F.B. Culley 2 battery project is included in this portfolio.

The delayed reference case is relatively inexpensive with an NPVRR within 3% of the reference case. It has a moderately low incremental energy burden in the near-term and a moderate CO_2e emissions rate. The delay of the conversion for A.B. Brown and retirement of F.B. Culley 3 makes this portfolio highly flexible, awarding additional time to reassess and adapt to changing regulatory, economic, and market landscape.

Figure 4-20 – Delayed Reference Case Portfolio Results Dashboard



The Preferred Portfolio

Chapter 5

5.1. Preferred Portfolio Recommendation

Based upon several factors, CEI South's Preferred Portfolio is the Delayed Reference Case.

5.1.1. Description of the Preferred Portfolio

The Preferred Portfolio includes a combination of new and existing supply- and demand-side resources designed to balance affordability, reliability, and environmental performance. Supply-side additions include a 90 MW battery at F.B. Culley 2 by 2028, conversion of A.B. Brown 5 and 6 (850 MW) in 2034, and retirement of F.B. Culley 3 (270 MW) by 2035, along with an additional 100 MW of storage between 2040 and 2045. These supply-side resources are complemented by demand-side resources: demand response and energy efficiency. These demand-side resources include seven near-term programs (2026–2027) from the approved plan, along with twenty additional programs across the commercial, residential, and income-qualified sectors over the remainder of the planning horizon. Collectively, these programs account for 46 MW of capacity in the first year of the study period and increase steadily to 156 MW by 2045.

The Preferred Portfolio (Delayed Reference Case) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The Preferred Portfolio was within 3 percent of the lowest-cost portfolio. It ranked 3rd out of 12 portfolios in the 95th percentile cost risk metric. It does not over-rely on purchases or sales of energy or capacity. The Preferred Portfolio maintains 270 MW of reasonably low-cost, dispatchable capacity to support CEI South customers during the worst weeks of each season, providing a physical hedge against high energy prices during peak periods. It also capitalizes on the ability to reuse the interconnection at F.B. Culley 2 while allowing time to reassess regulatory and market conditions during the next IRP.

Importantly, it provides flexibility and optionality as MISO adapts to higher future levels of renewables across the system, allowing more time for other technologies, like long-duration battery storage and small modular reactors, to be commercialized. The ability to retire F.B. Culley 3 provides CEI South with a structured pathway to shift toward a lower-carbon portfolio as technology and regulatory conditions evolve.

The Preferred Portfolio is among the best performing portfolios across multiple measures on the scorecard and provides several additional benefits to CEI South customers and other stakeholders, including that it:

- Presents an affordable portfolio for customers as it limits near-term capital investment resulting in a relatively low incremental energy burden. Of the top five least-cost portfolios, the Preferred Portfolio shows the smallest range of expected revenue requirements, indicating that it has less price volatility.

- Includes a diverse mix of resources—solar, wind, and energy efficiency—supported by dispatchable generation, storage, and demand response resources; protects against overreliance on the market for energy and capacity.
- Maintains flexibility with multiple off-ramps to adapt to a rapidly evolving industry, including a multi-year resource buildout across several sites and the option to replace F.B. Culley 3 as technology and market conditions change. This flexibility also enables CEI South to respond to new economic development opportunities.
- Hedges against future cost risks and uncertainty by maintaining the F.B. Culley 2 and F.B. Culley 3 interconnection rights.
- Maintains tax base in Warrick County, which is particularly important to the local school system in that county. Moreover, the Preferred Portfolio adds jobs and tax base to Posey County in 2034.
- Allows for continued use of existing plant assets, helping to avoid future potential stranded assets.
- Continues CEI South's energy efficiency programs with near-term energy savings of 1.18% of eligible sales over the next 6 years, and further long-term energy savings opportunities of 1.17% of eligible sales identified over the remaining 14 years of the 20-year period. CEI South is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Continues existing demand response programs, including the DLC Residential AC Switch Program, Residential Bring Your Own Thermostat ("BYOT", also known as the Thermostat Load Control Rider), and the approved Aggregation Demand Response Program launched in September 2025. The portfolio also continues implementation of CPP Time-of-Use rates beginning in 2028; note that the residential pilot is expected to begin in Q2 2026. In addition, a new Commercial Bring Your Own Thermostat program will be introduced, operating consistently with the existing residential thermostat program.

5.1.2. Reliability

Reliability is commonly measured by the ability of a system to meet load without unserved energy. In the probabilistic Risk Analysis, the Preferred Portfolio was tested through Reference Case assumptions as well as different elements from the three alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load, and capital costs. In each of these simulations, the Preferred Portfolio consistently met MISO's seasonal PRMR and experienced negligible hours of unserved energy. These results confirm that the portfolio provides reliable service under both expected and stressed operating conditions over the 20-year study horizon.

In the near-term, the portfolio contains two highly dispatchable combustion turbines totaling 460 MW. These units provide fast-ramping capability and can reach full output within ten minutes, offering essential backup to variable renewable generation and serving as a hedge against volatility in both the energy and capacity markets. Following the conversion of these combustion turbines to a combined cycle in 2034, ramp times will lengthen to about 30 minutes, but overall thermal efficiency will increase significantly and have the ability to follow load.

Complementing these units is 90 MW of storage beginning in 2028 along with an additional 100 MW of storage by the end of the study period. These storage resources can dispatch at full output in less than one minute, providing immediate response to fluctuations in renewable output or system contingencies. The portfolio also retains 180 MW of existing combustion turbines, one of which provides black start capability, ensuring resilience during grid restoration or multi-day low-renewable conditions. Collectively, these resources enable the system to meet peak demand during periods of limited solar and wind production and to maintain service during seasonal high-risk weeks.

While not an explicit objective in the balanced scorecard, resource diversity supports reliability by reducing dependence on any single fuel or technology. The Preferred Portfolio achieves a balanced mix of peaking and baseload natural gas, solar, wind, battery storage, and demand-side resources. This diversity mitigates risks such as an extended cloudy period (reducing solar generation) or a fuel disruption that can come from a force majeure event on a gas pipeline that could otherwise compromise system reliability.

CEI South has signed a contract with Enel X to add commercial and industrial demand response resources through the approved Aggregation Demand Response rider. 12 MW were included in the Preferred Portfolio in 2026, increasing to 25 MW in 2027, and CEI South has received twenty customer letters of authorization to begin sharing interval meter data for potential program enrollment. Additionally, CEI South's AMI system is being further developed to allow for a time-based rate. CEI South is currently developing a pilot program for a voluntary critical peak pricing rate. CPP better aligns the price customers pay for electricity with the cost of producing it by varying the price of electricity based on the time it's consumed. Customers are charged more for electricity during certain periods of peak demand, encouraging customers to use less energy during critical times. Customers who participate have the opportunity to lower their overall electricity spending by shifting load to lower cost hours. As generation becomes more intermittent and less controllable, it will be more important to shape load in the future. These demand-based options will help to further diversify CEI South's resource mix.

The Preferred Portfolio also includes a significant amount of local resources, namely the assets at the F.B. Culley and A.B. Brown sites. Local projects provide voltage support, physical hedging against high market prices, and reliability for CEI South's large industrial customers, who comprise nearly half of total load. Local generation also reduces the need to construct new high voltage power lines to bring clean renewable power to our area. These transmission projects take years to complete, often require eminent domain and ultimately cost customers money.

CEI South worked with 1898 & Co. to conduct an analysis and review reliability for several alternative paths at existing CenterPoint sites. This near-term assessment reviewed thermal loadings, voltage, VAR support, and transfer capability. Minimal mitigations were identified in the case of F.B. Culley 2 storage, F.B. Culley 3 remaining operational, and the A.B. Brown generation conversion to a combined cycle. For additional study details, see *Technical Appendix Attachment 2.3 Transmission Study (Confidential)*.

5.1.3. Resilience

The Preferred Portfolio offers CEI South customers a blend of renewable energy along with highly efficient, dispatchable thermal generation to maintain system reliability under a range of operating conditions. The combustion turbines currently at A.B. Brown will continue to offer fast ramping capability when needed. When they transition to baseload resources, following the conversion, they will provide additional spinning reserve benefits by supporting system frequency and replacing generation during sudden outages. The continuation of F.B. Culley 3 through the end of 2034 enhances near-term resilience by supplying dependable, dispatchable capacity and spinning reserve benefits. These dispatchable resources are critical to grid resilience, particularly when intermittent resources experience long duration droughts, periods of sustained high demand, or potential future winter weather events. The Preferred Portfolio also includes a combustion turbine with black start capability, offering an additional degree of increased resiliency and operational flexibility.

The chosen portfolio also maintains both of the existing interconnection rights at F.B. Culley 2 and 3, for 90 MW and 270 MW, respectively. This protects customers from untimely delays associated with a generation resource at another location, especially with the extensive MISO queue delays in recent years due to the record amount of interconnection requests submitted. In addition, it shields customers from potential transmission upgrade costs because the increase in interconnection requests is exhausting available transmission capacity. In addition to preserving these rights for future replacement resources, the continued operation of F.B. Culley 3 provides valuable spinning mass on

CEI South's system, supporting local grid frequency. This makes the local grid more resilient to sudden system disturbances.

5.1.4. Stability

A transmission analysis was performed on four unique groups defined by the operational status of F.B. Culley 3 (retirement or continued operation) and A.B. Brown 5 and 6 (conversion or no conversion). As described in Section 2.8.3.1, short circuit ratio ("SCR") and dynamic reactive power ("VAR") support were used as the primary transmission metrics to assess system stability. The Preferred Portfolio, which includes the conversion of A.B. Brown 5 and 6 at the beginning of 2034 as well as the retirement of F.B. Culley 3 at the end of that same year, performed well in both stability metrics. Notably, the Preferred Portfolio has the second highest dynamic VAR support, indicating strong voltage stability during and after major grid disturbances.

In addition to the scoring assessment, a more detailed transmission study evaluated the system impacts of individual unit retirements and additions. The study found that if F.B. Culley 2 were to retire and no other units were brought online, the transmission system would require about $47.9 million in upgrade costs. These upgrade costs were incorporated into the Preferred Portfolio's NPVRR, recognizing that these expenses could be incurred if the site's planned battery storage remains idle. Including this assumption ensures that the Preferred Portfolio reflects a prudent estimate of potential transmission investment needs.

5.1.5. Environmental Sustainability

The Environmental Sustainability objective was evaluated utilizing the stochastic analysis and is quantified using four metrics:

- CO_2 equivalent emissions (stack emissions) intensity (tons of CO_2e/kWh)
- CO_2 equivalent emissions (tons of CO_2e)
- SO_x emissions (tons of SO_x)
- NO_x emissions (tons of NO_x)

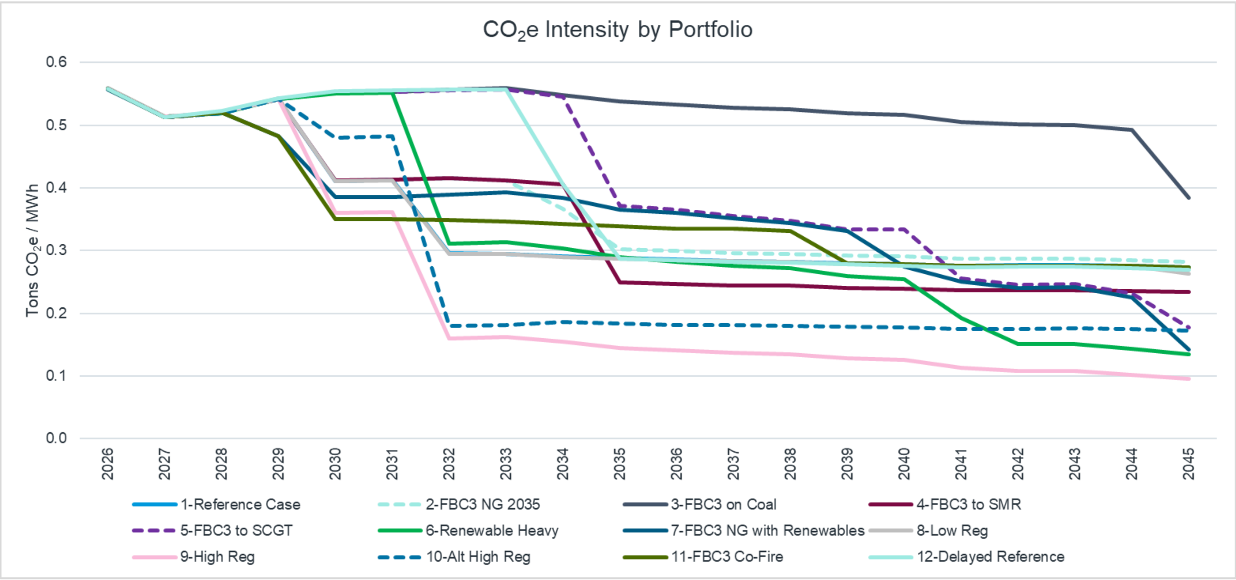
The inclusion of CO_2e is useful as it measures not only CO_2 but other emissions, such as methane and nitrous oxide. Conversion factors were applied to CO_2 from the Electronic Code of Federal Regulations ("eCFR")[39,40] to convert to CO_2 equivalence. All metrics measure the total amount of pollutants that go into the atmosphere over the 20-year planning period rather than at a given point in time.

[39] Methane (CH4) and nitrous oxide (N2O) emission factors for coal (bituminous) and natural gas taken from Table C-1 to Subpart C of 40 CFR Part 98. December 9, 2016.
[40] Chemical-specific Global Warming Potentials ("GWPs") taken from Table A-1 to 40 CFR Part 98 Subpart A for a 100-year time horizon. December 11, 2014.

The Preferred Portfolio performs moderately well in the Environmental Sustainability objective, reducing annual CO_2e emissions by more than 7 million tons over the 2026-2045 study period compared to the BAU portfolio (Portfolio 3). As illustrated by Figure 5-1, the retirement of F.B. Culley 3 at the end of 2034 causes a significant drop in total emissions. During the same year, the conversion of A.B. Brown 5 and 6 combustion turbines to a highly efficient combined cycle also contributes to declining emissions.

By 2035, the Preferred Portfolio was found to reduce CO_2 emissions in the reference case by approximately 72% compared to the baseline year of 2005. This represents an annual reduction of approximately 7.5 million tons of CO_2 from the baseline of 9.6 million tons of CO_2, with the small remainder driven mostly by the A.B. Brown units.

Figure 5-1 – Average CO_2e Emissions Intensity across 200 Draws



5.1.6. Affordability

Affordability is a key objective in the balanced scorecard that is measured as part of the stochastic analysis. The primary measure for affordability is the 20-year NPVRR, which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is simulated in the dispatch model under varying market conditions. Each iteration provides the total annual cost of each component of total portfolio cost, including fuel costs, emissions costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenues (sales), energy import costs (purchases), capacity market sales revenues, and capacity market purchase costs. Each annual cost category is then summed into a total portfolio cost and discounted by CEI South's weighted average cost of capital to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be to recoup the cost to serve load over the next 20 years. The stochastic methodology allows for a rigorous analytical framework to determine the affordability of a portfolio.

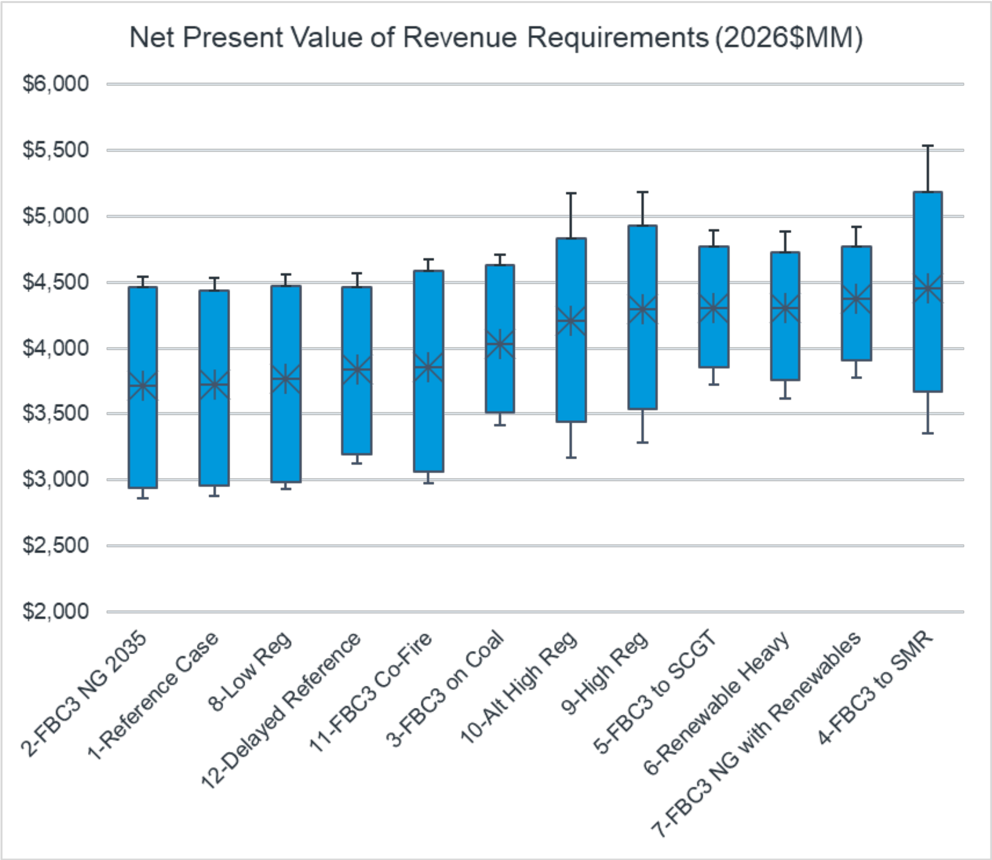
The Preferred Portfolio is within the least-cost portfolios and performs well in the other quantitative affordability metrics including 5th and 95th percentiles of NPVRR and incremental energy burden. Beyond the NPVRR, the Preferred Portfolio mitigates future cost risk through moderate reliance on energy and capacity market sales and using local resources, which have an additional benefit.

5.1.6.1. Portfolio Cost Comparison

Figure 5-2 summarizes NPVRR outcomes from 200 stochastic iterations for each portfolio, showing the minimum, the fifth percentile, the average (indicated by the star), the ninety-fifth percentile, and the absolute maximum. As illustrated in the figure, the Preferred Portfolio has the narrowest range of possible NPVRRs of the top 5 least-cost portfolios. This indicates less variability in future portfolio costs, revealing cost stability among changing market conditions. The 5th percentile of costs is approximately \$3.2 billion while the 95th percentile is approximately \$4.5 billion, meaning that 90% of the 200 runs created a total net present value of revenue requirements between those two values.

The Preferred Portfolio is among the lowest cost portfolios across the 12 candidates, with a 20-year average NPVRR of \$3,836 million. This NPVRR is within 2.9% of the Reference Case portfolio and 3.2% of the least cost portfolio. The Preferred Portfolio is nearly \$200 million less expensive than BAU which continues F.B. Culley 3 on coal (the sixth most expensive portfolio in this objective category), which saves customers money in the long-term. Moreover, if sales revenues come in as modeled, the incremental energy burden shows a minimal increase in affordability over both the near and long-term.

Figure 5-2 – Net Present Value of Revenue Requirements for All Portfolios



5.1.6.2. Future Affordability

Moreover, of the top 5 least-cost portfolios, the Preferred Portfolio shows the least reliance on future energy and capacity market sales to lower the NPVRR and make the portfolio more competitive. The greater the energy market sales by a candidate portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market purchases that are required by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be higher than the cost of adding capacity to the CEI South fleet.

Figure 5-3 displays the near-term maximum, short-term maximum, and planning horizon average energy market sales expressed as a percent of total generation as well as the net present value of total capacity market sales in dollars. As seen in the Figure 5-3, four of the top five portfolios have an average of 26% of generation contributing to sales and a near-term maximum of 32%. As explained above and validated by the Indiana Commission in

Cause No. 45052, this is a risky proposition for a company of this size. In contrast, CEI South's Preferred Portfolio (12-Delayed Reference) sells a maximum of 17% of total generation in the near-term and averages 23% over the entire study period. Thus, even with lower energy market sales exposure, the Preferred Portfolio's total cost (NPVRR) remains within 3% of the least-cost portfolio.

Figure 5-3 – Portfolio Exposure to Market Sales

Portfolio	Energy Market Sales (%)			Capacity Sales NPV ($M)
	Average	Short Term Max	Long-term Max	
2-FBC3 NG 2035	26%	32%	31%	$217
1-Reference Case	26%	32%	30%	$140
8-Low Reg	26%	32%	30%	$167
12-Delayed Reference	23%	17%	31%	$115
11-FBC3 Co-Fire	26%	32%	31%	$192
3-FBC3 on Coal	15%	18%	18%	$117
10-Alt High Reg	25%	20%	32%	$159
9-High Reg	20%	26%	23%	$128
5-FBC3 to SCGT	14%	17%	18%	$93
6-Renewable Heavy	11%	16%	13%	$95
7-FBC3 NG with Renewables	14%	17%	19%	$106
4-FBC3 to SMR	26%	32%	31%	$171

In contrast, overreliance on market purchases also carries inherent risk. The greater the energy market purchases that are required by a candidate portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk, if capacity market prices are lower than forecasts the NPV reduction from capacity sales would be lower.

As shown in Figure 5-4, the Preferred Portfolio is moderately reliant on energy market purchases, which, on average over the planning horizon, was about 12% of total generation. While the other least-cost portfolios only had about 10% of total generation from market sales, this is due to the earlier conversion of A.B. Brown, which necessitates a near-term rate increase. With regard to capacity market purchases, the Preferred Portfolio also performs moderately well. In the first four years of the study, this portfolio has the smallest capacity deficit, largely due to the addition of the firm capacity associated with the F.B. Culley 2 battery. While the ten portfolios that allow for the interconnection rights to expire at F.B. Culley 2 are forecasted to purchase nearly $5 million worth of capacity in 2028 and 2029, the Preferred Portfolio purchases are about half of that during the same time period. Thus, while the Preferred Portfolio includes moderate capacity purchases over the long-term, CEI South will continue to evaluate this path and prioritize affordability following submission of this IRP.

Figure 5-4 – Portfolio Exposure to Market Purchases

Portfolio	Energy Market Purchases (%)			Capacity Purchases NPV ($M)
	Average	Short Term Max	Long-term Max	
2-FBC3 NG 2035	9%	16%	9%	$6
1-Reference Case	10%	17%	11%	$14
8-Low Reg	10%	17%	11%	$6
12-Delayed Reference	12%	21%	11%	$18
11-FBC3 Co-Fire	10%	22%	11%	$12
3-FBC3 on Coal	19%	21%	26%	$22
10-Alt High Reg	9%	17%	5%	$19
9-High Reg	14%	17%	16%	$23
5-FBC3 to SCGT	21%	20%	29%	$26
6-Renewable Heavy	30%	37%	40%	$22
7-FBC3 NG with Renewables	23%	26%	30%	$24
4-FBC3 to SMR	9%	16%	8%	$13

5.1.6.3. Broader Affordability Impacts

Moreover, since the Preferred Portfolio proposes a significant amount of resources located within CEI South's service territory, the customers benefit from reduced congestion cost risk and additional tax base and jobs. Local generation helps to minimize the risks of differences in cost between where power is produced and where it is consumed. When power is produced on system, customers minimize the likelihood of congestion charges, which can occur when delivering power via the transmission system.

Investing in local projects also helps produce tax base and jobs, which directly benefit the communities CEI South serves. Currently, CEI South primarily operates generation assets in two counties, generating tax revenues in Posey and Warrick counties. The Preferred Portfolio replaces F.B. Culley 2 with a battery storage system, which provides economic benefit to the local community, whereas simply purchasing the capacity from the market does not. Moreover, the Preferred Portfolio provides additional tax base in Posey County due to the A.B. Brown 5 and 6 conversion. Communities where CEI South customers live can utilize this money to support school systems, police, parks and recreation, and other critical support services. Additionally, these projects will continue to be operated by local employees that contribute to the local economy. Finally, the continued operation of F.B. Culley 3 on coal preserves the local tax base and contributes to Indiana's economy through the use of Indiana-mined coal and the associated mining employment.

5.1.7. Other

5.1.7.1. Future Flexibility

The Preferred Portfolio provides a low-cost plan with a great deal of forward-looking flexibility. The inclusion of the battery storage resource at F.B. Culley 2 addresses CEI South's capacity need while also maintaining a valuable MISO interconnection. Maintaining the interconnection avoids future cost risk. This portfolio provides time for other technologies to advance and potentially become more cost competitive as CEI South will reevaluate decisions at F.B. Culley 3 and at A.B. Brown 5 and 6, in a future IRP. This time also allows CEI South to adapt to changing regulatory and market conditions. Until such time, CEI South customers will benefit from the minimal capital investments in the near-term, providing rate stability.

5.1.7.2. Operational Flexibility

In the near term, the Preferred Portfolio includes Variable Energy Resources ("VER") in the form of nearly 400 MW each of solar and wind, balanced by 190 MW of energy storage resources and two 230 MW natural gas combustion turbines that transition into an 850 MW combined cycle gas turbine in 2034. The CT units, batteries, and CCGT can help to smooth out the intermittency of the VERs. The fast-ramping requirements of a system increase as the balance shifts toward increased VERs, particularly solar resources. The phenomenon known colloquially as the "duck curve" demonstrates the need for fast-ramping capability, a role that fast-start resources perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Moreover, the dispatchable CCGT will provide critical baseload and load-following capability along with a lower emission profile. The high thermal efficiency and quick ramping capability of the unit will stabilize the net load variability and deliver reliable power during extended periods of low wind or solar production. This portfolio is expected to meet all operational flexibility requirements.

Following the conversion of the A.B. Brown combustion turbine units 5 and 6 to a CCGT, CEI South will retain a diverse and flexible set of natural gas units as it will maintain its' existing two 80 MW CT's. These peaking units can be brought online relatively quickly to address short-term fluctuations in demand, complementing the steady output of the CCGT. One of the two peaking units includes black start capability, providing operational flexibility. Maintaining both technologies strengthens operational flexibility, ensuring reliable service across a range of potential market and system conditions.

CEI South considers maintaining an adequate amount of dispatchable generation essential to ensuring reliable service for customers throughout all seasons and operating conditions. CEI South's experience shows that renewable generation can be unpredictable, therefore, a portion of generation should (a) provide a dispatchable (controllable) output (b) be able to start and stop more than once daily and be placed in service quickly and (c) respond to rapid changes in renewable output. Given the healthy number of dispatchable resources in the Preferred Portfolio, CEI South is not only able to meet current system needs but is positioned well to continue to investigate the addition of more intermittent generators on the system should the need arise.

5.1.7.3. Economic Development

The Preferred Portfolio positions CEI South well to provide relatively low-cost power to industrial customers and other large load users. The current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, CEI South must remain nimble and dynamic for prospective industrial customers and planning for the conversion of A.B. Brown 5 and 6 to a CCGT in 2034 provides this agility. CEI South aggressively pursues manufacturing opportunities which have direct, indirect, and induced economic benefits for the region and state of Indiana. CEI South's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunities for residents and at the same time raises state revenue and tax base. Additionally, large power users can assist all CEI South customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

For industrial customers to maintain their required voltage level, the CEI South system must be able to supply an adequate amount of reactive power ("VARs"). Transmission planning studies have shown that this cannot be accomplished without on-network reactive power supplying facilities, such as local synchronous generation. The CTs in the Preferred Portfolio provide reactive power support. Even when they are not dispatched normally, CTs are able to be started and brought online quickly if needed for CEI South system reliability. Moreover, when the A.B. Brown CTs are converted to a baseload combined cycle in 2034, the dynamic reactive power on the system increases. The A.B. Brown CTs as well as the CCGT also prevents CEI South from entering into Reactive Power Payments through the MISO market, which would impact CEI South customers' bills.

In addition, large customers and site selectors understand the comprehensive risks of market rate pricing and the corresponding volatility. The current IRP plan and the opportunity for future baseload generation allows for customers to remain confident in CEI South's ability to provide safe, reliable, and cost-effective service. CEI South's generation strategy is an essential service for customers and the region's economic growth capability.

5.1.8. Fuel Inventory and Procurement Planning

Prices for commodities such as coal and natural gas are influenced by market conditions and can vary significantly over time, introducing uncertainty into long-term planning. CEI South manages short-term price volatility through coal contract strategies that lock in prices to stabilize costs. Coal suppliers and transportation providers generally require firm commitments on quantities; however, CEI South coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently CEI South utilizes non-firm pipeline delivery and gas storage for the existing 80 MW peaking units and firm pipeline delivery and gas storage for the new A.B. Brown CTs. It is planned that the combustion turbines at A.B. Brown, if converted, will continue to utilize firm pipeline supply contracts.

The Alternate Preferred Portfolio

Chapter 6

6.1. Alternate Reference Case Portfolio Development

Following stakeholder feedback, the Alternate Reference Case was developed to evaluate the potential for a large load addition that scales over time. In this scenario, the new, additional load increases in 250 MW increments until it reaches 1,500 MW, while all other market assumptions remain consistent with the Reference Case. To support potential economic development opportunities in Southwestern Indiana, CEI South developed multiple portfolios to explore different pathways for serving future large load growth.

Specifically, five portfolios were considered, each designed to test alternate development pathways under the large load growth assumptions included in the Alternate Reference Case. One portfolio, similar to the scenario-based portfolios discussed earlier, was produced by allowing the model to freely optimize resource additions to create the least-cost portfolio that meets input assumptions. The remaining four portfolios were developed to explore different ways to serve an increased load by directing the model toward specified resource selections and then allowing optimization around those decisions.

The resulting portfolios are summarized in Figure 6-1. Across all portfolios, the model selected to reuse the interconnection rights at F.B. Culley 2 to construct a 90 MW storage facility in 2028, securing capacity to meet load growth and taking advantage of the investment tax credit benefits. The model also exclusively chose to convert the A.B. Brown 5 and 6 CTs to a 2x1 CCGT at the earliest opportunity (2030). This conversion is favorable as it converts the peaking CTs to an efficient CCGT that can serve as a baseload resource, while adding nearly 400 MW of firm capacity to the portfolio. Finally, all portfolios also preferred to keep F.B. Culley 3 operational in some capacity, either as a baseload coal resource or a peaking natural gas unit.

Figure 6-1 – Alternate Reference Case Portfolios

Year	1: Optimization Run	2: 1x1 J Class in 2032	3: Renewables + CT's	4: FB Culley 3 NG Conversion 2030	5: FB Culley 3 NG Conversion 2035
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031			+1 Non IRA Wind + Storage (200 + 100 MW)		
2032	+1 2x1 J Class Fired CCGT (1361 MW)	+1 1x1 J Class Unfired CCGT (568 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 2x1 J Class Fired CCGT (1361 MW)	+1 2x1 J Class Unfired CCGT (1144 MW)
2033			+5 Non IRA Wind + Storage (1,000 + 500 MW)		+1 2x1 J Class Fired CCGT (1361 MW)
2034		+1 2x1 J Class Unfired CCGT (1144 MW)	+2 Non IRA Wind + Storage (400 + 200 MW)		
2035	+1 J Class SCGT (385 MW)		+1 J Class SCGT (385 MW)	+1 J Class SCGT (385 MW)	+1 FB Culley:3 NG 2035 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)
2036					
2037			+1 50 MW 4 Hour Storage (50 MW)		
2039		+1 50 MW 4 Hour Storage (50 MW)			
2040	+1 50 MW 4 Hour Storage (50 MW)		+1 F Class SCGT (222 MW)	+1 Non IRA Wind (Battery) (100 MW) +1 Non IRA Wind (Hybrid) (200 MW)	
2041					+1 50 MW 4 Hour Storage (50 MW)
2042	+1 100 MW 4 Hour Storage (100 MW)	+1 50 MW 4 Hour Storage (50 MW)			
2043					+1 50 MW 4 Hour Storage (50 MW)
2044		+1 50 MW 4 Hour Storage (50 MW)	+1 Non IRA Wind (200 MW)		
2045	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Solar + Storage (100 + 50 MW) +1 Reciprocating Engine (110 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)

6.2. Portfolio Performance

The five portfolios were evaluated through a similar risk analysis framework as the traditional portfolios in order to test operational performance and affordability under a range of potential market conditions. The market conditions that were varied include fuel costs, capital costs, inclusion of a CO_2 tax, market prices, and allowable energy sales. The methodology and calculations underlying these variations are described in the Risk Appendix section Risk Appendix. The relative performance of each portfolio across these conditions is detailed in Figure 6-2. The inputs into the EnCompass model that were used to generate the following results is given in the *Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)*.

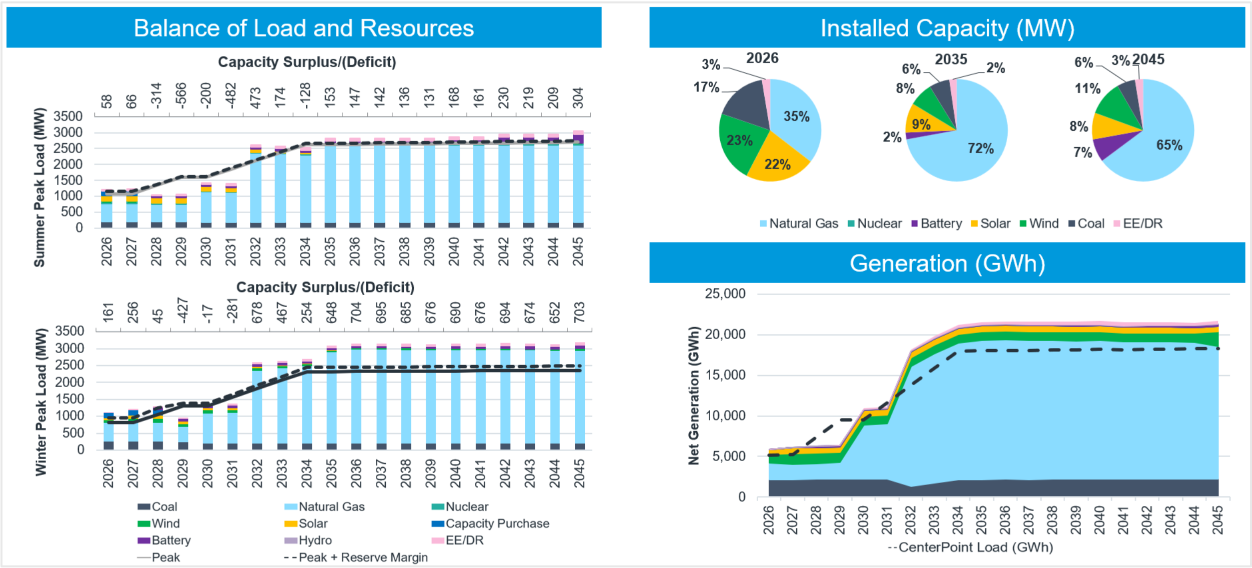
Figure 6-2 – Alternate Reference Case Risk Analysis Scorecard

Objective	Affordability				Environmental Sustainability				Reliability/Resiliency/Stability			Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
1- Optimized Case	$11,652	0%	$10,197	$13,257	0.427	121,201	47,708	26,303	33,860	2,063	614	10.1%	14.2%	$163	$80
2- 1x1 J Class 2032	$12,242	5%	$10,899	$13,674	0.304	93,487	8,890	17,617	41,307	2,227	371	9.7%	14.8%	$122	$112
3- Renewables + CT's	$12,024	3%	$10,510	$13,288	0.335	84,915	51,563	26,813	5,386	1,031	1,269	7.5%	18.1%	$45	$120
4- FBC3 NG 2030	$11,893	2%	$10,573	$13,355	0.304	92,840	9,123	17,187	38,787	2,063	612	9.7%	14.9%	$168	$79
5- FBC3 NG 2035	$11,659	0%	$10,401	$13,119	0.296	82,899	21,563	10,358	25,466	1,868	556	9.7%	14.3%	$130	$100

1: Average net present value of portfolio revenue requirements from 2026 to 2045
2: Percent difference between average NPVRR of portfolio and reference
3-4: Fifth and ninety-fifth percentiles of net present value of NPVRR to show cost uncertainty
5: Quotient of average CO_2e from generation and average fleet generation from 2026 to 2045
6-8: Total CO_2 equivalent, SO_x, and NO_x emissions from 2026-2045
9: Total emergency unserved energy purchased from 2026 to 2045
10: Capacity from "spinning" thermal assets that can be ramped up or down (combined cycle, coal, nuclear)
11: Capacity from "fast start" assets that can be dispatched quickly (combustion turbine, battery)
12-13: Dynamic VAR support and short circuit ratio from transmission reliability analysis
14: Total energy sales as a percentage of total energy generation from 2026 to 2045
15: Total energy purchases as a percentage of total load from 2026 to 2045
16-17: Net present value of capacity sales and purchases from 2026 to 2045

The optimized portfolio (Preferred Portfolio) developed for the Alternate Reference Case ranks as the least-cost option for meeting rapid load growth. This portfolio retains the F.B. Culley 2 interconnection rights by installation of a battery energy storage resource by 2028, avoiding future cost risk and providing additional reliability to the system. It also maintains the operation of F.B. Culley 3 on coal throughout the entire study period. Though this outcome is less favorable from an environmental perspective, it preserves flexibility for CEI South to revisit this critical decision point in a future IRP cycle as regulatory, market, and technology conditions evolve. The 2030 conversion of A.B. Brown 5 and 6 provides benefits beyond energy and capacity, including the creation of additional jobs and tax base in Posey County. As seen in Figure 6-3, the portfolio, similar to all alternate reference case portfolios, relies on market capacity and energy purchases in the short-term. These needs would most likely be filled by fixed capacity or energy contracts.

Figure 6-3 - Alternate Reference Case Preferred Portfolio Results Dashboard



6.2.1. Transmission System Impact of the Large Load Additions

To assess system reliability, a thorough transmission study evaluated the shoulder, summer, and winter scenarios for various possible large loads. This includes a near-term addition of 300 MW and a 1,000 MW on the West side of the transmission system along with a long-term study of 300 MW and a 1,500 MW on either the West or East side of the system. Similar to previously mentioned studies, this was performed using the MTEP 2024 model, PSS/E software for power flow analysis, and the MISO MTEP 2025 cost guide for component price estimates.

The results indicated that the addition of a 300 MW load on either side of CEI South's system did not require upgrades to the transmission system, while the larger loads did necessitate transmission mitigation (See *Technical Appendix Attachment 6.2 Large Load Study Results (Confidential)*). The Preferred Portfolio's inclusion of the A.B. Brown 2x1 combined cycle and additional large thermal resources located on CenterPoint's system led to required transmission mitigation and upgrade costs of $15.2 to $16.4 million. In contrast, if a large thermal resource were not added to the local system, transmission costs would increase roughly tenfold due to the need for major system reinforcements to accommodate heavy power imports from neighboring regions. Specifically, on the West side of the system, a cost of $152 million would be required to serve a near-term 1,000 MW load while a cost of $147 million would be required to serve a long-term 1,500 MW load. These estimates are for the transmission upgrade costs studied in the transmission portfolio and do not include the costs associated with on- or off-system generation needed to meet the energy and capacity needs of the large load.

For a large load located on the East side of the system, there are unresolvable low-voltage issues, indicating a need for a large generator on the system. The costs resulting from this transmission analysis were not factored into the NPVRR, as the location and timing of the load are speculative. Since the costs would affect all generation portfolios evenly, the relative ranking of portfolio performance stands.

6.2.2. Generation Planning for Large Loads

In addition to the Alternate Reference Case portfolios, a series of large load sensitivities were also conducted to evaluate how the timing and magnitude of new load additions influence resource decisions. Load increases of 100 MW, 300 MW, and 1,000 MW were evaluated. The sensitivities were constructed primarily to provide insight into model behavior and were not included in the Risk Analysis. Three important trends emerged during this sensitivity analysis:

1. In all cases, the model selected the conversion of A.B. Brown from combustion turbines to a combined cycle natural gas plant. This conversion adds nearly 400 MW of firm capacity and provides a reliable baseload resource to support opportunities for economic development.
2. For future load additions greater than 300 MW, the preferred pathway at F.B. Culley 3 shifted from retirement to continued operation throughout the entire study period, preserving flexibility for future replacement or conversion.
3. For future load additions greater than 1,000 MW, the decision to install a battery at F.B. Culley 2 became part of the least-cost portfolio. The early procurement of additional capacity increases system flexibility and contributes valuable firm capacity to CEI South.

6.3. Description of the Alternate Reference Case Preferred Portfolio

The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028, calls for the conversion of A.B. Brown units 5 and 6 gas turbines to an efficient CCGT unit by 2030, and continues to operate F.B. Culley 3 on coal. Beyond these resources, the portfolio calls for the addition of a large natural gas combined cycle in 2032 as the load continues to rapidly increase. In the latter years of the planning horizon, a smaller simple cycle gas unit is added in 2035, and a cumulative 150 MW of standalone storage is procured. In the final study year, an additional hybrid wind plus storage facility is brought online to fill energy and capacity needs.

This generation fleet is complemented by energy efficiency and demand response programs. These demand-side resources include the seven near-term (2026-2027) programs included in the previously approved plan, as well as nineteen additional programs across the commercial, residential, and income-qualified sectors throughout the rest of the planning horizon. Collectively, these programs account for 46 MW of capacity in the first year of the study period and scale up to 118 MW by 2045.

The alternate preferred portfolio offers a least-cost and extremely flexible pathway to meeting additional load. The critical decisions at existing assets match those made in the Preferred Portfolio: F.B. Culley 2 storage, A.B. Brown conversion, and maintaining the F.B. Culley 3 interconnection. This consistency between the two preferred pathways highlights the flexibility in the plan.

It provides a number of benefits to CEI South customers and other stakeholders, beyond what is seen on the balance scorecard, including that it:

- Preserves maximum future flexibility, keeping Southwestern Indiana competitive and able to quickly adapt to support economic development and growth.
- Adds tax base and jobs in our community, helping customers thrive. Both the addition of prospective customers and the additional infrastructure necessary to support it drives economic growth.
- Aligns with current Federal and State goals.
- Utilizes the existing asset at F.B. Culley 3 until future replacement or conversion to natural gas is decided, which will be re-analyzed in subsequent IRPs.
- Adds efficient on-system base load generation through the conversion of A.B. Brown 5 and 6 to a CCGT, which promotes system reliability and provides competitively priced energy that is projected to be consistently lower than market prices.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry and includes a multi-year build out of resources on several sites,

maintaining the option to replace Culley 3 in the future when appropriate, based on continual evaluation of changing technology and conditions.

- Maintains tax base in Warrick County, which is particularly important to the local school system in that county.
- Allows for continued use of existing plant assets, helping to avoid future potential stranded assets.
- Continues CEI South's energy efficiency programs with near-term energy savings of 1.18% of eligible sales over the next 6 years, and further long-term energy savings opportunities of 1.17% of eligible sales identified over the remaining 14 years of the 20-year period. CEI South is committed to energy efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Continues existing demand response programs, including the DLC Residential AC Switch Program, Residential Bring Your Own Thermostat ("BYOT", also known as the Thermostat Load Control Rider), and the approved Aggregation Demand Response Program launched in September 2025. The portfolio also continues implementation of Residential CPP Time-of-Use rates; the pilot is expected to begin in Q2 2026. In addition, a new Commercial Bring Your Own Thermostat program will be introduced, operating consistently with the existing residential thermostat program.

At this time, no contract to secure a large load has been executed. CEI South will continue ongoing conversations with prospective customers. This large load analysis will continue to evolve as the company continues to evaluate possible load additions, timelines, and costs necessary to serve. While the alternate preferred portfolio provides great insight into a possible path, the resource mix used to serve the potential customer will be heavily influenced by the balance of the customer's needs and priorities. As discussions continue, CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations advance to negotiations or contracting.

Short Term Action Plan

Chapter 7

7.1. Differences Between the Last Short Term Action Plan from What Transpired

Since the last IRP was filed there have been significant challenges in moving forward with key pieces of the last two IRP Preferred Portfolios. First, several solar projects have been terminated due to market dynamics that caused prices to escalate beyond what the Commission approved and beyond where CEI South believed to be affordable for its customers. As such, the Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025, due to cost increases beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had similar upward pricing pressure; after years of negotiation and a re-evaluation of this project in this IRP, CEI South opted to walk away from this project in an effort to keep customer rates as affordable as possible in the near to mid-term.

CEI South conducts the IRP process every three years and each IRP, necessarily builds on the previous IRP and the generation resource investments that have come before. The Preferred Portfolio in CEI South's previous 2022/2023 IRP concluded that a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with DSM, wind, and solar resources. CEI South began implementing this 2022/2023 IRP by filing two cases seeking approval for (1) signed purchase power agreements ("PPA") for two wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project. (2) CEI South sought and received approval for the 2025-2027 DSM Plan. Each of these filings was consistent with the 2022/2023 IRP, and as noted below, this IRP affirms the direction taken by CEI South. These remaining renewable resources from prior IRPs still qualify for Federal incentives, which dramatically lowered the cost of these renewable resources relative to what could be acquired in the future, post elimination of IRA tax incentives for wind and solar resources.

In preparation for retirement, CEI South submitted an Attachment Y to MISO to suspend operations of its smallest, least efficient coal unit, F.B. Culley 2. This unit is slated for retirement at the end of 2025, consistent with the last IRP. A key decision in this IRP is to determine how to replace this unit and whether or not to preserve the existing interconnection to the grid. CEI South will have approximately three years to replace the unit, preserving the interconnection. Options that were available, meeting limited space requirements, were small gas units (reciprocal engines or aero derivative) or battery storage.

7.1.1. Culley 3 Conversion

In the last IRP CEI South selected a Preferred Portfolio that converted F.B. Culley 3, a 270 MW coal plant, to natural gas by 2027. Given the inputs and likely potential future at that time, this was a competitive option. As CEI South observed increased change and uncertainty, it decided to pause on the conversion and not seek a certificate of convenience and necessity to gain approval from the IURC. CEI South chose to re-evaluate this option within this IRP. While coal to gas conversion may make sense in the future, it does not today. As discussed in this IRP, the conversion with renewables today is projected to be 14% higher cost than the Preferred Portfolio. CEI South will reevaluate this option in its next IRP.

7.1.2. Posey Solar and Two New CTs

CEI South brought Posey solar (191 MW) and A.B. Brown unit 6 (230 MW) online at the end of May 2025. A.B. Brown unit 5 (230 MW) came online at the end of August, consistent with expectations from the last IRP. All three new units have been performing well since coming online.

7.1.3. DSM

The 2022/2023 IRP did support continued energy efficiency programs designed to save 1.1% of eligible retail sales. CEI South proposed the 2025-2027 Electric DSM Plan (*Technical Appendix Attachment 3.4*) to obtain approval of programs to achieve this level of savings. The Commission approved this plan on March 26, 2025 in Cause No. 46100. Consistent with the 2022/2023 IRP, the framework for the 2025-2027 filed plan was modeled at a savings level of 1.1% of retail sales adjusted for an opt-out rate of 77% eligible load. Additionally, CEI South updated all of its DR tariffs in Cause No. 45990 to provide more consistency, to open them to a wider range of potential customers, and to align with changes in the MISO Business Practices Manual. Additionally, CEI South received approval in the same cause to offer DR aggregation to C&I customers and have signed a contract to begin working with Enel X as the program implementer. Enel X began outreach and enrollment in October and has signed a letter of authorization with twenty customers to begin sharing meter data to explore energy plans and contracts and has five customers with a signed contract.

7.2. Discussion Of Plans For The Next 3 Years

7.2.1. Procurement of Resources

CEI South has continued to diversify its portfolio of resources with two wind projects identified in its last IRP. On November 5, 2005 the Commission approved the Salt Creek Wind Project purchase power agreements (“PPA”). That, along with the Galesburg Wind

PPA is expected to come online in 2026, bringing a total of 317 MW of additional clean renewable wind energy to serve our customers. Additionally, the Wheatland solar PPA project is expected to come online at the end of Q1 2026.

7.2.2. RFPs and Continued Evaluation of F.B. Culley 2 interconnection

At the end of 2025 CEI South will place F.B. Culley 2 in suspension with the plans of transferring the interconnection to a 90 MW battery storage unit before the end of 2028. This will require CEI South to replace its existing Attachment Y with an Attachment X. CEI South plans to utilize the results of RFPs for capacity and for a new RFP for battery storage unit to further evaluate the economics and reliability attributes of this option relative to purchasing required capacity to maintain reliability. Pending the results of this analysis, CEI South may file a CPCN for a 90 MW battery storage unit at F.B. Culley and have a COD by the end of 2028.

7.2.3. DSM

CEI South filed for and received approval on March 26, 2025 for a 3-year DSM Plan for 2025-2027 with energy efficiency savings guided by the 2022/2023 IRP process. The CEI South Oversight Board, including the OUCC, CAC and CEI South, will oversee the implementation of energy efficiency programs. CEI South will file a 3-year DSM Plan for 2028-2030 the first half of 2027 consistent with energy efficiency savings guided by the Preferred Portfolio in the 2025 IRP. The Aggregation Demand Response Rider is a 5-year contract and will be ongoing until the end of the contract in 2030, at which time the program will be re-evaluated.

7.2.4. Other Innovative Rate Design

CEI South has been actively working to develop a TOU CPP Pilot program that is set to begin in Q2 2026. CEI South utilized its continuous improvement and project management teams to work collaboratively with business units to build out the necessary infrastructure to support the pilot, including development of a new system to execute CPP events and help facilitate customer enrollment. CEI South will work through the pilot over the next one to two years in the hopes of expansion, if the pilot is successful. Results of the pilot will be included in the next IRP; if the pilot is successful and the next IRP continues to indicate that the program is beneficial for customers, CEI South will propose to expand the rate to the majority of its residential customers in the next general rate case following the next IRP.

7.2.5. Demand Response

CEI South will continue to work with its demand response aggregator in the hopes of attracting C&I customers to participate. This IRP included an indicative amount of industrial DR for this program.

7.2.6. Ability to Finance the Preferred Portfolio

The Company expects to have sufficient funds to finance the Preferred Portfolio through a combination of internally generated cash flow from operations, external capital markets activity, and capital contributions from its parent company. CEI South's secured debt ratings are currently A1/A with a stable outlook from Moody's Investors Services and S&P Global Ratings, respectively.

7.2.7. Continuous Improvement

CEI South works hard on continuous improvement and will take the feedback that we receive on this IRP into consideration as we develop the next IRP. We appreciate formal or informal comments from active stakeholders and what is received through the Director's report. They will be used as the basis for continuous improvement going forward.

7.3. Schedule

Below is a general timeline for implementation of the Preferred Resource Portfolio, subject to change.

Figure 7-1 - Implementation Schedule

Timing	Activity Type	Actions
Q3 2025	Demand Response	Initiation of DR aggregator program
Q1 2026	Generation Transition	Salt Creek Wind (170 MW PPA) online Wheatland Solar (150 MW PPA) online
Q1 – Q2 2026	Storage RFP	Conduct an RFP for storage at F.B. Culley 2. If determined to be affordable, submit a Certificate of Public Convenience and Necessity (CPCN) for 90 MW battery storage in Q3.
Q1 – Q2 2026	Demand Response	Planned implementation of DR aggregator program
Q2 2026	Rate Design	Planned implementation of TOU CPP Pilot program
Q2 – Q3 2026	Generation Transition	Galesburg Wind (147 MW PPA) online
Q1 – Q2 2027	DSM Plan	File a 3-year DSM plan for 2028 through 2030 informed by the 2025 IRP in the first half of 2027
Ongoing	Large Load Addition	Continue to work through due diligence for possible large load addition

Technical Appendix

Chapter 8

8.1. Load Forecast Appendix

8.1.1. Forecast Inputs

8.1.1.1. Energy Data

Historical CEI South sales and revenues data were obtained through the billing system. The billing system contains detailed customer information including rate, service, North American Industrial Classification System ("NAICS") codes (if applicable), usage and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

8.1.1.2. Economic and Demographic Data

Economic and demographic data was obtained from S&P Global (formerly IHS Markit) for the state of Indiana and the Evansville Metropolitan Statistical Area ("MSA"). S&P Global is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to CEI South contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS) and industrial (large) sales.

8.1.1.3. Weather Data

Historical and normal Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") are derived from daily temperature data for the Evansville airport. HDDs are defined as the number of degrees below a base temperature for a given day. CDDs are defined as the number of degrees above a base temperature for a given day. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

In reviewing historical weather data, Itron found a statistically significant positive, but slow, increase in average temperature. This translated into fewer HDD and more CDD over time. Itron's analysis showed HDD are decreasing 0.4% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.4% over the forecast period while CDD increased 0.5% per year through 2045. Figure 8-1 and Figure 8-2 show historical and forecasted monthly HDD and CDD.

Figure 8-1 - Heating Degree Days

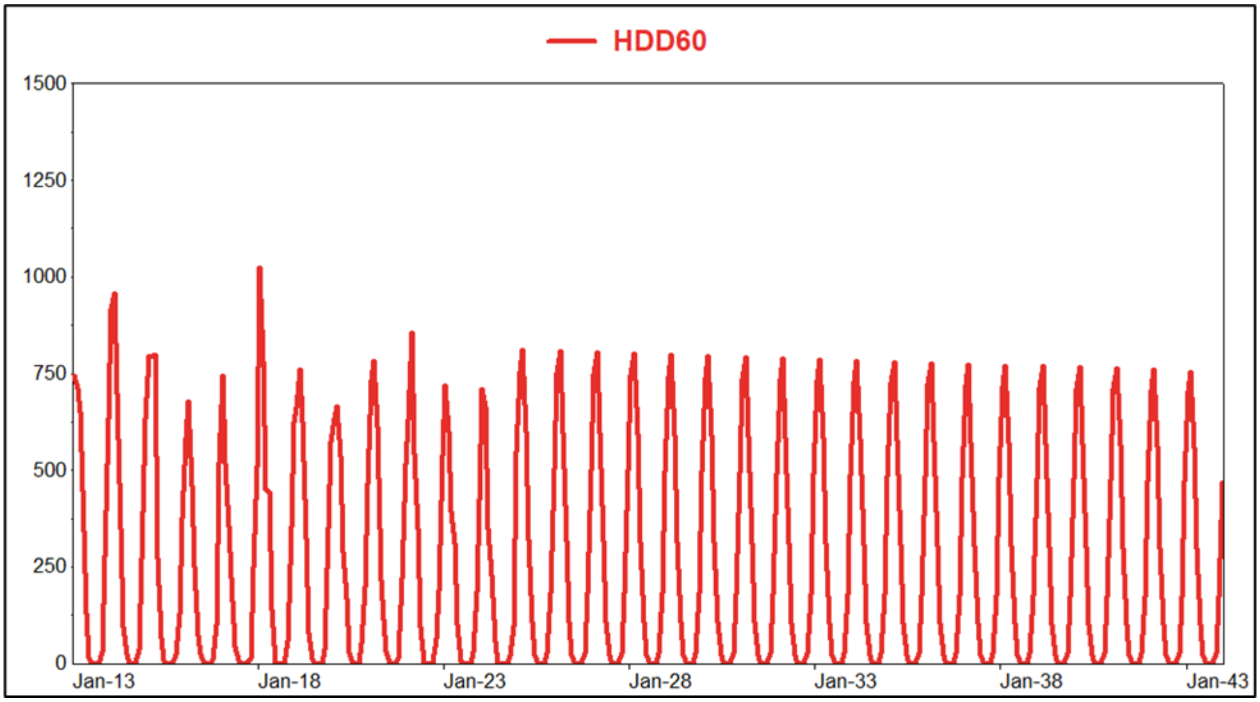
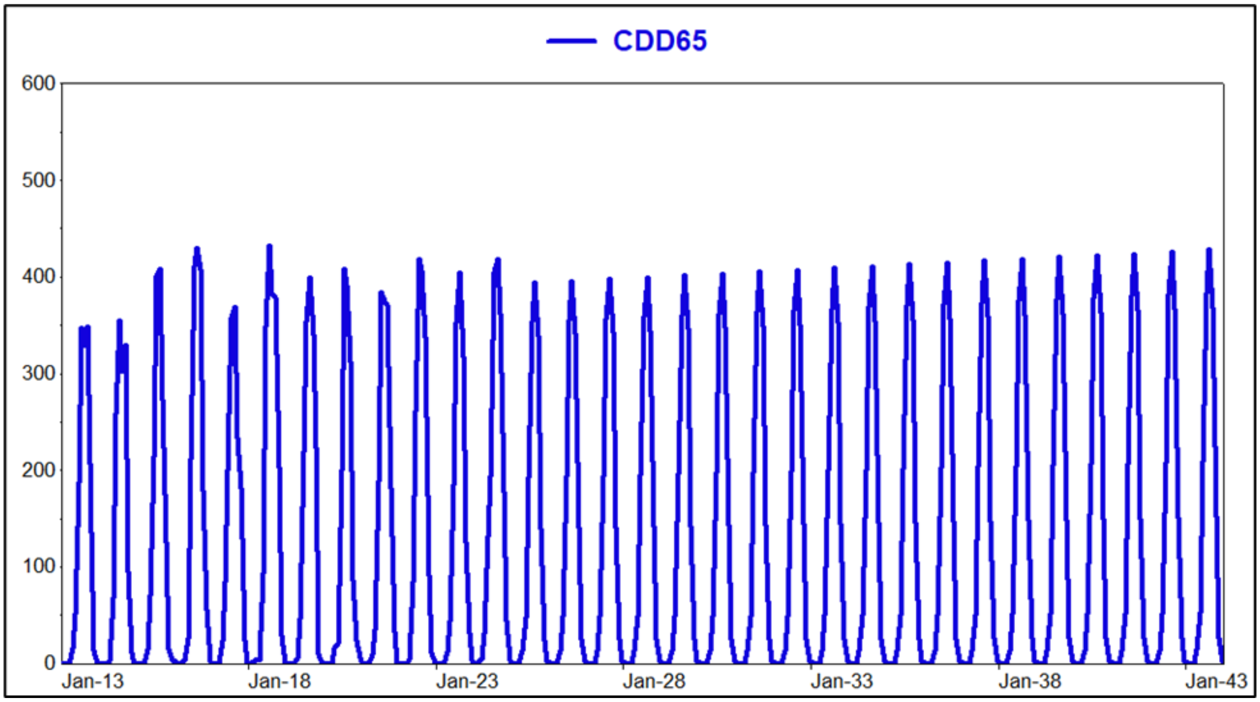


Figure 8-2 - Cooling Degree Days



8.1.1.4. Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional EIA historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. CEI South conducted an Electric Baseline survey in the third quarter of 2016 of CEI South's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. To increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of CEI South's actual territory.

8.1.1.5. Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE modeling framework. In addition to annually updating efficiency and saturation projections with the latest estimates from the EIA the framework has evolved to include utility specific DSM program activity data. The inclusion of a utility specific DSM variable in the modeling specification greatly improves model fit and enables the model to produce a baseline forecast excluding the impact of future DSM program activity. Additionally, Itron built a framework for the inclusion and use of trended normal weather where historical weather patterns show this to be appropriate. The CEI South forecast now considers emerging technologies: customer distributed generation and electric vehicles. Customer owned PV adoption is modeled as a function of simple payback. The model explains historic adoption well and provides a framework that considers projected PV installation costs, electric prices and incentives. The adoption of electric vehicles is based on the EIA's forecast of vehicle stock. The EIA's has robust transportation model that includes a vehicle manufacturer component and a consumer choice component to estimate the mix of vehicles by powertrain type: gasoline, diesel, electric, plug-in hybrid electric, etc. The model accounts for projected fuel prices, electric prices, the decline in battery costs and federal incentives for electric vehicles.

Additionally, CEI South continually stays up to date with load forecasting topics in a variety of ways. First, CEI South is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Forecasters typically attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. CEI South forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, CEI South discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. CEI

South compares CEI South model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

8.1.2. Overview of Past Forecasts

The following tables outline the performance of CEI South's energy and demand forecasts over the last several IRPs by comparing Weather Normalized ("WN") sales and demand figures to IRP forecasts from 2015-2024.

Weather-normalization is performed each month in order to analyze the variance from the forecast without the impact of weather. This is done by combining customer count, meter read schedule, billing month sales and daily temperature with estimates of the impact of changes in usage to variations of temperature. Underlying the estimates are average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data. Actual weather data from NOAA is used to generate daily use per customer estimates for the revenue classes. The results are used to predict daily use estimates and are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures.

The following tables show the WN[41] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

[41] Note that large sales are not weather normalized.

Figure 8-3- Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (MW)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,155				1,113	-3.8%			
2016	1,156				1,087	-6.3%			
2017	1,113	1,082			1,038	-7.2%	-4.3%		
2018	1,109	1,086			1,006	-10.2%	-7.9%		
2019	1,106	1,085			1,039	-6.4%	-4.5%		
2020	1,106	1,088	1,106		990	-11.8%	-9.9%	-11.7%	
2021	1,106	1,084	1,107		998	-10.8%	-8.5%	-10.8%	
2022	1,107	1,083	1,129		1,013	-9.2%	-6.9%	-11.4%	
2023	1,107	1,083	1,168	1,010	1,052	-5.2%	-2.9%	-11.0%	4.0%
2024	1,107	1,084	1,172	1,087	1,070	-3.5%	-1.3%	-9.5%	-1.6%
Mean Absolute Error						7.4%	5.8%	10.9%	1.2%

Figure 8-4- Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	5,914				5,773	-2.4%			
2016	5,936				5,725	-3.7%			
2017	5,514	5,257			5,073	-8.7%	-3.6%		
2018	5,503	5,290			5,139	-7.1%	-2.9%		
2019	5,494	5,294			4,965	-10.6%	-6.6%		
2020	5,497	5,319	5,400		4,788	-14.8%	-11.1%	-12.8%	
2021	5,492	5,302	5,405		4,923	-11.6%	-7.7%	-9.8%	
2022	5,494	5,303	5,527		4,834	-13.7%	-9.7%	-14.3%	
2023	5,494	5,308	5,755	4,725	4,793	-14.6%	-10.7%	-20.1%	1.4%
2024	5,496	5,320	5,784	5,164	5,096	-7.9%	-4.4%	-13.5%	-1.3%
Mean Absolute Error						9.5%	7.1%	14.1%	0.0%

Figure 8-5- Residential Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,404				1,444	2.8%			
2016	1,394				1,416	1.5%			
2017	1,383	1,407			1,398	1.1%	-0.6%		
2018	1,377	1,395			1,375	-0.2%	-1.5%		
2019	1,374	1,384			1,372	-0.1%	-0.9%		
2020	1,373	1,375	1,386		1,408	2.5%	2.3%	1.5%	
2021	1,370	1,366	1,376		1,417	3.3%	3.6%	2.9%	
2022	1,373	1,362	1,378		1,378	0.4%	1.2%	0.0%	
2023	1,377	1,359	1,382	1,433	1,402	1.8%	3.1%	1.4%	-2.2%
2024	1,383	1,359	1,390	1,453	1,446	4.3%	6.1%	3.9%	-0.5%
Mean Absolute Error						1.7%	1.7%	1.9%	1.4%

Figure 8-6- Commercial (GS) Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,304				1,321	1.3%			
2016	1,320				1,281	-3.0%			
2017	1,315	1,315			1,278	-2.9%	-2.9%		
2018	1,311	1,324			1,235	-6.1%	-7.2%		
2019	1,308	1,326			1,184	-10.5%	-12.0%		
2020	1,311	1,325	1,280		1,117	-17.4%	-18.7%	-14.7%	
2021	1,310	1,321	1,284		1,165	-12.4%	-13.4%	-10.1%	
2022	1,313	1,322	1,290		1,156	-13.5%	-14.3%	-11.6%	
2023	1,315	1,324	1,294	1,186	1,124	-17.0%	-17.8%	-15.1%	-5.5%
2024	1,320	1,330	1,300	1,186	1,179	-12.0%	-12.9%	-10.3%	-0.6%
Mean Absolute Error						9.4%	12.4%	12.3%	3.1%

Figure 8-7- Industrial (Large) Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	2,916				2,722	-7.1%			
2016	2,932				2,722	-7.7%			
2017	2,546	2,211			2,097	-21.4%	-5.5%		
2018	2,547	2,252			2,182	-16.7%	-3.2%		
2019	2,546	2,270			2,073	-22.8%	-9.5%		
2020	2,549	2,312	2,348		1,971	-29.3%	-17.3%	-19.1%	
2021	2,550	2,317	2,360		2,041	-25.0%	-13.5%	-15.6%	
2022	2,550	2,322	2,464		2,015	-26.5%	-15.2%	-22.2%	
2023	2,549	2,329	2,670	1,793	1,986	-28.4%	-17.3%	-34.5%	9.7%
2024	2,546	2,334	2,682	2,189	2,244	-13.5%	-4.0%	-19.5%	2.5%
Mean Absolute Error						19.8%	10.7%	22.2%	6.1%

8.1.3. Actual and Weather Normalized Energy and Demand Levels

Figure 8-8- Historic Peak Demand

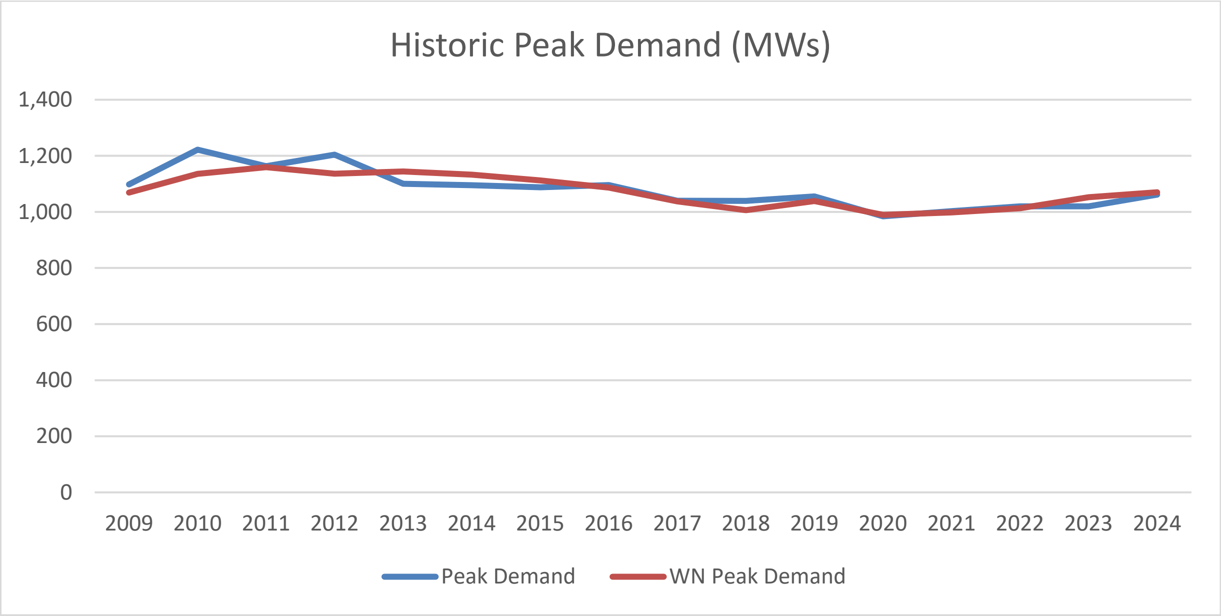
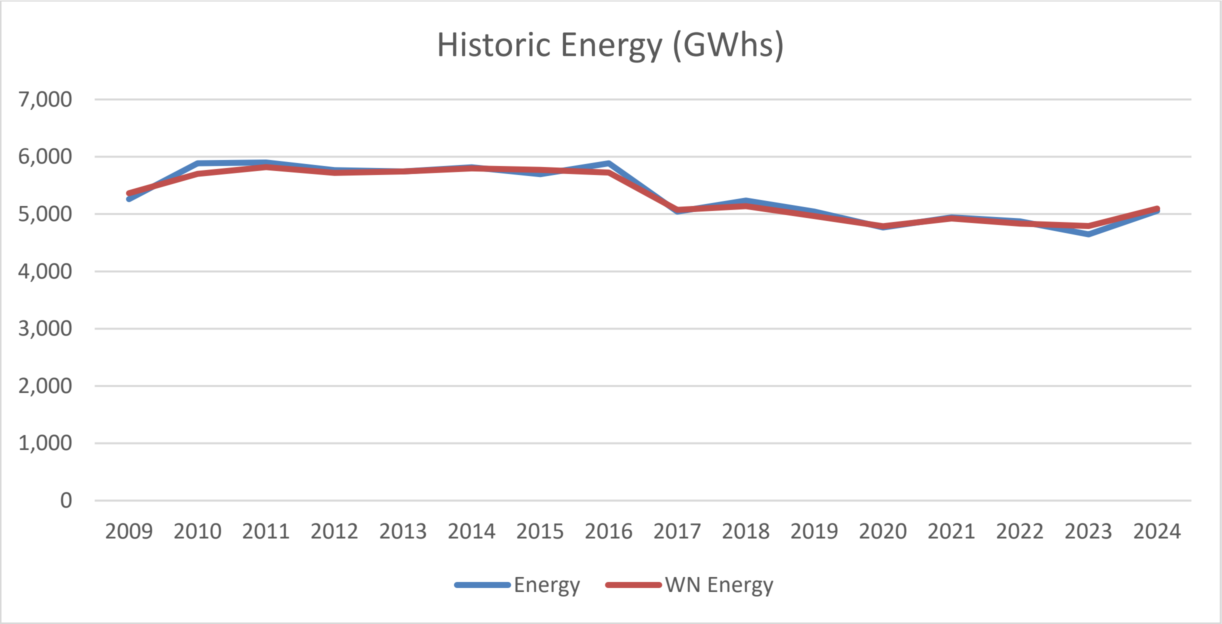


Figure 8-9- Historic Energy



8.1.4. Load Shapes

Figure 8-10- Historic Annual Load Shape

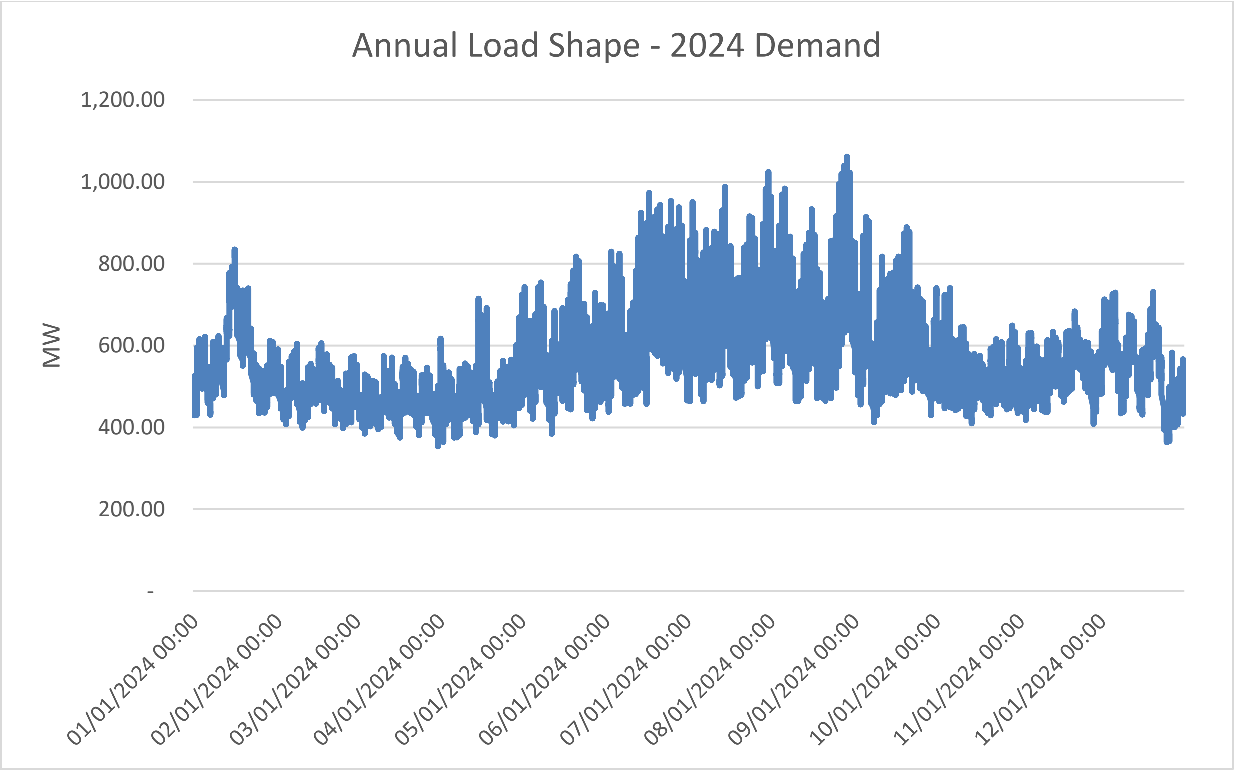


Figure 8-11- Summer Peak Day

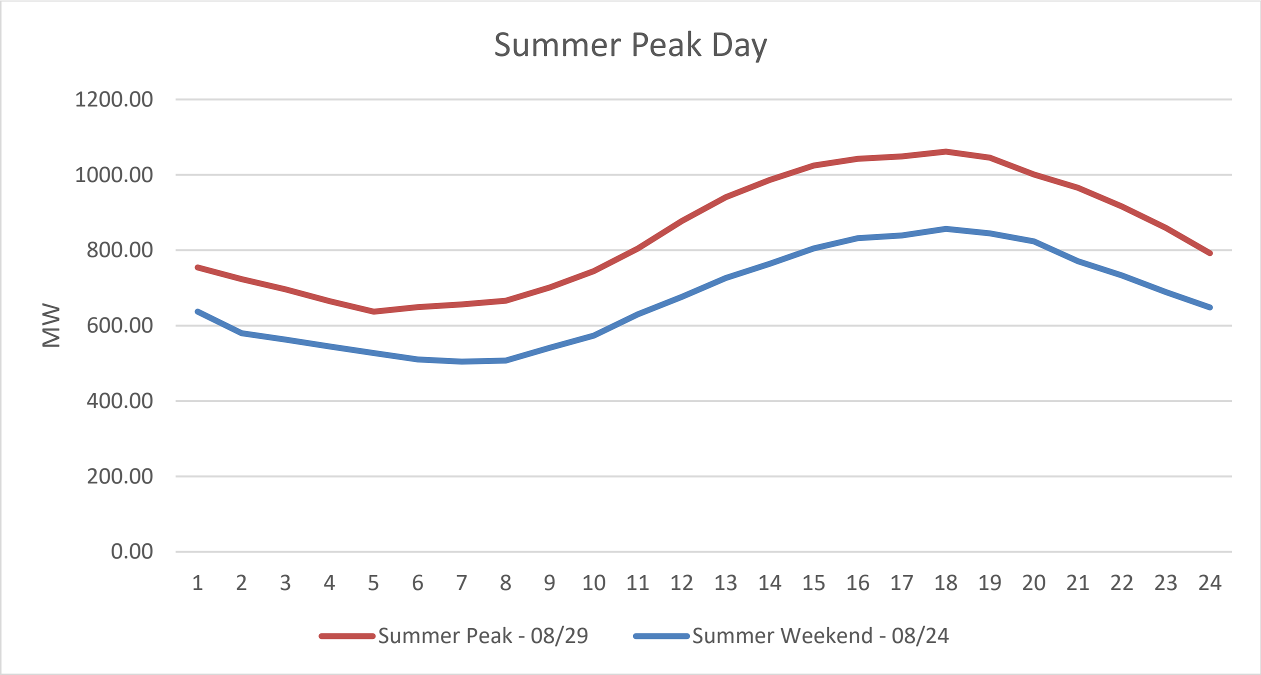


Figure 8-12- Typical Fall Day

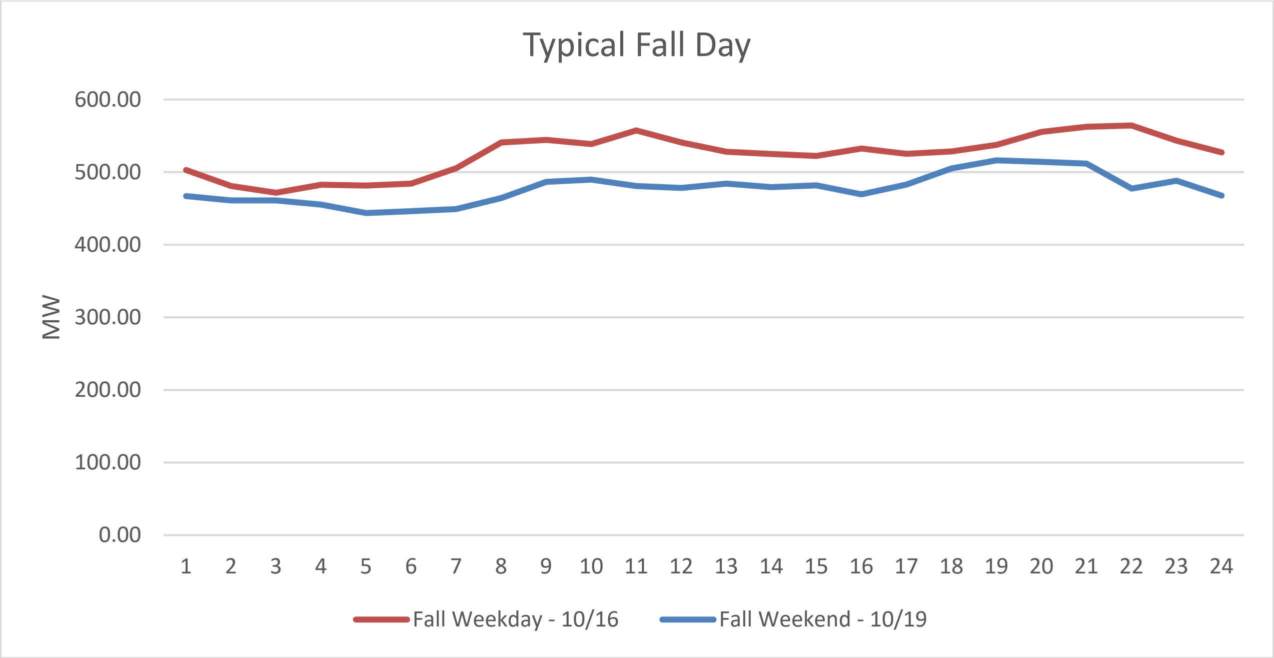


Figure 8-13- Winter Peak Day

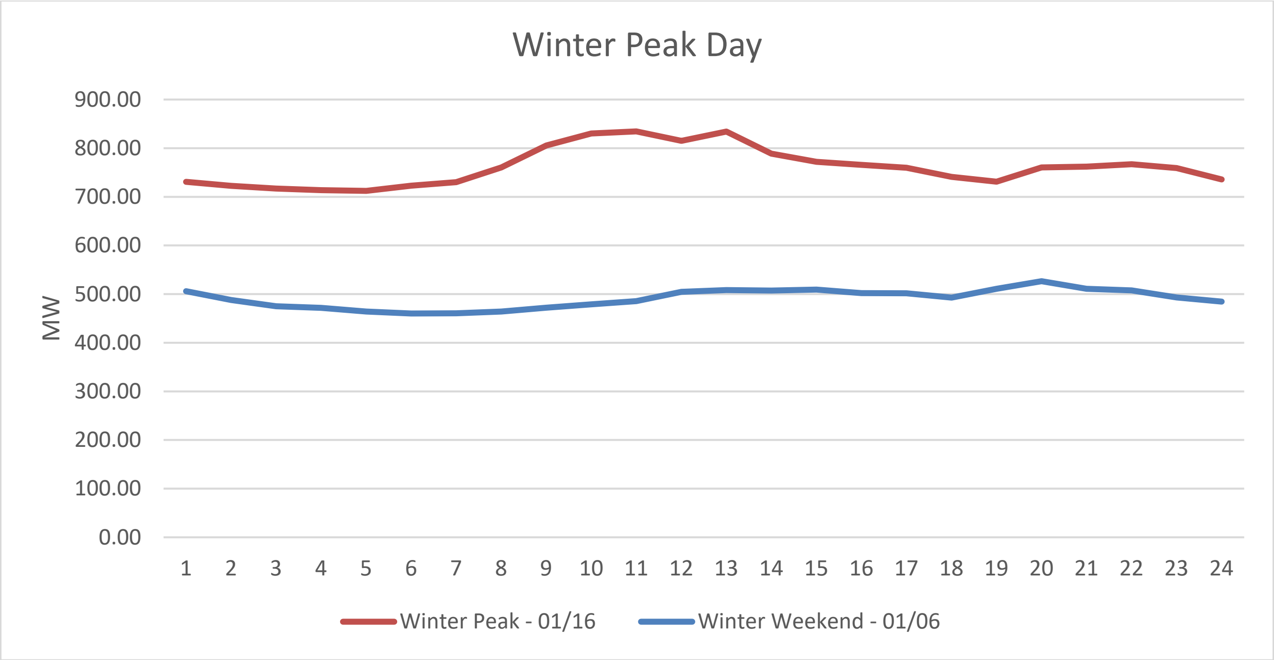


Figure 8-14- Typical Spring Day

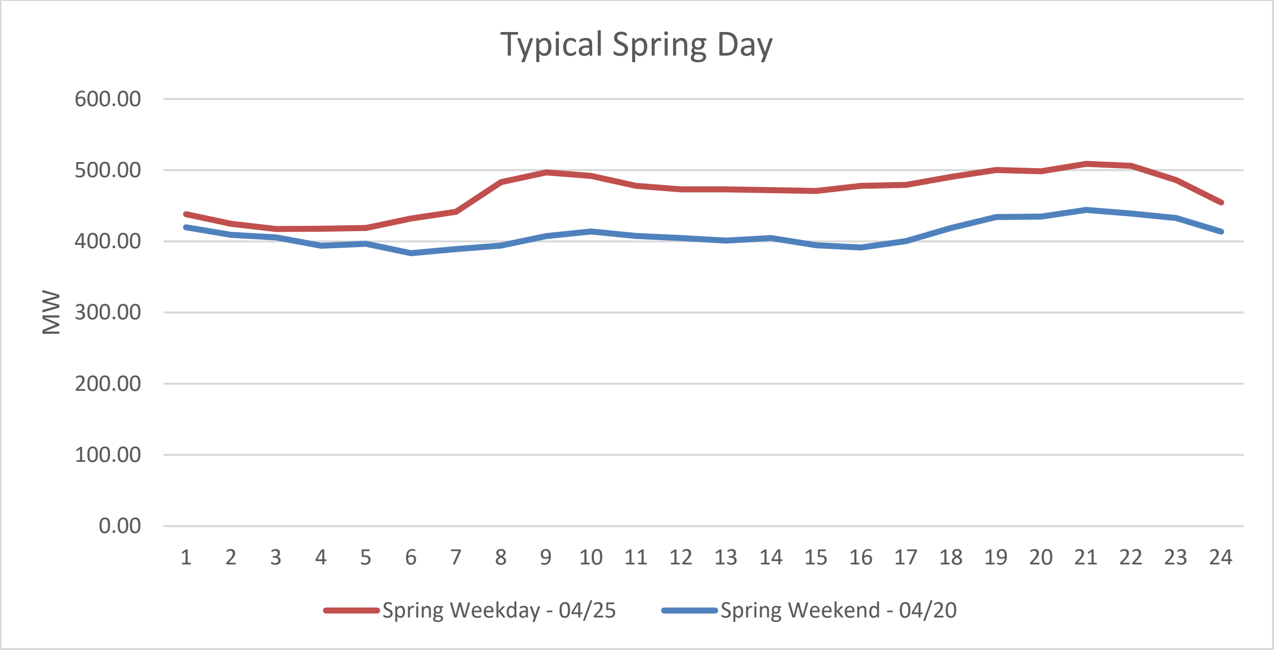


Figure 8-15- January Load

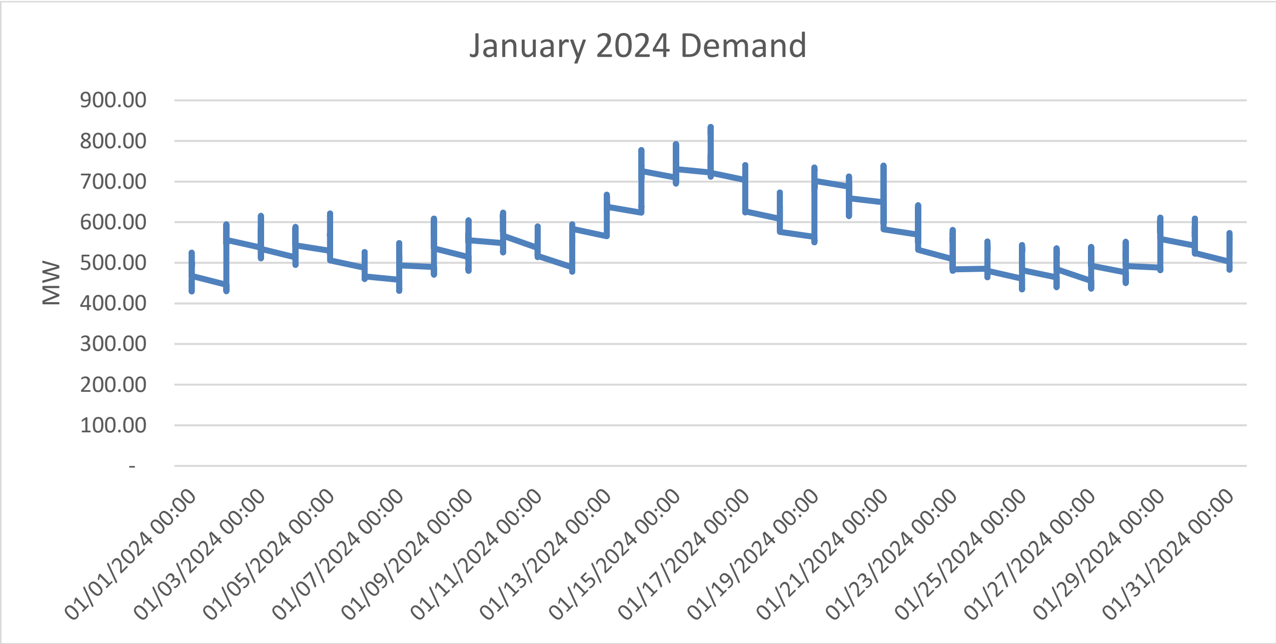


Figure 8-16- February Load

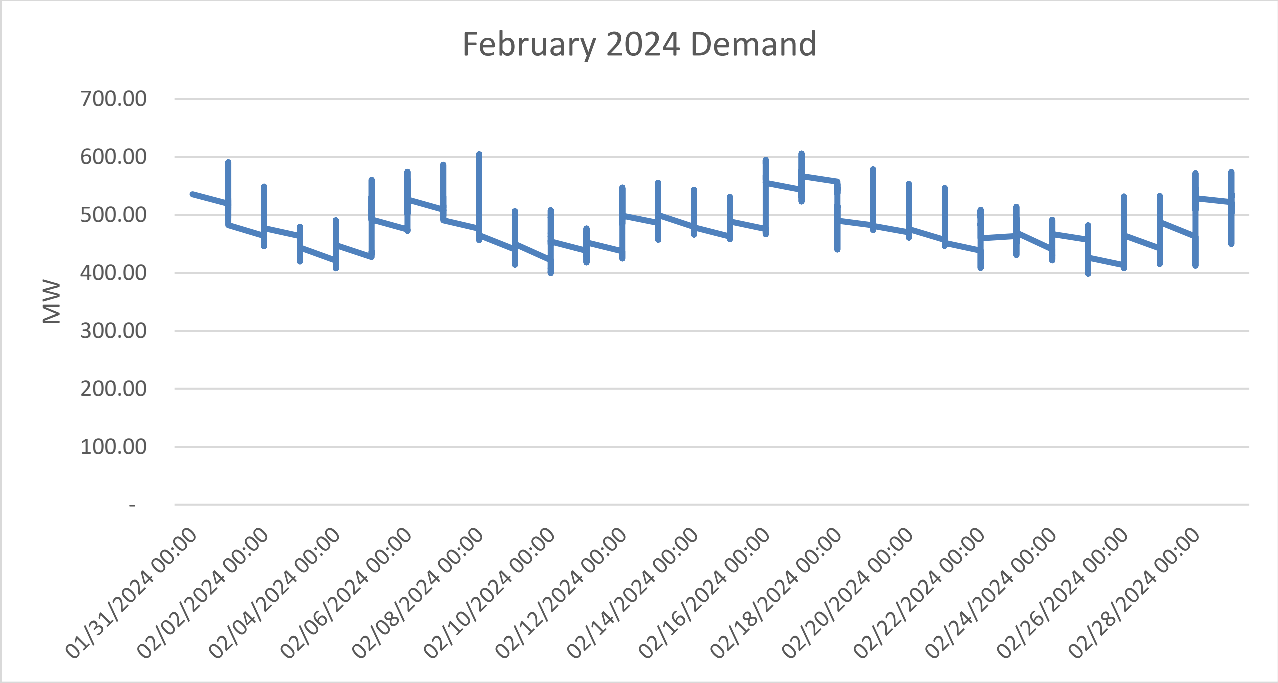


Figure 8-17- March Load

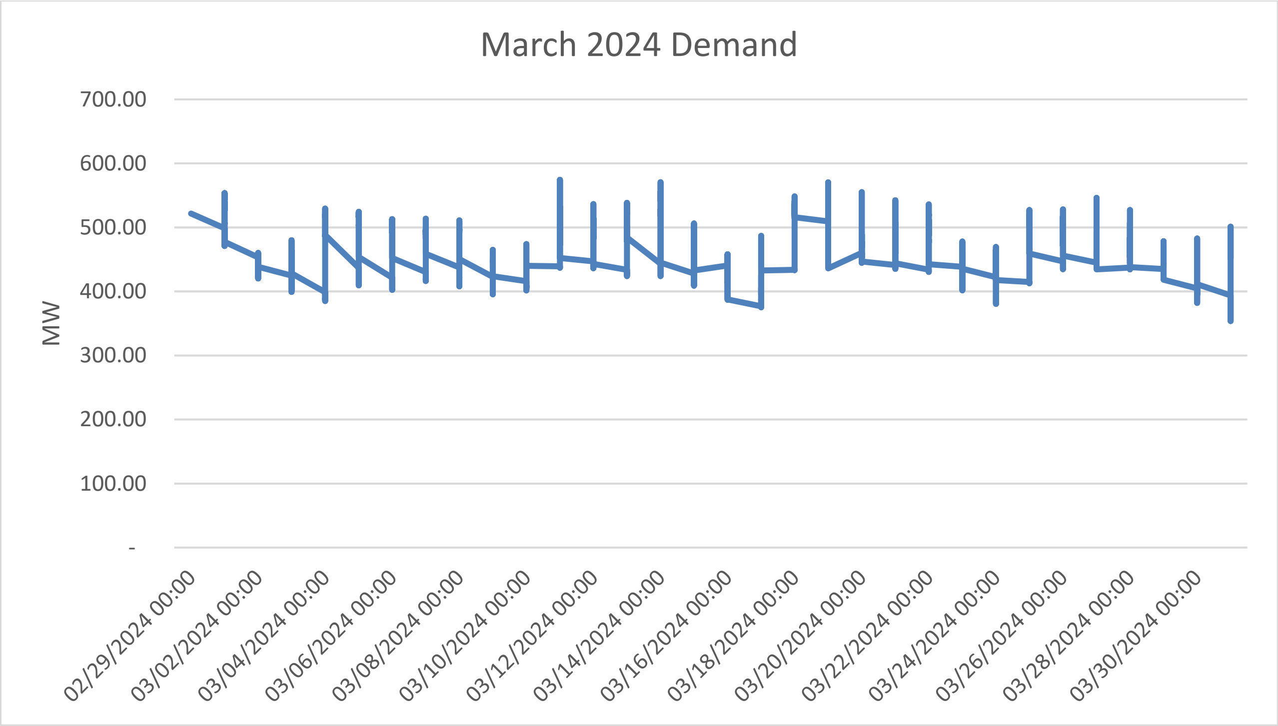


Figure 8-18- April Load

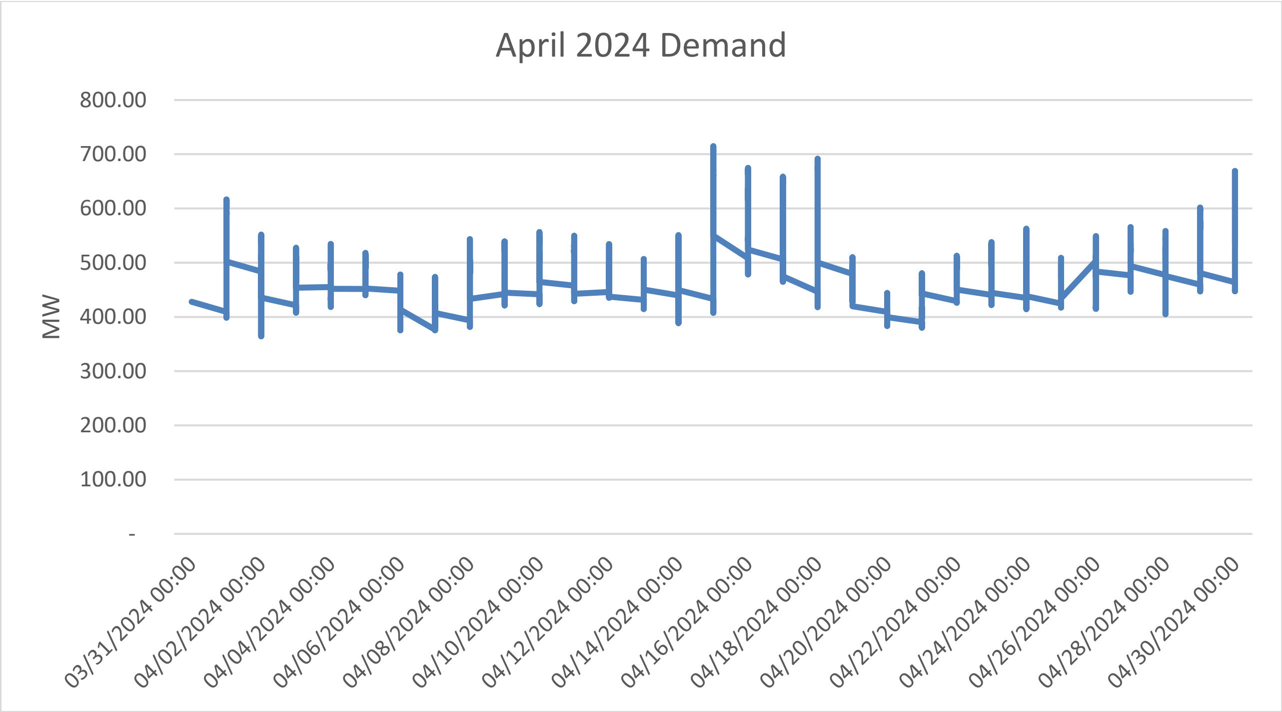


Figure 8-19- May Load

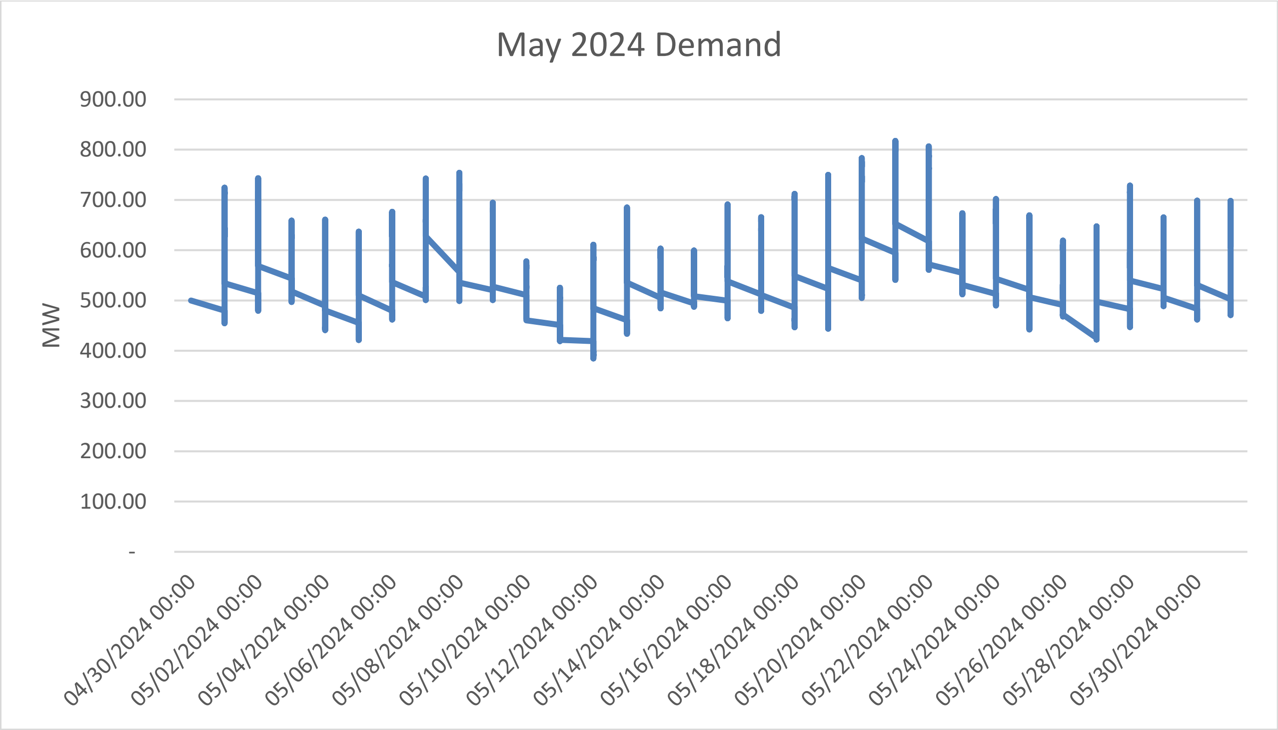


Figure 8-20- June Load

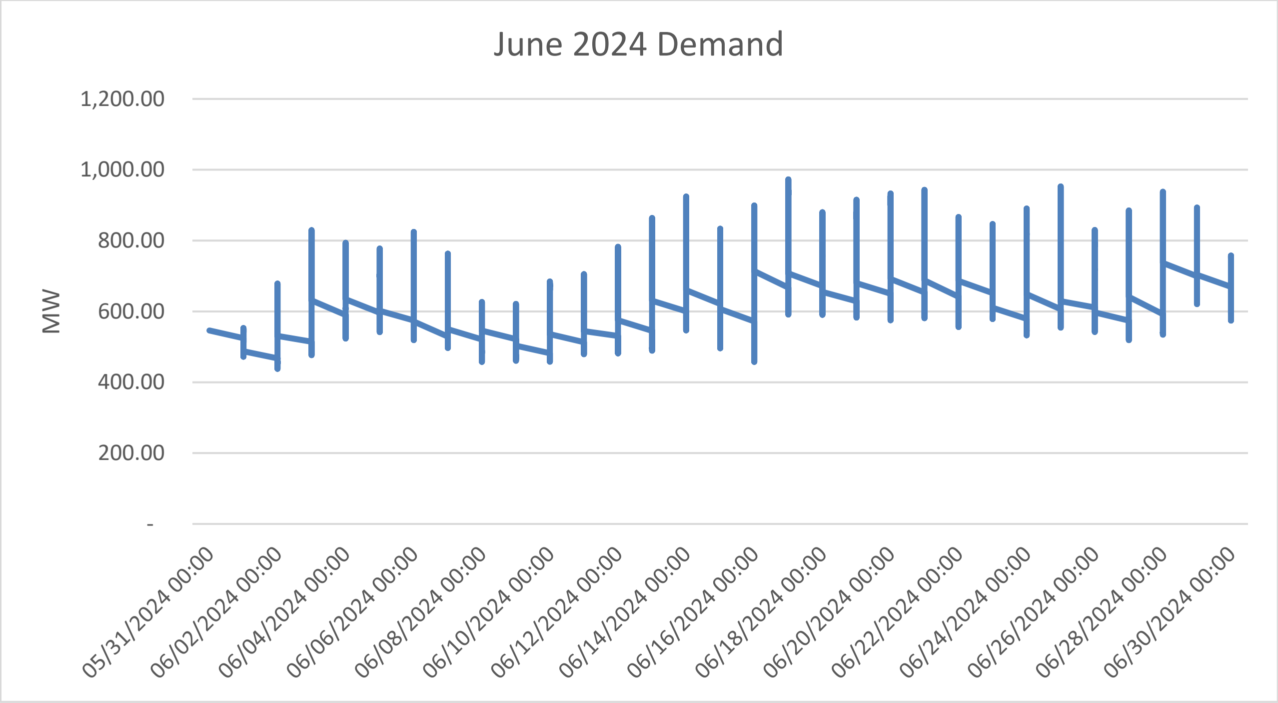


Figure 8-21- July Load

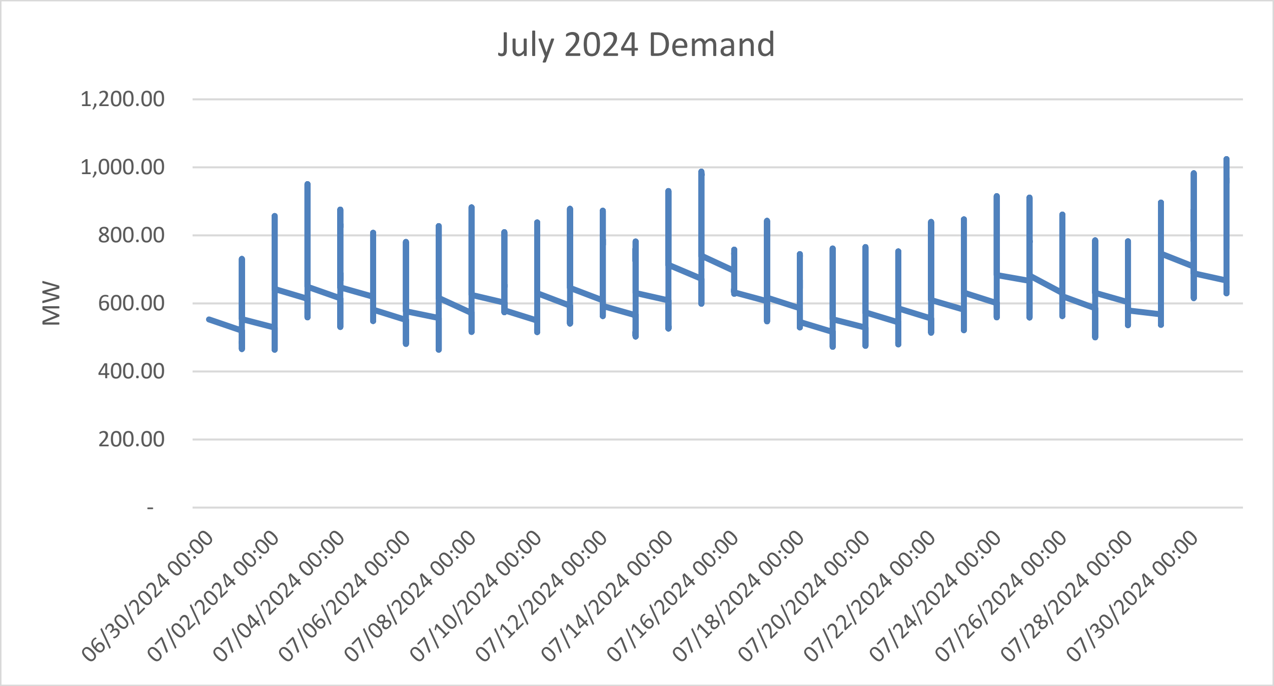


Figure 8-22- August Load

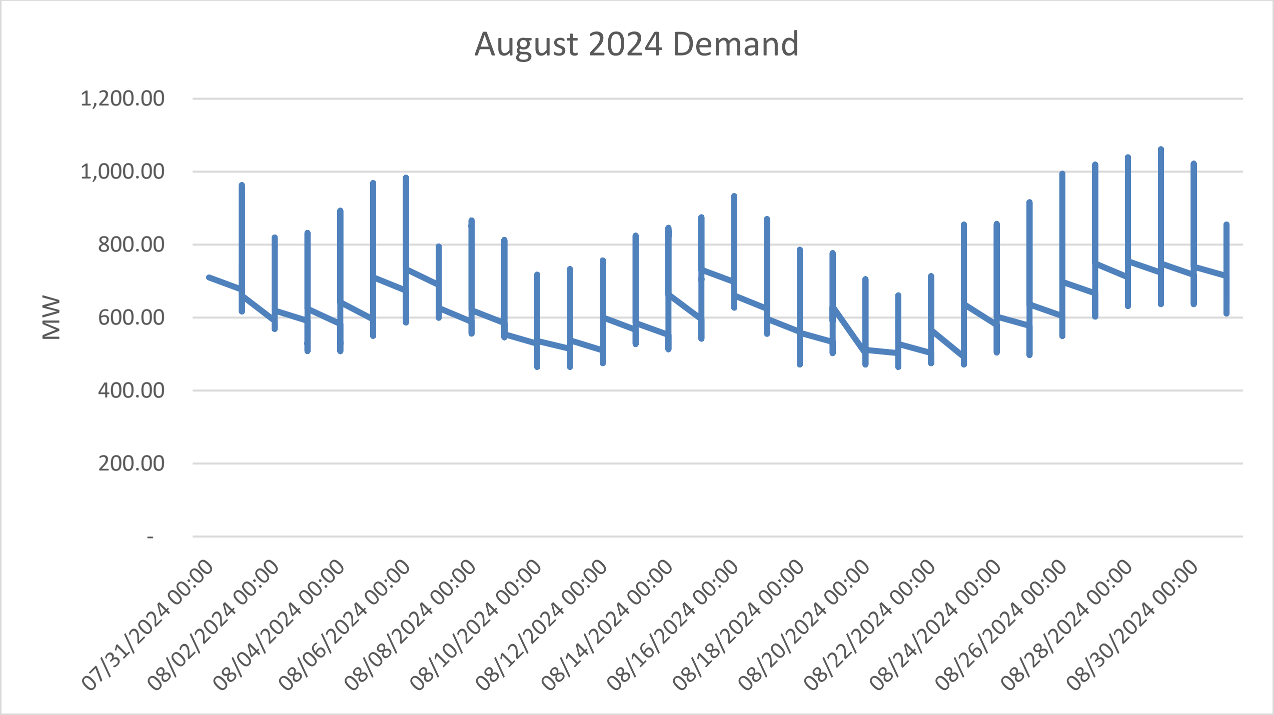


Figure 8-23- September Load

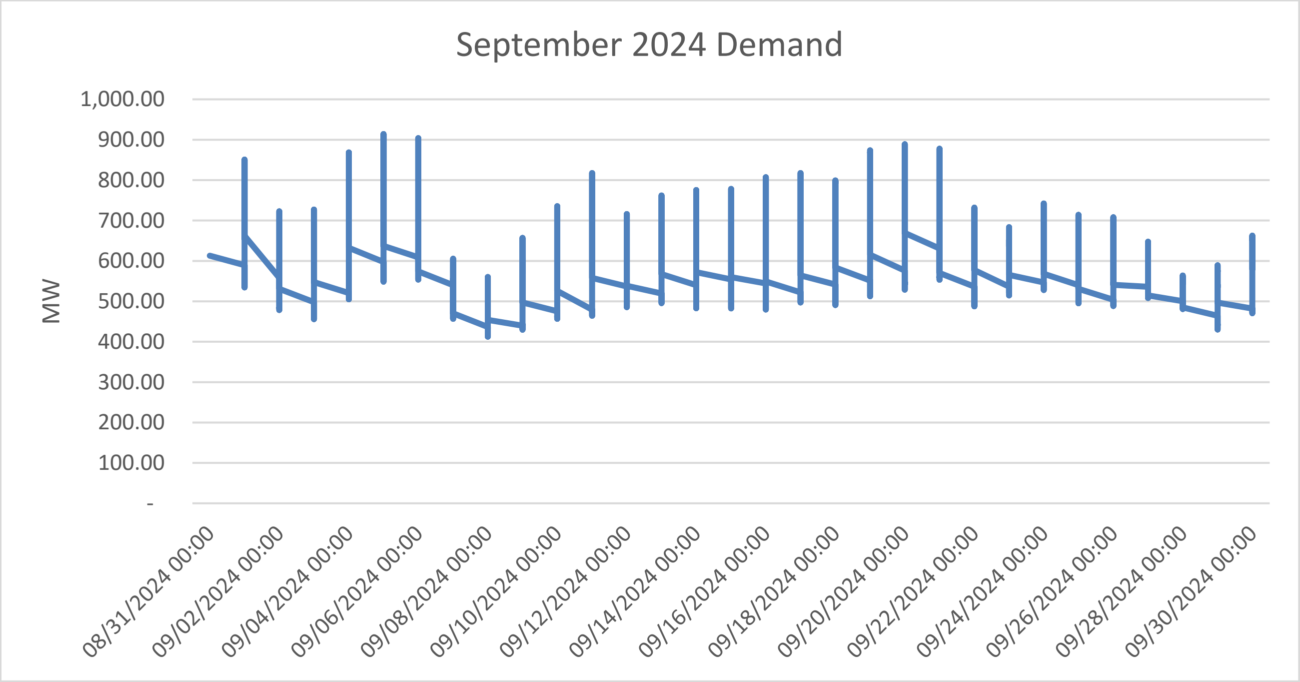


Figure 8-24- October Load

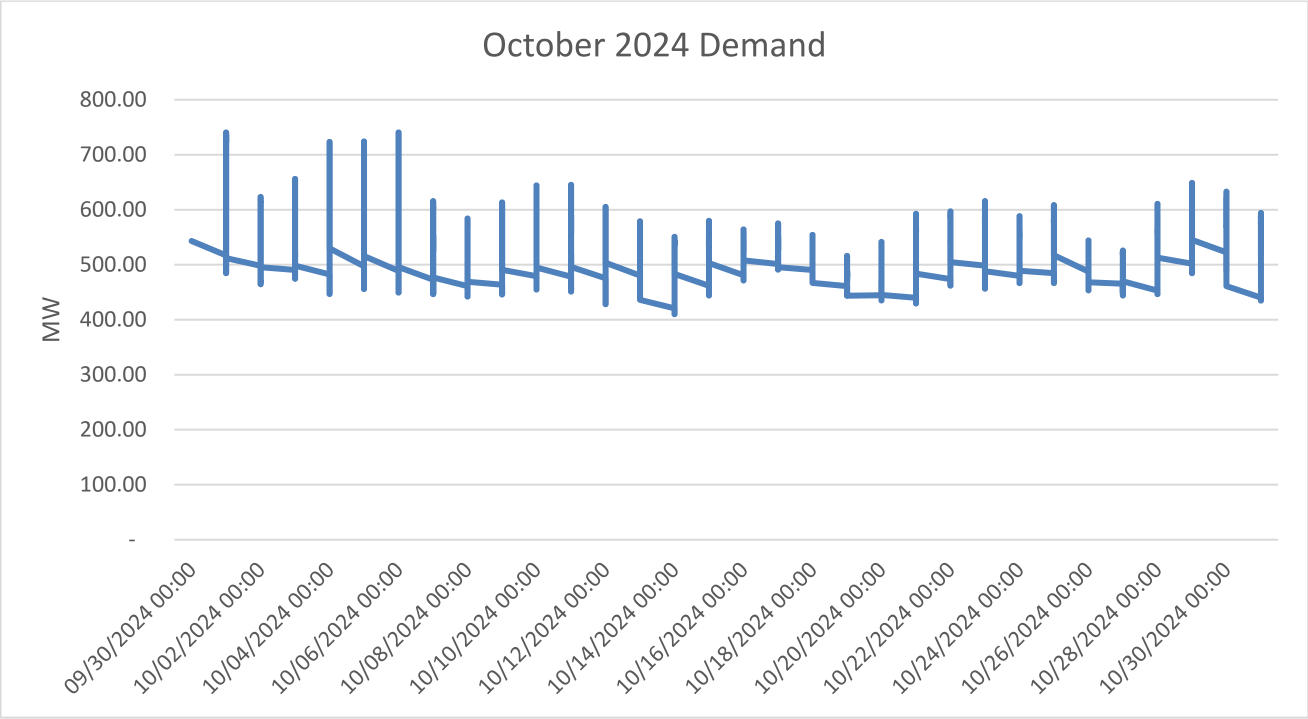


Figure 8-25- November Load

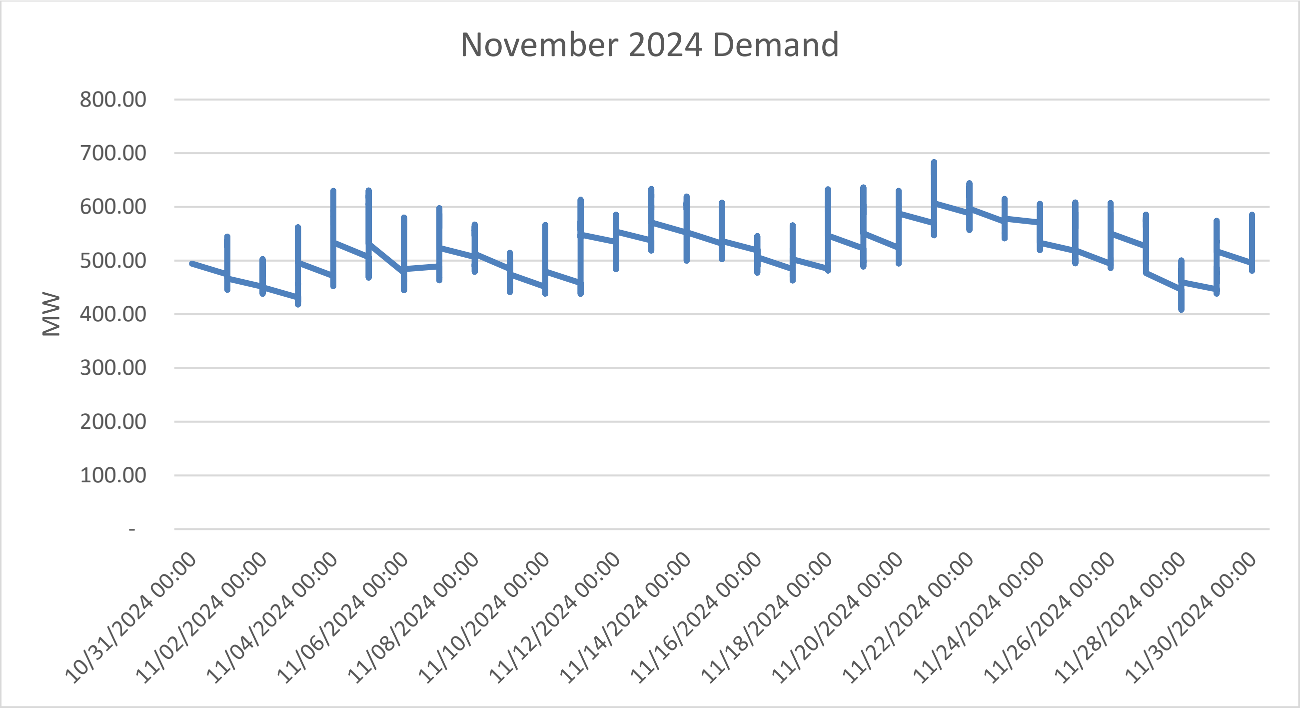
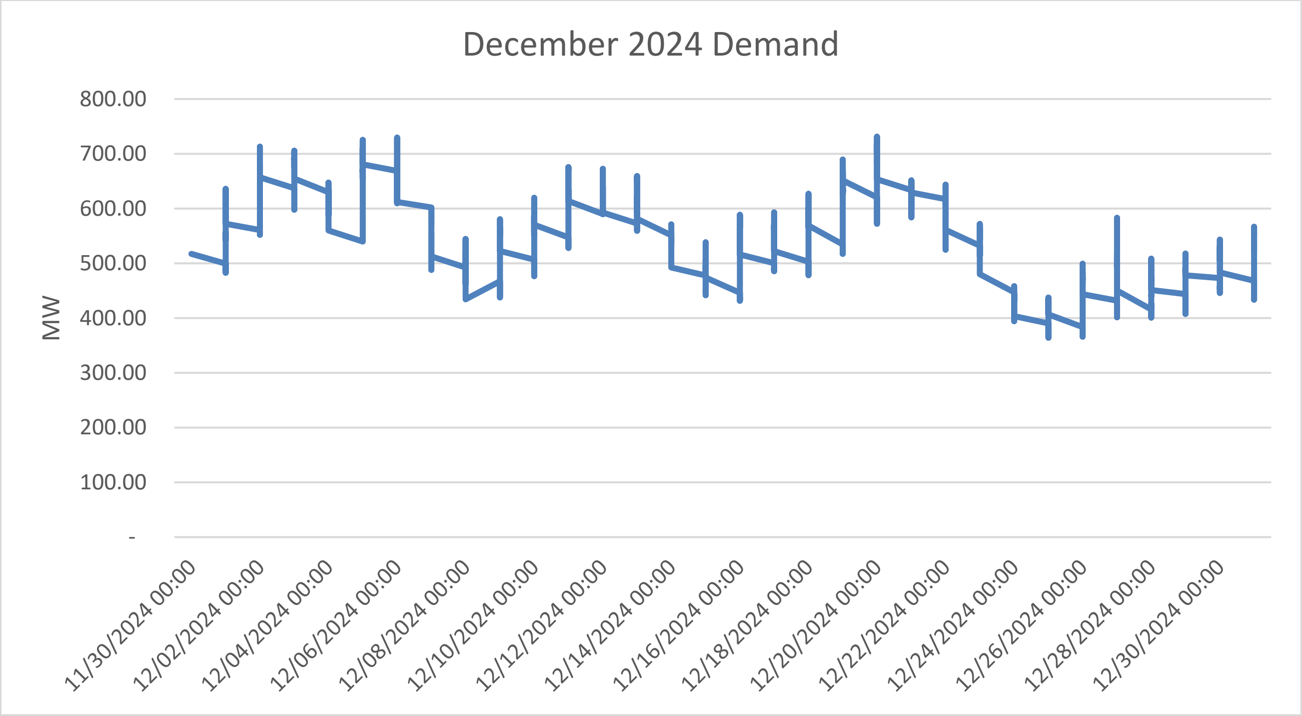


Figure 8-26- December Load



8.1.5. Advanced Metering Infrastructure and Continuous Improvement

CEI South has Advanced Metering Infrastructure (“AMI”). As described previously, the company continues to enhance the system with the use of edge computing applications that provide the company with valuable data to evaluate reliability and resiliency performance, and to find and correct items before they turn into issues that could affect customers. This information can be utilized to enhance forecasting and to perform more effective system planning and improved outage management resulting in better service and communications to customers. CEI South has been actively creating a system to help utilize AMI data for the CPP TOU rate. The pilot that is set to begin in Q2 2026, which has a time-based rate component and a demand response component, is enabled by the system that was put into place years ago. This program is intended to reduce system peak demand, mitigate capacity needs, and encourage cost efficient consumption behaviors. Incentivizing customers to lower consumption during the system’s most constrained hours reduces the need for peak generation resources and provides a mechanism to manage load during tight system conditions or during extreme weather events.

8.2. Environmental Appendix

8.2.1. Air Emissions

It was assumed that current or future generation resources would not exceed CEI South’s allocated annual SO_2 and NO_x emission allowances. CEI South’s fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NO_x emissions, while the cost of emission control equipment and NO_x is factored into any new natural gas-fired facilities, or in the case of a natural gas conversion for Culley Unit 3, that would be selected as part of a portfolio. In 2023 EPA promulgated the Good Neighbor Plan which required 23 states, including Indiana, to further lower existing caps for seasonal NO_x allowances to be allocated to emissions units in the affected states and creating a CSAPR NO_x Ozone Season Group 3 Trading Program which would become effective in the 2024 ozone season. However, on June 27, 2024, the US Supreme Court granted emergency stay petitions, staying implementation of the rule. EPA issued guidance on August 5, 2024, reestablishing the existing CSAPR NO_x Ozone Season Group 2 allowance caps. Air emissions allowance costs are accounted for within IRP modeling.

8.2.2. Solid Waste Disposal

Fly ash from the F.B. Culley facility that meets beneficial reuse specifications is transported off site for beneficial reuse in a cement application, while fly ash that does not meet beneficial reuse specifications is transported for disposal in a permitted local landfill. The F.B. Culley facility completed the conversion of the Unit 3 bottom ash system to a dry system in December 2020 and similarly sends bottom ash to beneficial reuse or transported for disposal in a permitted local landfill. The F.B. Culley facility utilizes a GeoTube Containment Area that collects the bottom ash and drains the filtrate to a lined pond. The collected bottom ash is sent for beneficial reuse or landfilled. Additionally, the F.B. Culley facility completed the construction of a Spray Dryer Evaporator to handle the FGD Wastewater from the scrubber. The East Ash Pond (approximately 10 acres) no longer receives any waste streams and is in final stages of closure. The West Pond (32 acres) completed closure in December 2020. The closure project included the construction of a new geosynthetic lined contact storm water pond that receives the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is sent off-site for beneficial reuse via shipment by river barge from F.B. Culley to a wallboard manufacturer.

8.2.3. Hazardous Waste

CEI South's A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include outage or maintenance related wastes, paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Small Quantity Generators. All hazardous waste is disposed of in accordance with Federal and state regulations.

8.2.4. Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under NPDES wastewater discharge permits issued by the IDEM. A.B. Brown natural gas fired combustion turbines have closed-loop cooling systems, while F.B. Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission ("ORSANCO") regional water quality standards mercury limit of 12 ppt monthly average.

8.3. DSM Appendix

8.3.1.1. DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level and costs of DSM to be offered in CEI South's service territory are important outcomes of the IRP process. The IRP will determine the appropriate level of DSM to include in the preferred resource plan. However, for CEI South, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 3 years CEI South engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to re-affirm the cost effectiveness of the proposed programs.

8.3.1.2. Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure and escalation rates and discount rates. CEI South considers the results of each test and ensures that the portfolio passes the Total Resource Cost test as it includes the total costs and benefits to both the energy company (program administrator) and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test ("UCT")
- Total Resource Cost Test ("TRC")

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

The Participant Cost Test shows the value of the program from the perspective of the energy company's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program to the utility considering only avoided utility supply costs (based on the next unit of generation) in comparison to the utility program costs.

The Ratepayer Impact Measure ("RIM") Test shows the impact of a program on all utility customers through impacts on average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The TRC Test shows the combined perspective of the energy company and the participating customers. This test compares (1) the level of benefits associated with the reduced energy supply costs to (2) the costs incurred by the energy company and by program participants. In completing the tests listed above, CEI South used 6.77% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on December 5, 2023 in Cause No. 45990.

Figure 8-27 - CEI South Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

8.3.2. Gross Savings 2025-2027 Plan

Figure 8-28 - 2025-2027 Approved Plan Gross kWh Energy Savings

	2025		2026		2027	
Sector	Gross kWh Energy Savings	Gross KW Demand Savings	Gross kWh Energy Savings	Gross KW Demand Savings	Gross kWh Energy Savings	Gross KW Demand Savings
Residential	14,377,963	8,184	15,932,490	9,214	15,862,630	8,236
C&I	22,600,000	3,005	25,024,327	3,492	25,400,000	3,279
Total	**36,977,963**	**11,189**	**40,956,817**	**12,706**	**41,262,630**	**11,515**

8.3.3. DSM Programs

CEI South has offered tariff-based DSM resource options to customers for many years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all CEI South's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized CEI South to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938 and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP and HLF.

8.3.4. Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 8-29 - 2025 Electric DSM Operating Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	1,978	74%	474,041	240	350,980	195	0.099	144
Residential Midstream	Residential	1,783	47%	1,841,874	1,033	874,256	581	0.326	276
Home Energy Assessment	Residential	478	100%	377,520	790	377,520	27	0.056	27
In Store Discount	Residential	4,575	100%	457,893	100	457,893	36	0.008	36
Multi Family Energy Solutions	Residential	26	100%	369,015	14,193	369,015	25	0.969	25
Community Connections	Residential	44,864	100%	778,895	17	778,895	24	0.001	24
Residential New Construction	Residential	154	64%	78,637	511	50,609	30	0.197	19

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Income Qualified Weatherization	Residential	837	100%	779,346	931	779,346	83	0.099	83
Marketplace	Residential	7,209	100%	1,618,571	225	1,618,571	603	0.084	603
Residential Behavioral Savings	Residential	49,700	100%	6,125,117	123	6,125,117	1,850	0.037	1,850
Smart Cycle (DLC Change Out)	Residential	3,000	100%	1,477,053	492	1,477,053	3,300	1.100	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,300	100%	0	0	0	1,430	1.100	1,430
Commercial Prescriptive	Commercial	13,047	84%	10,751,737	824	9,031,459	1,709	0.131	1,435
Commercial Midstream	Commercial	32	84%	448,263	14,008	376,541	53	1.658	45
Commercial Custom	Commercial	89	84%	5,600,000	62,921	4,704,000	754	8.468	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0.034	395
Building Optimization	Commercial	10	100%	1,500,000	150,000	1,500,000	20	2.000	20
DSM Portfolio Total		**142,955**	**88%**	**36,977,963**	**259**	**32,483,256**	**11,189**	**0.078**	**10,345**

Figure 8-30 - 2026 Electric DSM Proposed Operating Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	2,638	74%	427,293	162	314,238	166	0.063	122
Residential Midstream	Residential	2,642	48%	1,861,980	705	884,859	587	0.222	279
Home Energy Assessment	Residential	385	100%	473,865	1,231	473,865	35	0.091	35
In Store Discount	Residential	3,300	100%	532,856	161	532,856	40	0.012	40
Multi Family Energy Solutions	Residential	350	100%	369,015	1,054	369,015	25	0.072	25
Community Connections	Residential	28,040	100%	778,895	28	778,895	24	0.001	24
Residential New Construction	Residential	167	64%	78,637	471	50,609	30	0.181	19
Income Qualified Weatherization	Residential	800	100%	784,991	981	784,991	86	0.108	86
Marketplace	Residential	6,100	100%	1,694,556	278	1,694,556	632	0.104	632
Residential Behavioral Savings	Residential	62,000	100%	6,125,117	99	6,125,117	1,850	0.030	1,850
Smart Cycle (DLC Change Out)	Residential	2,500	100%	1,477,053	591	1,477,053	3,300	1.320	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,800	100%	0	0	0	1,430	0.794	1,430
Commercial Prescriptive	Commercial	13,003	84%	12,032,995	925	10,107,640	1,883	0.145	1,582
Commercial Midstream	Commercial	38	84%	567,005	14,921	476,284	82	2.150	69
Commercial Custom	Commercial	93	84%	6,100,000	65,591	5,124,000	754	8.106	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0.034	395
Building Optimization	Commercial	5	100%	1,500,000	300,000	1,500,000	20	4.000	20
DSM Portfolio Total		**143,646**	**88%**	**40,956,817**	**285**	**36,158,538**	**12,706**	**0.088**	**11,836**

Figure 8-31 - 2027 Electric DSM Approved Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	1,724	73%	395,946	230	287,817	141	0.082	103
Residential Midstream	Residential	1,793	48%	1,896,389	1,058	902,894	597	0.333	284
Home Energy Assessment	Residential	748	100%	570,893	763	570,893	44	0.058	44
In Store Discount	Residential	7,275	100%	607,820	84	607,820	43	0.006	43
Multi Family Energy Solutions	Residential	26	100%	369,015	14,193	369,015	25	0.969	25
Community Connections	Residential	44,864	100%	778,895	17	778,895	24	0.001	24
Residential New Construction	Residential	154	64%	78,637	511	50,609	30	0.197	19
Income Qualified Weatherization	Residential	907	100%	790,637	872	790,637	90	0.099	90
Marketplace	Residential	7,893	100%	1,772,227	225	1,772,227	661	0.084	661
Residential Behavioral Savings	Residential	49,700	100%	7,125,117	143	7,125,117	1,850	0.037	1,850
Smart Cycle (DLC Change Out)	Residential	3,000	100%	1,477,053	492	1,477,053	3,300	1.100	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,300	100%	0	0	0	1,430	1.100	1,430
Commercial Prescriptive	Commercial	12,958	84%	12,824,803	990	10,767,584	1,964	0.152	1,649
Commercial Midstream	Commercial	33	84%	675,197	20,461	567,166	72	2.170	60
Commercial Custom	Commercial	93	84%	6,100,000	65,591	5,124,000	754	8.106	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0.034	395
Building Optimization	Commercial	10	100%	1,500,000	150,000	1,500,000	20	2.000	20
DSM Portfolio Total		**146,351**	**88%**	**41,262,630**	**282**	**36,303,727**	**11,515**	**0.079**	**10,631**

8.3.5. Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed Operations and Maintenance ("O&M") cost. For this avoided cost analysis, a 235 MW 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost.

The marginal operating energy costs were based off the modeled CEI South system marginal energy cost from the Preferred Portfolio under Reference Case assumptions. This included estimated capital, variable operation and maintenance and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses.

The table below (Figure 8-32) shows avoided costs when energy efficiency is selected through the IRP modeling process. As energy efficiency competes against other supply side resources and is selected, then the cost of a 235 MW 1x F-class simple cycle gas turbine is avoided.

Figure 8-32 - Avoided Costs

Year	Avoided Capital/ O&M Cost ($/kW)	Transmission & Distribution Avoided Capital Cost ($/kW)	Total Capacity Avoided Cost ($/kW)	Natural Gas Forecast ($/MMBtu)	System Marginal Cost ($/MWh)
2026	$180.11	$13.74	**$193.85**	$3.48	$44.65
2027	$183.95	$13.58	**$197.53**	$3.76	$45.97
2028	$187.87	$13.72	**$201.59**	$4.08	$49.69
2029	$191.87	$14.16	**$206.03**	$4.39	$55.71
2030	$195.95	$14.62	**$210.57**	$4.62	$54.37
2031	$200.13	$14.30	**$214.42**	$4.82	$56.65
2032	20439%	$14.70	**$219.09**	$4.91	$57.73
2033	$208.74	$14.93	**$223.67**	$4.99	$59.41
2034	$213.19	$15.21	**$228.40**	$5.14	$48.46
2035	$217.73	$15.71	**$233.44**	$5.31	$58.75
2036	$222.37	$15.94	**$238.31**	$5.45	$60.34
2037	$227.11	$16.29	**$243.40**	$5.57	$60.95
2038	$231.94	$16.63	**$248.57**	$5.74	$62.16
2039	$236.88	$16.99	**$253.87**	$5.92	$63.85
2040	$241.93	$17.37	**$259.30**	$6.22	$66.94
2041	$247.08	$17.72	**$264.80**	$6.37	$66.63
2042	$252.34	$18.10	**$270.45**	$6.58	$66.70
2043	$257.72	$18.49	**$276.21**	$6.77	$69.91
2044	$263.21	$18.88	**$282.09**	$7.00	$70.70
2045	$268.82	$19.29	**$288.10**	$7.33	$69.87

8.3.6. Estimated Impact on Historical Forecasted Peak Demand and Energy

The load forecast developed by Itron incorporates CEI South's historical DSM in the residential and commercial models to account for historical program savings. The DSM variables help explain historical usage trends. For additional details on the impact of DSM on the forecast see *Technical Appendix Attachment 3.12025 CEIS Long-Term Electric Energy & Demand Forecast Report, Section 5.4 Historical DSM Savings*.

8.3.7. Appliance Saturation Survey

CEI South conducted a residential energy efficiency baseline survey which launched on February 17, 2025 and was closed on February 28, 2025. CEI South fielded forty-seven

(47) questions, which were developed with input from GDS (CEI South's Market Potential Study vendor), Itron, and the OSB. The survey contained a set of core questions with an option for customers to answer additional questions. CEI had 1,048 people who started the survey and 730 who completed the entire survey for a response rate of 5.4% out of the total number of people who received the survey. Survey responses informed the market potential study both qualitative, and quantitative in terms of saturation and efficiency levels of measures. The 2025 CNP Residential Energy Efficiency Baseline Survey presentation can be found in *Technical Appendix Attachment 3.7*. The results of the 2025 Survey will be incorporated into the sales and demand forecasts in future IRPs.

8.4. Risk Appendix

The probabilistic risk assessment allows for the development of portfolio results based on a range of randomly sampled input values. Specifically, it evaluates uncertainty around coal, natural gas, CO_2, and MISO energy prices, peak load, capital costs for new renewable, thermal, and storage resources, and market energy sales. With the uncertainty around the variables defined by probability distributions, the variables were modeled stochastically using Encompass's Monte Carlo sampling capability. Stochastically developed inputs allow for the testing of each portfolio's performance across a wide range of probable market conditions. The development of probability distributions around uncertainty variables, combined with running these distributions through a stochastic process to develop 200 sets of inputs, is key to the probability risk assessment approach. The probability distributions used in the assessment are described in more detail below.

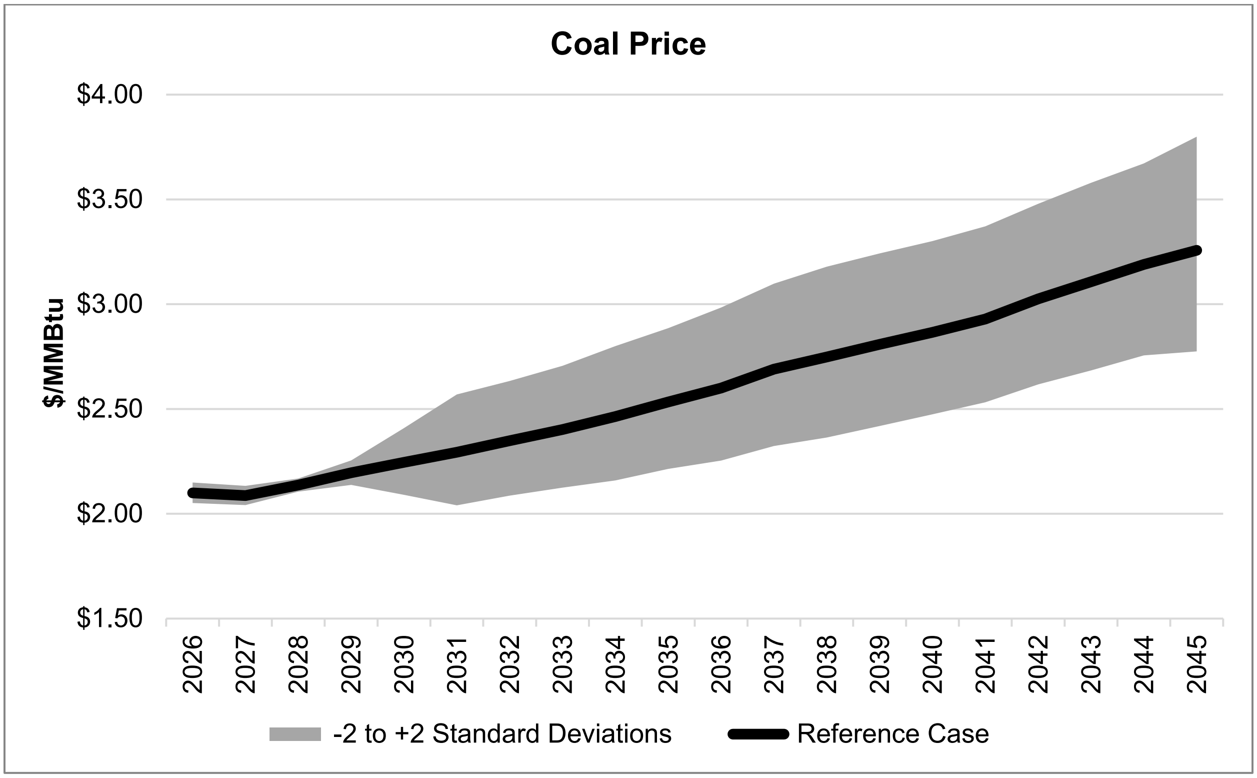
8.4.1. Stochastics (Probabilistic Modeling)

To perform the stochastics (probabilistic modeling), a set of probability distributions that characterize uncertainty was required for each of the key variables described above (coal prices, natural gas prices, MISO energy prices, peak demand, CO_2 prices, capital costs for new resources, and market sales). Monthly lognormal probability distributions were assumed for coal prices, natural gas prices, and peak demand. For the other variables, discrete distributions were developed at varying time intervals: hourly for MISO energy prices, monthly for sales limits, and annually for CO_2 prices and new resource capital costs. The lognormal probability distributions were stochastically simulated together in EnCompass with cross-variable correlation using Monte Carlo Sampling. This produced 200 sets of correlated inputs for coal prices, natural gas prices and peak demand. These stochastic runs in EnCompass assumed 100 percent mean reversion. The discrete distributions for MISO energy prices, CO_2 prices, new resource capital costs, and sales limits were then randomly assigned to each of the 200 stochastic iterations. These input sets were individually run through the dispatch model in EnCompass with each of 12 selected portfolios for a total of 2,400 simulations. The following sections describe the methodologies for developing the stochastic variables.

8.4.1.1. Coal Price Uncertainty

To define the uncertainty around coal prices to be used in the stochastic modeling, 1898 & Co. relied on a base, high and low coal price forecast from U.S. Energy Information Administration's ("EIA") 2025 Annual Energy Outlook ("AEO"). Specifically, 1898 & Co. developed annual standard deviations based on the EIA's Interior Minemouth price forecasts for the Reference Case, High Oil Price Case, and the Alternative Electricity Case. These annual standard deviations were converted to monthly standard deviations, which were then divided by EIA Interior Minemouth Reference Case pricing to arrive at percent standard deviations for coal pricing. The monthly percent standard deviations were then applied to the IRP consensus Reference Case pricing to impute a monthly lognormal probability distribution for coal pricing. These monthly distributions of coal prices were in turn sampled in the stochastic modeling that developed the 200 sets of stochastic inputs. Figure 8-33 displays the base coal forecast as well as two standard deviations from the mean.

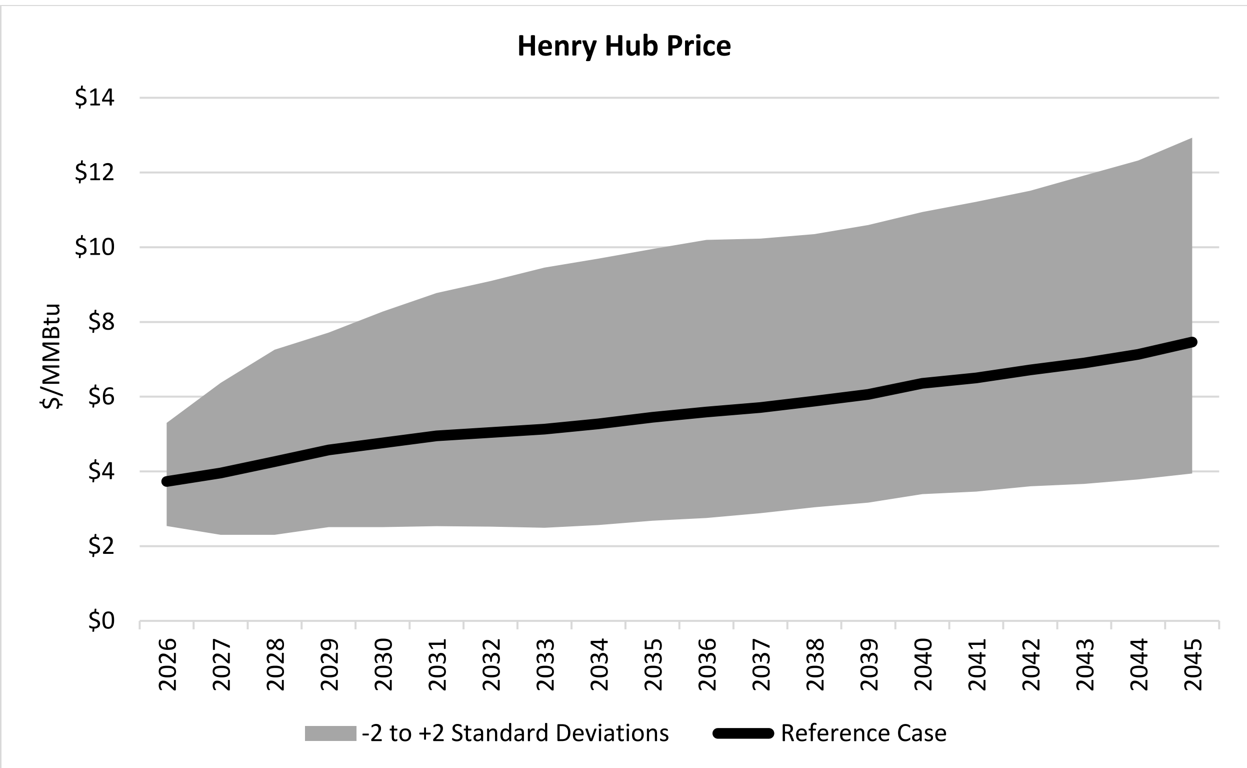
Figure 8-33 - Coal Price Distribution (Nominal$/MMBtu)



8.4.1.2. Natural Gas Price Uncertainty

To define the uncertainty around natural gas prices to be used in the stochastic modeling, 1898 & Co. relied on the base, high and low Henry Hub natural gas price forecast using data from Hitachi (ABB). Specifically, 1898 & Co. developed monthly standard deviations from the base, high and low forecasts, divided the result by the base price forecast to arrive at a percent standard deviation. The monthly percent standard deviations were then applied to the consensus Reference Case pricing to impute a monthly lognormal probability distribution for natural gas pricing. These monthly natural gas price distributions were in turn sampled in the stochastic modeling that developed the 200 sets of stochastic inputs. An illustration of the Reference Case natural gas forecast as well as its uncertainty is given in Figure 8-34.

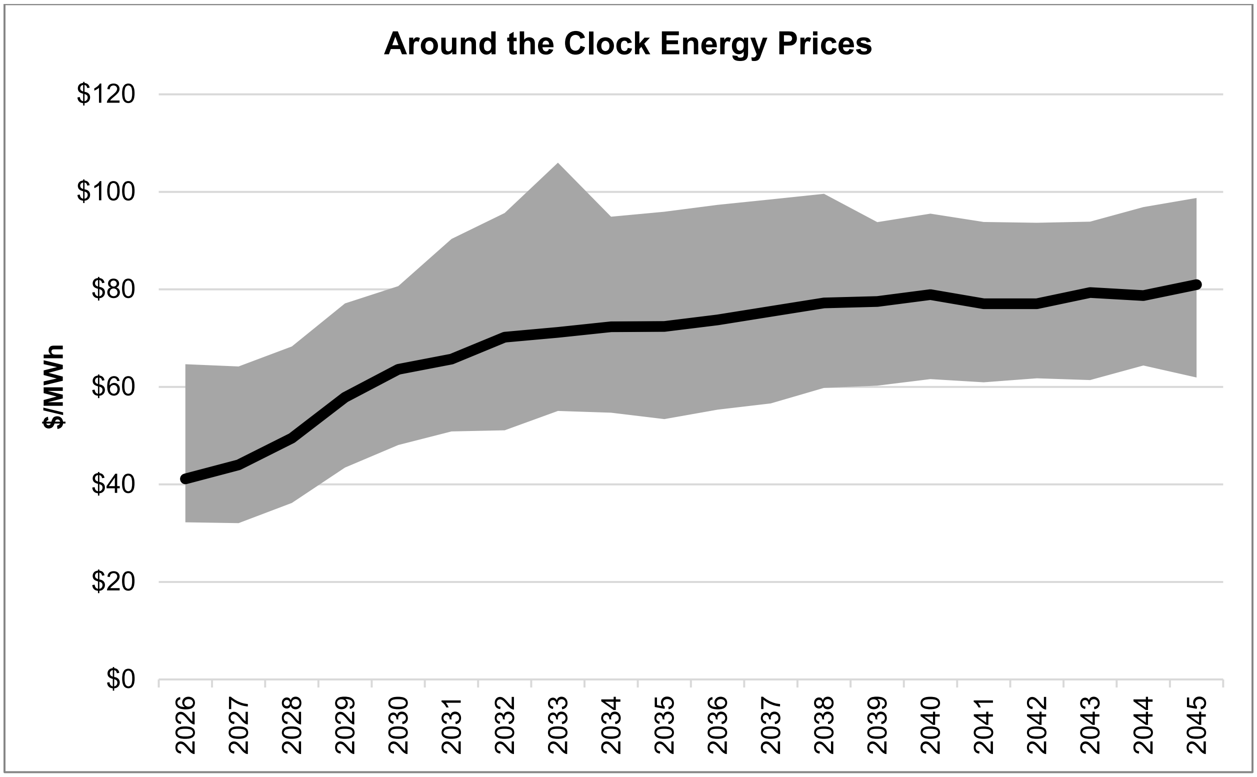
Figure 8-34 - Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu)



8.4.1.3. Energy Price Distribution

1898 & Co. updated energy prices that were input into EnCompass for each of the 200 draws. 1898 & Co. used the national database licensed from Horizon Energy, LLC as the starting point for creating the energy prices. Using the different IRP scenarios, unique energy price forecasts were developed. The energy prices and associated natural gas prices from the scenario model runs were used to develop monthly implied market heat rate curves. These monthly implied market heat rates were applied to the monthly natural gas price for the 200 iterations to arrive at monthly energy prices for each iteration.

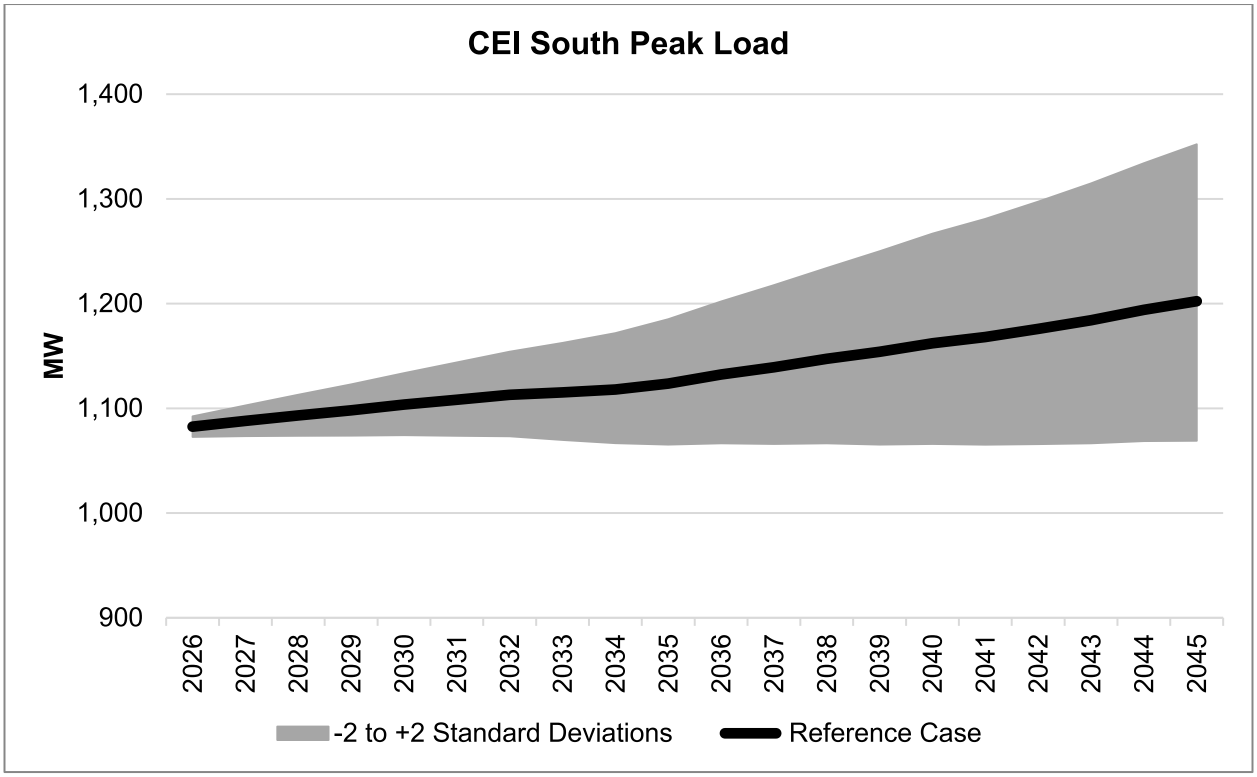
Figure 8-35 - Stochastic Inputs Energy Prices – Market Forecast



8.4.1.4. Load Uncertainty

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, 1898 & Co. relied on monthly peak load forecasts developed by CEI South's vendor, Itron. Itron developed base high and low peak demand forecasts. Using these forecasts, 1898 & Co. calculated monthly peak demand standard deviations which were applied to a lognormal distribution to represent the probability of monthly peak demand within the stochastic modeling framework. Figure 8-36 below shows uncertainty around peak loads.

Figure 8-36 - CEI South Load Distribution (Megawatts)



8.4.1.5. CO_2 Emissions Price Uncertainty

No CO_2 emissions prices are assumed for the Reference Case, rather CO_2 prices are assumed for the High Regulatory scenario. Because of these assumptions, CO_2 price uncertainty is assigned on a discrete basis. Specifically, 1898 & Co. randomly assigned a zero price for CO_2 for 150 iterations out of the 200 iterations of stochastic inputs and the CO_2 price from the High Regulatory scenario for 50 iterations.

8.4.1.6. Capital Cost Uncertainty

1898 & Co. developed base, high, and low capital cost assumptions for renewable, thermal, and storage resources used in the scenario analyses. For technologies that had a purchase option submitted to the 2024 All-Source RFP – namely storage, solar and solar plus storage – the base forecast was developed using the average purchase price for received bids. For wind resources, the technology assessment was combined with data collected for wind Power Purchase Agreements ("PPA") received during the 2024 All Source RFP to create an estimate that reflected current market conditions. The proposals reflect current near-term purchase options and were forecasted through the study period using capital cost estimates from the NREL. The low forecast follows a similar methodology; however, it uses the lowest received purchase price as a starting point and then trends linearly to the NREL reference case cost in 2045. In contrast, the high forecast begins with the highest bid price and then escalates throughout the study period at the assumed inflation rate (2.13%).

For technologies that did not have a purchase option submitted in the recent RFP, the technology assessment provided a starting point for cost estimates. Specifically, for nuclear and thermal technologies, the technology assessment cost estimate was used for a starting price, which was then forecasted to follow the moderate NREL curve. The low forecast follows the same methodology, starting at the technology assessment data point and then following the low NREL cost curve. Finally, the high forecast begins at the same point and then escalates through the study period at the assumed escalation rate.

Since the base, high and low capital costs were developed based on fundamental assumptions and do not conform to a specific probability distribution type, the costs were treated as discrete distributions and assigned to the 200 iterations for inclusion in the stochastic inputs. Low capital costs were assigned to the first 50 stochastic iterations, base (Reference Case) capital costs to the next 100, and high capital costs to the final 50 iterations. Because it is unlikely capital costs would stay high or low for every year of the study period, the order of iterations was randomly shuffled every four years prior to the 50/100/50 iteration assignments. With this approach, any one iteration would have a combination of base, high and low capital costs in four year segments.

The following figures provide examples of capital cost curves from each resource category. Note that these diagrams are provided without the adder for Allowance for Funds Used During Construction ("AFUDC"), which was applied to the capital costs seen in the EnCompass Model.

Figure 8-37 - Lithium-Ion 100 MW/400 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,273	$1,955	$2,591	$1,805
2027	$2,273	$1,955	$2,591	$1,786
2028	$2,273	$1,955	$2,591	$1,765
2029	$2,244	$1,948	$2,646	$1,742
2030	$2,212	$1,942	$2,703	$1,718
2031	$2,227	$1,936	$2,760	$1,729
2032	$2,241	$1,930	$2,819	$1,740
2033	$2,255	$1,924	$2,879	$1,751
2034	$2,269	$1,918	$2,940	$1,762
2035	$2,282	$1,912	$3,003	$1,772
2036	$2,294	$1,905	$3,067	$1,782
2037	$2,307	$1,899	$3,132	$1,791
2038	$2,318	$1,893	$3,199	$1,800
2039	$2,329	$1,887	$3,267	$1,809
2040	$2,340	$1,881	$3,336	$1,817
2041	$2,350	$1,875	$3,407	$1,825
2042	$2,359	$1,869	$3,480	$1,832
2043	$2,367	$1,862	$3,554	$1,838
2044	$2,375	$1,856	$3,630	$1,845
2045	$2,382	$1,850	$3,707	$1,850

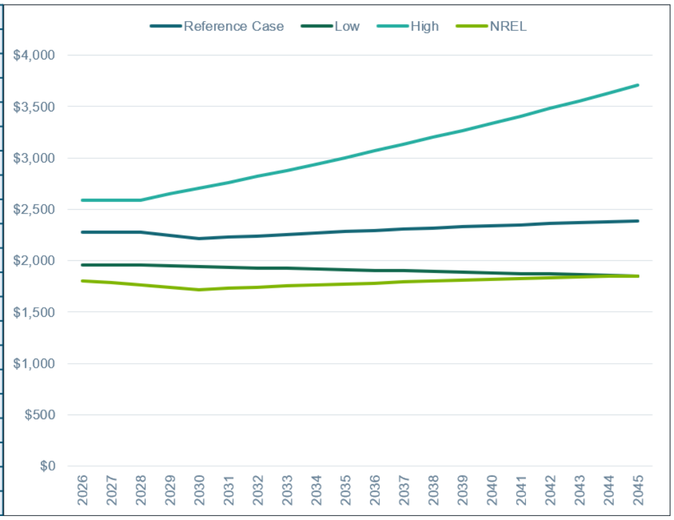


Figure 8-38 - Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,351	$1,895	$2,750	$1,558
2027	$2,351	$1,895	$2,750	$1,525
2028	$2,351	$1,895	$2,750	$1,490
2029	$2,351	$1,895	$2,750	$1,452
2030	$2,287	$1,853	$2,809	$1,413
2031	$2,219	$1,811	$2,868	$1,371
2032	$2,147	$1,769	$2,929	$1,326
2033	$2,071	$1,727	$2,992	$1,279
2034	$1,991	$1,685	$3,056	$1,230
2035	$1,906	$1,643	$3,121	$1,177
2036	$1,916	$1,601	$3,187	$1,183
2037	$1,925	$1,559	$3,255	$1,189
2038	$1,934	$1,517	$3,324	$1,195
2039	$1,943	$1,475	$3,395	$1,200
2040	$1,950	$1,433	$3,467	$1,205
2041	$1,958	$1,391	$3,541	$1,209
2042	$1,965	$1,350	$3,616	$1,213
2043	$1,971	$1,308	$3,693	$1,217
2044	$1,976	$1,266	$3,772	$1,221
2045	$1,981	$1,224	$3,852	$1,224

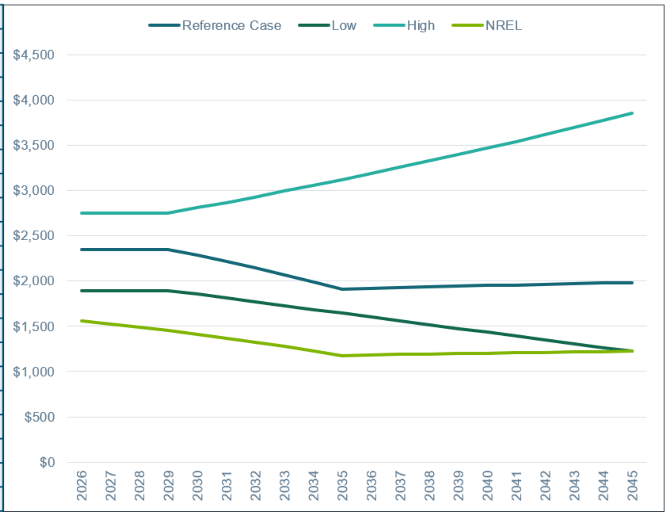


Figure 8-39 – Solar plus Storage Capital Costs Alternate Scenarios (100 + 50 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$3,492	$2,722	$4,500	$2,384
2027	$3,492	$2,722	$4,500	$2,342
2028	$3,492	$2,722	$4,500	$2,296
2029	$3,492	$2,722	$4,500	$2,248
2030	$3,412	$2,681	$4,596	$2,196
2031	$3,359	$2,641	$4,694	$2,163
2032	$3,303	$2,600	$4,794	$2,126
2033	$3,243	$2,559	$4,896	$2,088
2034	$3,178	$2,519	$5,000	$2,046
2035	$3,110	$2,478	$5,106	$2,002
2036	$3,125	$2,438	$5,215	$2,012
2037	$3,139	$2,397	$5,326	$2,021
2038	$3,152	$2,357	$5,440	$2,029
2039	$3,165	$2,316	$5,555	$2,037
2040	$3,176	$2,276	$5,674	$2,045
2041	$3,187	$2,235	$5,794	$2,052
2042	$3,197	$2,194	$5,918	$2,058
2043	$3,206	$2,154	$6,044	$2,064
2044	$3,213	$2,113	$6,173	$2,069
2045	$3,220	$2,073	$6,304	$2,073

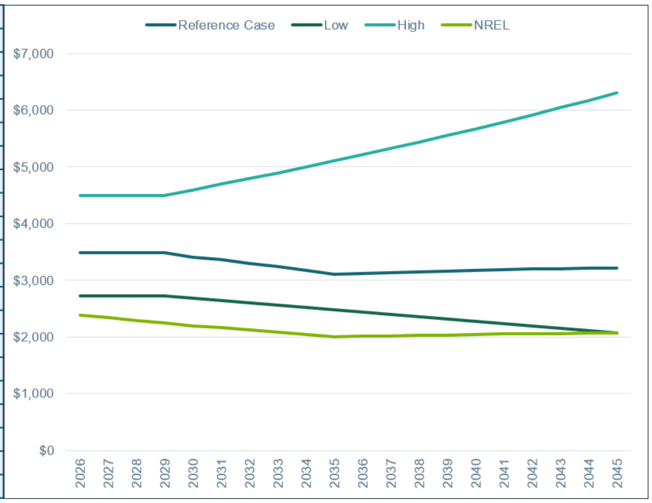


Figure 8-40 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,195	$1,625	$2,611	$1,672
2027	$2,195	$1,641	$2,667	$1,672
2028	$2,193	$1,657	$2,724	$1,671
2029	$2,191	$1,673	$2,782	$1,669
2030	$2,188	$1,689	$2,841	$1,666
2031	$2,211	$1,705	$2,902	$1,684
2032	$2,234	$1,721	$2,963	$1,702
2033	$2,258	$1,737	$3,026	$1,720
2034	$2,281	$1,753	$3,091	$1,737
2035	$2,304	$1,769	$3,157	$1,755
2036	$2,327	$1,785	$3,224	$1,773
2037	$2,351	$1,801	$3,292	$1,791
2038	$2,374	$1,817	$3,363	$1,808
2039	$2,397	$1,833	$3,434	$1,826
2040	$2,420	$1,849	$3,507	$1,843
2041	$2,442	$1,865	$3,582	$1,861
2042	$2,465	$1,881	$3,658	$1,878
2043	$2,488	$1,897	$3,736	$1,895
2044	$2,510	$1,913	$3,816	$1,912
2045	$2,532	$1,929	$3,897	$1,929

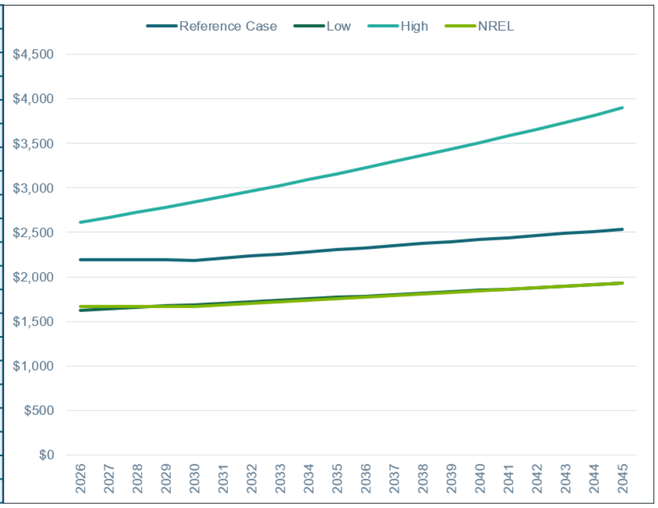


Figure 8-41 – 1x1 J Class Unfired CCGT Capital Costs Alternate Scenarios (620 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,065	$2,061	$2,082	$1,579
2027	$2,092	$2,083	$2,127	$1,599
2028	$2,119	$2,106	$2,172	$1,620
2029	$2,146	$2,128	$2,218	$1,640
2030	$2,173	$2,151	$2,266	$1,661
2031	$2,200	$2,173	$2,314	$1,682
2032	$2,228	$2,195	$2,363	$1,703
2033	$2,255	$2,217	$2,413	$1,724
2034	$2,283	$2,239	$2,465	$1,745
2035	$2,311	$2,262	$2,517	$1,767
2036	$2,342	$2,290	$2,571	$1,791
2037	$2,374	$2,319	$2,626	$1,815
2038	$2,406	$2,348	$2,681	$1,839
2039	$2,438	$2,377	$2,739	$1,864
2040	$2,471	$2,407	$2,797	$1,889
2041	$2,503	$2,436	$2,856	$1,914
2042	$2,536	$2,466	$2,917	$1,939
2043	$2,570	$2,496	$2,979	$1,964
2044	$2,603	$2,526	$3,043	$1,990
2045	$2,637	$2,556	$3,108	$2,016

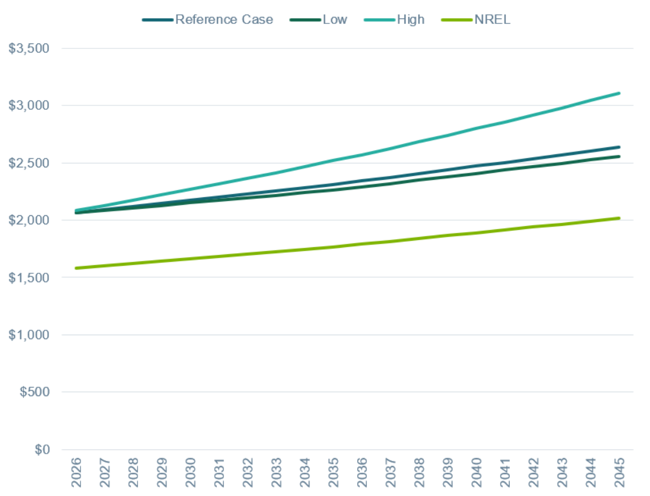
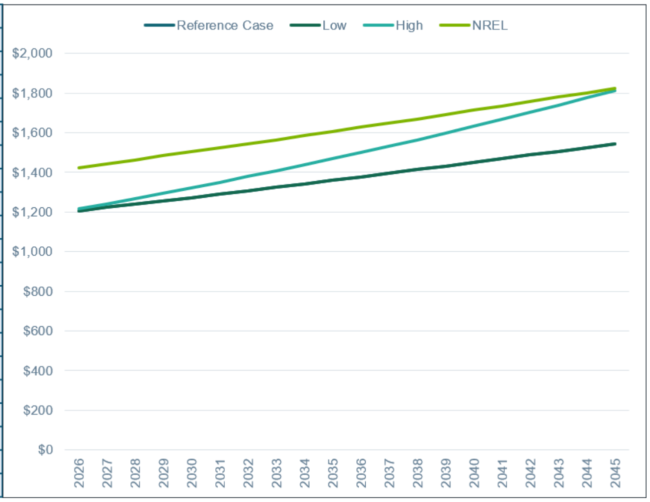


Figure 8-42 – J Class SCGT Capital Costs Alternate Scenarios (426 MW) ($/kW)[42]

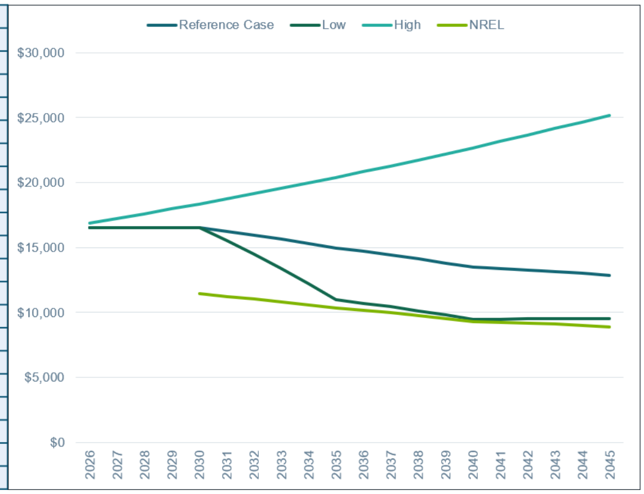
Year	Reference Case	Low	High	NREL
2026	$1,206	$1,206	$1,215	$1,425
2027	$1,223	$1,223	$1,241	$1,444
2028	$1,239	$1,239	$1,268	$1,464
2029	$1,256	$1,256	$1,295	$1,484
2030	$1,273	$1,273	$1,322	$1,504
2031	$1,290	$1,290	$1,350	$1,524
2032	$1,307	$1,307	$1,379	$1,544
2033	$1,325	$1,325	$1,408	$1,565
2034	$1,342	$1,342	$1,438	$1,585
2035	$1,360	$1,360	$1,469	$1,606
2036	$1,378	$1,378	$1,500	$1,627
2037	$1,396	$1,396	$1,532	$1,649
2038	$1,414	$1,414	$1,565	$1,670
2039	$1,432	$1,432	$1,598	$1,692
2040	$1,451	$1,451	$1,632	$1,713
2041	$1,469	$1,469	$1,667	$1,735
2042	$1,488	$1,488	$1,703	$1,757
2043	$1,506	$1,506	$1,739	$1,779
2044	$1,525	$1,525	$1,776	$1,802
2045	$1,544	$1,544	$1,814	$1,824



[42] For combustion turbines, the NREL base, low, and high curves are all identical. As such, the low and Reference Case curves are identical for this analysis. The high curve, as stated previously, is based on inflation and therefore remains unique.

Figure 8-43 – Advanced Nuclear (SMR) Capital Costs Alternate Scenarios (300 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$16,528	$16,528	$16,880	
2027	$16,528	$16,528	$17,239	
2028	$16,528	$16,528	$17,606	
2029	$16,528	$16,528	$17,981	
2030	$16,528	$16,528	$18,364	$11,422
2031	$16,255	$15,523	$18,755	$11,233
2032	$15,962	$14,469	$19,154	$11,031
2033	$15,650	$13,362	$19,562	$10,815
2034	$15,317	$12,201	$19,979	$10,585
2035	$14,963	$10,986	$20,404	$10,340
2036	$14,703	$10,717	$20,839	$10,161
2037	$14,425	$10,432	$21,282	$9,968
2038	$14,128	$10,130	$21,735	$9,763
2039	$13,812	$9,811	$22,198	$9,545
2040	$13,477	$9,473	$22,671	$9,313
2041	$13,378	$9,489	$23,153	$9,245
2042	$13,269	$9,501	$23,646	$9,169
2043	$13,149	$9,509	$24,150	$9,086
2044	$13,017	$9,513	$24,664	$8,996
2045	$12,875	$9,514	$25,189	$8,897



8.4.1.7. Market Sales Limits

In order to ensure the economic viability of portfolios independent of market sales, 1898 & Co. imposed a limit on energy market sales within the stochastic portfolios. This limit follows a discrete distribution with one third of draws randomly assigned 660 MW, one third assigned 330 MW, and one third assigned a 165 MW limit. 660 MW was chosen as the highest sales limit because that is approximately the capability of the physical transmission system today and thus a reasonable boundary for the IRP modeling. The lower limits, scaled to 50% and 25% of the maximum, account for the risk of lower market sales than projected under current model assumptions.

8.4.2. Rate Metric Ranking

Figure 8-44 provides the cost of each portfolio on a per kWh basis.

Figure 8-44 – Portfolio Cost Rate (¢/kWh)

Portfolio Number	Portfolio Description	(¢/kWh)
2	FBC3 NG 2035	6.50¢
1	Reference Case	6.52¢
8	Low Reg	6.58¢
12	Delayed Reference	6.71¢
11	FBC3 Co-Fire	6.74¢
3	FBC3 on Coal	7.05¢
10	Alt High Reg	7.37¢
9	High Reg	7.52¢
5	FBC3 to SCGT	7.53¢
6	Renewable Heavy	7.54¢
7	FBC3 NG with Renewables	7.65¢
4	FBC3 to SMR	7.79¢

8.5. Transmission Appendix

8.5.1. MISO Regional Transmission Planning

MISO performs the NERC functional role of Planning Coordinator on behalf of CEI South. In its NERC functional role of Transmission Planner, CEI South supports MISO’s regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. CEI South is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

CEI South participates in MISO coordinated Seasonal Transmission Assessments (“CSA”) for spring, summer, fall and winter peak loads as applicable. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. CEI South also participates in MISO Generator

Interconnection (“DPP”) and Transmission Service Requests (“TSR”) planning processes as required.

CEI South participates in MISO’s regional Transmission Expansion Plan (“MTEP”). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports the development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved the LRTP Tranche 2.1 portfolio during the MTEP 2024 planning cycle. 24 transmission projects (MISO LRTP ID #19-42) were approved across the MISO Midwest, including ID #35 which includes major transmission investments in the SIGE region. The project has a targeted completion date of 2032 per MISO. The various upgrades included in LRTP project #35 consist of a new 345/138kV, 400MVA transformer at A.B. Brown substation, a new 345kV line from Duff substation to the new 765/345kV Pike County substation (AEP/DEI), a new 345kV line from Duff substation to the F.B. Culley area, and a new 345kV line from the Culley area to the Ohio River Crossing. From the river crossing, the 345kV line will continue to BREC Reid substation. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line from the Ohio River crossing to BREC Reid substation. This project in Kentucky was awarded to Republic Transmission, LLC. CEI South, as the incumbent transmission owner, is responsible for all other modifications required for the project, apart from the terminal at BREC Reid substation. The overall project cost will be shared according to MISO’s Tariff. The Tranche 2.1 projects will provide regional economic benefits and enhanced grid reliability for the CEI South region looking into the future as generation and load profiles change across the Midwest.

8.5.2. Annual Transmission Assessment

CEI South’s most recent transmission assessment was completed in 2025. The study used MISO MTEP24 models for the year 2029 representing transmission system conditions in the winter season, summer season, and off-peak, light load conditions. The study used CEIS transmission system performance criteria as documented in VEC-008 Electric Transmission Planning Criteria as a measure to determine the strength of the SIGE transmission system. Siemens PTI PSS/E (version 35.6) software was used to conduct the assessment. The study also uses SIGE transmission ratings methodology as documented in VEC-014 which was applied to all existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson ("FDNS") solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled, and VAR limits applied automatically. Dynamic simulations were not completed in 2025, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with the MTEP24 annual assessment with MISO.

The scope of this 2025 study involved several key assessments as shown below.

- Overall Reliability Assessment using NERC TPL-001 "Transmission System Planning Performance Requirements" criteria
- Reactive Power Deficiency Assessment
- Assessment of MISO Tranche 2.1 approved projects
- SIGE Import and Export Capability Assessment
- Review of the 2025 Long-Range Distribution Plan

Overall, the CEI South Bulk Electrical System (100kV and above) is expected to be stable and perform well through 2034. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, CEI South plans projects to mitigate the violations.

8.5.3. DSM Impacts on Transmission and Distribution Systems

Potential future DSM interconnection requests are currently being studied, per the planning criteria outlined in VEC-008 Electric Transmission Planning Criteria (*Technical Appendix Attachment* 3.9). If VEC-008 does not address applicable planning criteria, CEI South defaults to MISO's criteria.

At this time, no controllable loads or demand side management resources exist on CEI South's transmission system.

8.6. Public Advisory Process Appendix

As defined by 170 IAC, the public advisory process refers to a set of procedures that provide customers and interested parties with the opportunity to receive information from the utilities, provide input for the utility to consider in the development of the IRP, and comment on a utility's IRP.

Highlights:

- CEI South views the public as an essential partner in developing our integrated resource plan and therefore strives to conduct an inclusive stakeholder process that encourages feedback.

- CEI executive leadership and subject matter experts attended public meetings to hear feedback and respond to questions.

- CEI South held four public (in person and virtual) meetings. An average of 70 individuals, representing local residents and over 30 organizations, registered for the public meetings.

- Three virtual technical meetings were held with interested stakeholders who signed an NDA. Leadership and subject matter experts attended the technical meetings to hear feedback and respond to questions.

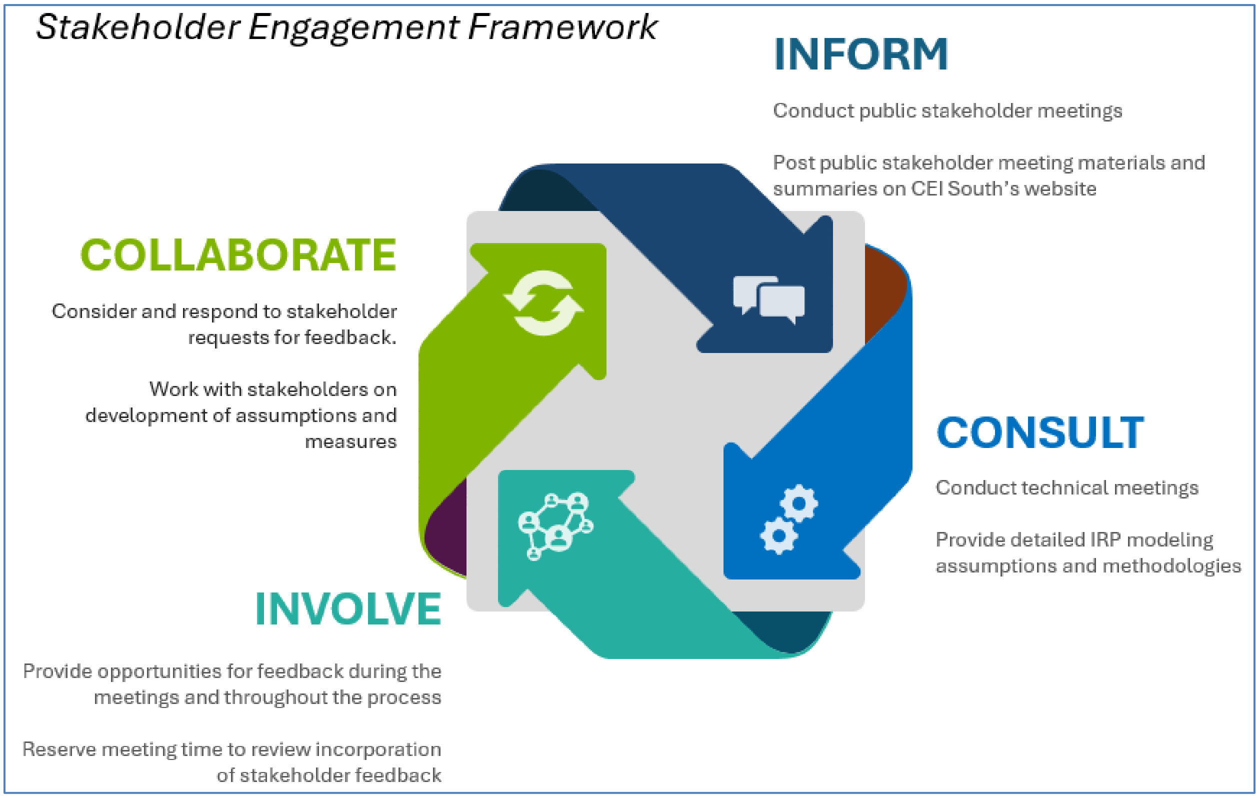
- Stakeholder feedback made an impact on various aspects of the IRP, including assumptions, scenarios, sensitivities, and scorecard metrics.

8.6.1. Foundational Elements

Framework

Ensuring meaningful and sustained stakeholder engagement is crucial to the public advisory process. CEI South's Stakeholder Engagement Framework serves as a guide for fostering substantive and impactful discourse. The Framework is built on four objectives: Inform, Consult, Involve, and Collaborate. Figure 8-45 highlights the alignment among a sample of CEI's engagement activities and the Framework objectives.

Figure 8-45 - Stakeholder Engagement Framework



Stakeholders

CEI South's IRP development is a robust process involving input from many stakeholders, including, but are not limited to, CEI South residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials.

8.6.2. Engagement Resources and Strategies

Given the significant impact IRP decisions can have, conducting the IRP with transparency and full participation from interested stakeholders is essential. CEI South implemented engagement resources and strategies to encourage wide participation.

Engagement Resources

Website

Throughout the 2025 IRP process, CEI South's IRP website[43] served as an information hub for stakeholders. Meeting materials (presentations and post-meeting summaries) as well as the registration links for public meetings were published on the site. Prior IRP materials are also available on the website.

Meeting Notifications

CEI South maintains a confidential IRP stakeholder contact list. With over 300 individual contacts, the list includes CEI South customers, advocates, technical/industry experts, regulators, elected officials, etc. The list is updated throughout the IRP process to ensure new registrants or interested individuals are added. Those on the list received several meeting-related notifications: 1) invitations and reminders to register for meetings via the posted registration link, 2) meeting reminders for registrants, 3) posting of meeting presentation prior to the meeting, and 4) posting of meeting summary after the meeting.

Email Communications

CEI South continued to use a dedicated IRP email address for IRP-related communications. The simple and singular email address provided an easy method for stakeholders to stay involved and engaged outside the public meetings. Stakeholders' written requests for information and CEI South's subsequent responses were also administered through irp@centerpointenergy.com.

File Share

Technical stakeholders, with signed NDAs, were provided access to a secure file share site. The site served as a repository for modeling files and other detailed data and inputs used in the development of the 2025 IRP. The data release schedule and data type were included in the public and Tech-to-Tech meeting presentations.

Engagement Strategies

Stakeholder Meetings

CEI South again engaged 1898 & Co., a third-party consultant and facilitator, to assist in facilitation and support CEI SOUTH's focus on conducting the IRP with full participation from stakeholders. In collaboration with 1898, CEI South hosted four public stakeholder meetings and three technical meetings during the 2025 IRP process. Highlighting the

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[43] CEI South, Integrated Resource Plan website available at https://www.centerpointenergy.com/irp

importance of the meetings, CEI South executive leadership actively participated as presenters and subject matter experts.

Presentations and discussions covered various issues regarding inputs, assumptions, risks, modeling methodology, planned sensitivities and analytical results. To ensure ample opportunity for participants to ask questions, provide feedback, and share information, designated Q&A and feedback periods were included in the agendas. If feedback was received following the meetings, questions were answered via e-mail (irp@centerpointenergy.com) and/or during subsequent public or tech-to-tech meetings, as appropriate.

Public Meetings

In a continued effort to remove barriers to participation, CEI South provided both in-person and virtual attendance options. The CenterPoint Plaza in Evansville, Indiana served as the meeting location for the in-person option. Meeting presentations and meeting summaries, in question-and-answer format, were posted to CEI South's IRP website seven calendar days prior to the meeting and 15 calendar days following the meeting, respectively.

Figure 8-46 is a summary of the stakeholder meetings, see *Technical Appendix Attachment 4.2 Stakeholder Materials* for a comprehensive account of stakeholder meetings, presentations, and meeting summaries.

Figure 8-46 - 2025 Stakeholder Meeting Schedule

Meeting one laid the foundation of CEI South's IRP by providing an overview of the IRP process, metrics, inputs, and assumptions. In the spirit of continuous improvement, past stakeholder feedback and 2025 IRP enhancements were also covered.

Meeting two, as with meetings three and four, opened with a review of stakeholder feedback and requests. Presenters also provided updates for ongoing work and furthered the discussion of inputs, modeling assumptions, portfolio methodology. A preview of the draft Reference Case modeling was also provided.

2025 IRP Enhancements

1. *5 pillar-focused score card*
2. *Refreshed IRP layout*
3. *Expanded sensitivity analysis*
4. *Collaboration with Transmission & Distribution*
5. *Additional analysis of underserved energy*
6. *Data release schedule*

Meeting three began with an update on CEI South's generation transition timeline, followed by a review of stakeholder feedback and requests. Topics included the DSM Market Potential Study results, updates on scenario revisions and probabilistic modeling, as well as initial scenario optimization and deterministic portfolio results.

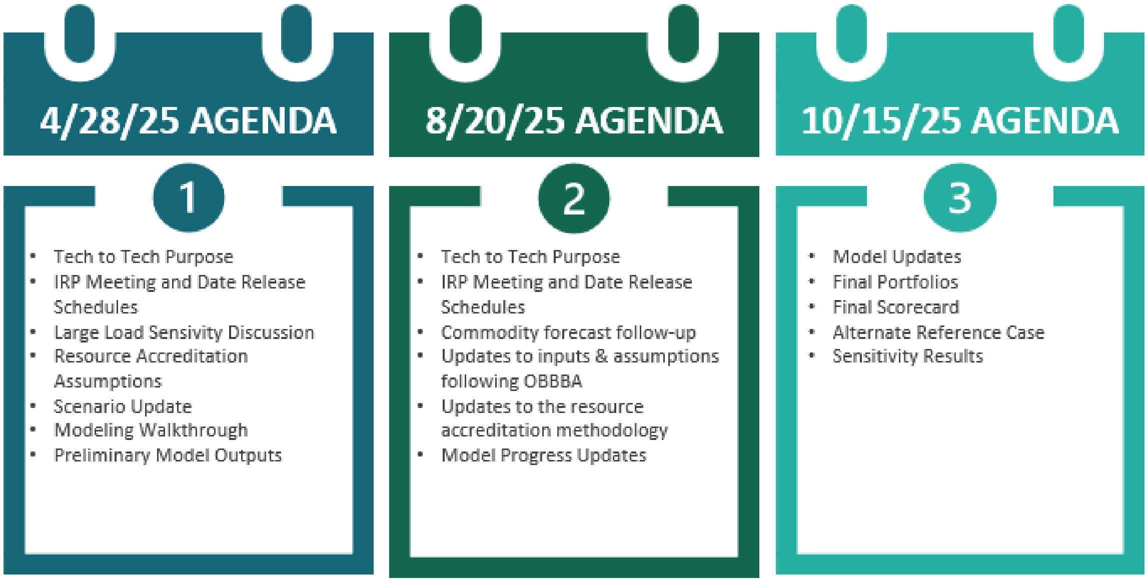
Meeting four also started with stakeholder feedback and requests. The last of the stakeholder meetings, meeting four covered the Preferred Portfolio, Alternative Preferred Portfolio and near-term action plan, as well as examined each portfolio's capacity, energy mix, and associated benefits and challenges. Presenters also shared the detailed risk metrics via a scorecard, reviewed an alternate reference case and optimization outcomes, presented sensitivity analyses, and concluded with a summary of key takeaways.

Tech-to-Tech

Tech-to-Tech meetings were held virtually and facilitated by 1898 & Co. While the meeting dates were made public, attendance was limited to self-identified technical stakeholders with executed NDAs. NDAs were provided to technical stakeholders upon request. Members of Indiana Office of Utility Consumer Counselor, Citizens Action Coalition, Reliable Energy, Sierra Club, State Utility Forecasting Group, and Indiana Utility Regulatory Commission staff were invited to attend these meetings.

The meetings allowed CEI South to share and consult with technical stakeholders on detailed, and often confidential, modeling assumptions and inputs. They also had the added benefit of increasing transparency in the planning process. Tech-to-Tech meeting dates and agendas are listed below (Figure 8-47):

Figure 8-47 - 2025 Tech-to-Tech Meetings



In addition to Tech-to-Tech meetings and public stakeholder meetings, CEI South met with individual stakeholders on various topics. For example, CEI South met several times with the CAC on Energy Efficiency modeling inputs.

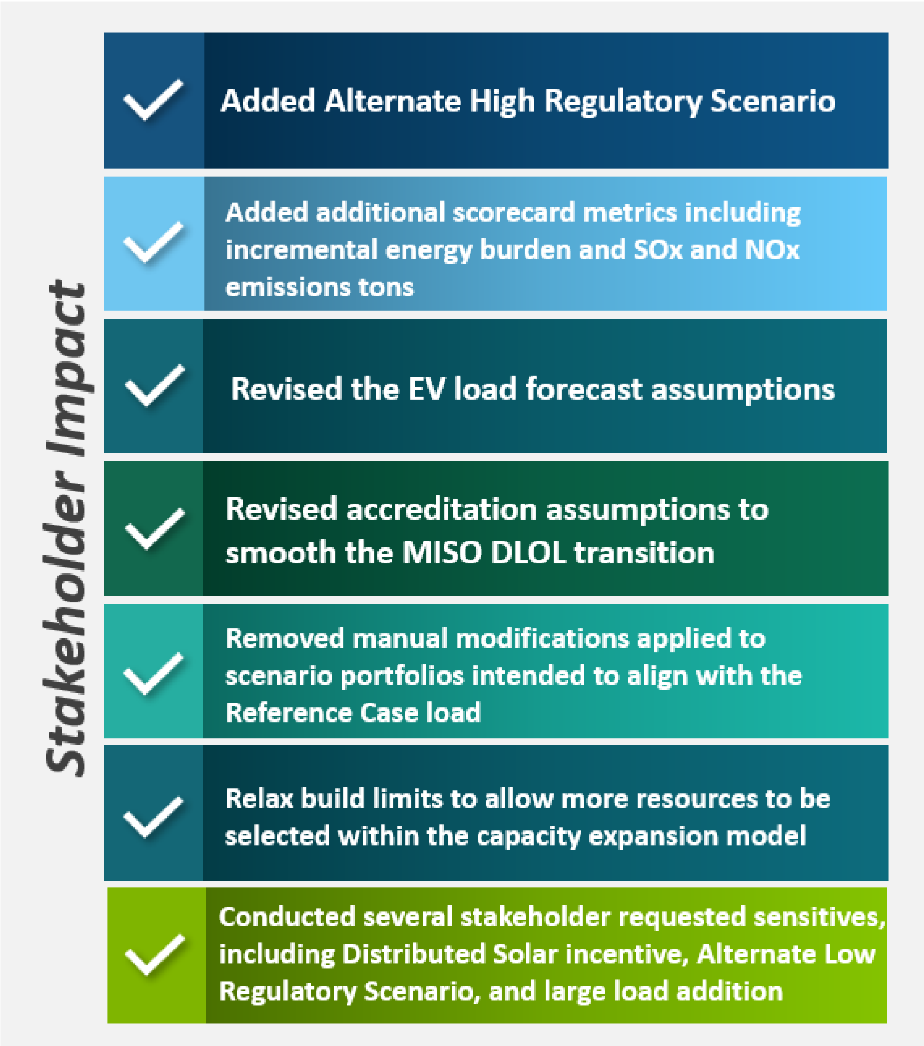
8.6.3. Stakeholder Input

As discussed in Section 8.6.2, CEI South provided multiple avenues for engagement throughout the 2025 IRP process – dedicated Q&A and feedback time during public meetings; use of the IRP email address for written feedback/requests; Tech-to-Tech meetings between public meetings; and individual meetings upon request.

Critical to the IRP, feedback was reviewed, responded to, and incorporated as applicable.

In recognition of the importance of the received feedback, Figure 8-48 is a summary of key feedback that was ultimately included in the 2025 IRP analysis. For a full list, including suggestions not taken, see the *Technical Appendix Attachment 4.2 Stakeholder Materials*.

Figure 8-48 - Summary of Key Stakeholder Input



8.6.4. Data Requests Summary

During the public stakeholder process CEI South received seven data requests from the Citizens Action Coalition, Clean Grid Alliance, Reliable Energy, Sierra Club, Solar United, and State Utility Forecasting Group. These data requests and CEI South's response can be found in the *Technical Appendix Attachment 4.2 Stakeholder Materials*.

8.7.5 DSM OSB Presentations and Data Requests

CEI South collaborates with the CenterPoint Energy Oversight Board (which consists of CEI South, the OUCC, and CAC) on a monthly basis to discuss energy efficiency programs, results, and solicits feedback on program design and funding. This same collaborative group was utilized to discuss DSM in the 2025 Market Potential Study and the development of energy efficiency and demand response inputs into the IRP. CEI South held seven meetings with the kickoff meeting occurring in-person at our Indianapolis office. The meeting dates and topics are listed in Figure 8-49 below, OSB stakeholder presentations can be found in *Technical Appendix Attachment 8.1 2025 MPS Slide Decks for Stakeholders*. This process allowed for robust discussion on topics to drive consensus, where possible, with several data requests and responses which can be found in *Technical Appendix Attachment 8.2 2025 DSM Data Requests and Responses*.

Figure 8-49 - DSM Oversight Board Meetings

Date	Discussion Topic
December 11, 2024	Integrated Gas & Electric Market Potential Study Kickoff
February 5, 2025	Data Request Response Updates/Observations; Measure Lists
March 6, 2025	Initial Demand Response Program Assumptions and Historical Performance Benchmarking
March 13, 2025	Additional Interruptible & Aggregation Discussion
April 17, 2025	Draft Demand Response Potential and EE Measure Assumptions
May 22, 2025	Draft EE Potential Results and Refined Demand Response Potential Results
June 30, 2025	Final EE Results and Initial IRP Inputs

Technical Appendix Attachments

Chapter 9

Attachment 1.1 Non-Technical Summary

Attachment 2.1 2024 All-Source Request for Proposal & Report

Attachment 2.2 2025 Technology Assessment Summary (Confidential)

Attachment 2.3 Transmission Study (Confidential)

Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report

Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs (Confidential)

Attachment 3.3 CEIS 2024 System Hourly Load

Attachment 3.4 CEIS Electric 2025-2027 DSM Plan

Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)

Attachment 3.6 2025 DSM Market Potential Study

Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey

Attachment 3.8 CEIS Distribution System Long Range Planning Report

Attachment 3.9 VEC-008 Electric Transmission Planning Criteria

Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)

Attachment 4.2 Stakeholder Materials

Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)

Attachment 6.2 Large Load Study Results (Confidential)

Attachment 8.1 2025 MPS Slide Decks for Stakeholders

Attachment 8.2 2025 DSM Data Requests and Responses

IRP Rule Requirements Cross Reference Table

Chapter 10

IRP Rule Requirements Cross Reference Table

Rule	Section(s)
170 IAC 4-7-2 Integrated Resource Plan Submission Section 2	
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:	
(1) The IRP.	2025 IRP submitted on December 5, 2025
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	8 Technical Appendix; 9 Technical Appendix Attachments
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.	Executive Summary (Non-Technical Summary Document)
The utility shall make the IRP summary readily accessible on its website.	www.centerpointenergy.com/irp

Rule	Section(s)
170 IAC 4-7-2.6 Public advisory process Sec. 2.6	
(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(c) The utility shall solicit, consider and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(d) The utility retains full responsibility for the content of its IRP.	n/a
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(2) The utility may hold additional meetings.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(3) The schedule for meetings shall:	2.4 Stakeholder Engagement;

Rule	Section(s)
(A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
170 IAC 4-7-4 Integrated resource plan contents Sec. 4	
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.	3.1.4 Reference Case
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	8.1.2 Overview of Past Forecasts
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	3.1.5 Alternative Scenarios
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	3.7.1 Current Resource Mix
(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.	3.7 Resource Options; 4 Portfolio Development and Evaluation
(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.	3.7 Resource Options
(7) The resource screening analysis and resource summary table required by section 7 of this rule.	3.7 Resource Options; Figure 3-40; Figure 3-41
(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.	4 Portfolio Development and Evaluation
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(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.	7 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	11 List of Acronyms/Abbreviations with Definitions; 2 Resource Planning Process; 4 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If	9 Technical Appendix Attachments

Rule	Section(s)
the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use. 14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	3.7 Resource Options; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report; 8.1.1.1 Energy Data; 8.1.1.4 Equipment Efficiencies and Market Share Data
(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.	8.1.1.4 Equipment Efficiencies and Market Share Data
(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.	8.1.5 Advanced Metering Infrastructure and Continuous Improvement
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).	Executive Summary Section V. Stakeholder Process
(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	3.8 Transmission Planning and Distribution Planning; 4.1.1.1.3 Distributed Generation Resource Portfolios;

Rule	Section(s)
(D) load forecasting.	9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	2.11.2 Modeling Tools
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	5.1.8 Fuel Inventory and Procurement Planning
(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.	8.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	3 Forecasts and Key Modeling Assumptions; 4 Portfolio Development and Evaluation
(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.	2.1 Planning Scenarios; 2.6 Reference Case; 2.7 Alternative Scenarios; 3.5 Environmental Regulations
(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.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(25) A description and analysis of the utility's Reference Case scenario, sometimes referred to a business as usual case or reference case. The Reference 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.	2.6 Reference Case

Rule	Section(s)
(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 Reference Case scenario need not align with the utility's preferred resource portfolio.	
(26) A description and analysis of alternative scenarios to the Reference Case scenario, including comparison of the alternative scenarios to the Reference Case scenario.	2.7 Alternative Scenarios
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.	3.8 Transmission and Distribution Planning 8.5.1 MISO Regional Transmission Planning 9 Technical Appendix Attachment 3.9 VEC-008 Electric Transmission Planning Criteria
(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;	2 Resource Planning Process; 3 Forecasts and Key Assumptions; 4 Portfolio Development and Evaluation; 8.1.1.5 Load Forecast Continuous Improvement; 8.6 Public Advisory Process Appendix;

Rule	Section(s)
(ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report; 9 Technical Appendix Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs (Confidential); 9 Technical Appendix Attachment 3.6 2025 DSM Market Potential Study
(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.	8.3.5 Avoided Costs
(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.	Executive Summary; 2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	3.7 Resource Options; 3.9.1 Resource Availability 3.8.4 Transmission Facilities as a Resource;
170 IAC 4-7-5 Energy and demand forecasts Sec. 5.	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following:	8.1.4 Load Shapes; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-

Rule	Section(s)
(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.	Term Electric Energy & Demand Forecast Report; 9 Technical Appendix Attachment 3.3 CEIS 2024 System Hourly Load
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	8.1.2 Overview of Past Forecasts; 9 Technical Appendix Attachments Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(3) Actual and weather normalized energy and demand levels.	8.1.2 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.	8.1.2 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	3.1.4 Reference Case
(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.	8.1.2 Overview of Past Forecasts
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	9 Technical Appendix Attachments 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(8) Justification for the selected forecasting methodology.	9 Technical Appendix Attachments 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(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.	8.1.1.5 Load Forecast Continuous Improvement
(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.	n/a
(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.	3.1.5 Alternate Scenarios

Rule	Section(s)
(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.	3.1 Load Forecast; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
170 IAC 4-7-6 Description of available resources	
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: The net and gross dependable generating capacity of the system and each generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	3.7.1 Current Resource Mix
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	3.7.1 Current Resource Mix; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)
(3) A fuel price forecast by generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP

Rule	Section(s)
	Alternate Reference Stochastics Model (Confidential)
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and(D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	8.2 Environmental Appendix
(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.	8.5 Transmission Appendix
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. (a)(6) shall be provided for each year of the future planning period.	3.7 Resource Options; 8.3 DSM Appendix
The information listed in subdivision (a)(1) through (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Included in Sec. 6 (a)(1) through (a)(4) and in subdivision (a)(6)
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	3.7.2.14 Innovative Rate Design
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters. (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined.	3.7.2.10 Energy Efficiency; 3.7.2.10.1 DSM Market Potential Study; 3.7.2.11 Demand Response; 3.7.2.13 DSM Improvements Based on Stakeholder Feedback;

Rule	Section(s)
(C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	9 Technical Appendix Attachment 3.6 2025 DSM Market Potential Study
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (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 non-dispatchable resources. (iv) Additional transmission facilities necessitated by the resource. (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. (C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.	3.7 Resource Options; 3.9.1 Resource Availability; 9 Technical Appendix Attachment 2.2 2025 Technology Assessment Summary (Confidential); 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (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. (B) A description of the timing, types of expansion and alternative options considered. (C) The approximate cost of expected expansion and alteration of the transmission network. (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby	3.8.4 Transmission Facilities as a Resource; 8.5 Transmission Appendix

Rule	Section(s)
increasing the utilization of geographically constrained cost-effective resources. (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.	
170 IAC 4-7-7 Selection of resources	
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	N/A
170 IAC 4-7-8 Resource portfolios Sec. 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.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(b) With regard to candidate resource portfolios, the IRP must include the following: (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(25) of this rule. (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per	4 Portfolio Development and Evaluation; 8.4.2 Rate Metric Ranking

Rule	Section(s)
kilowatt-hour delivered, with the interest rate specified.	
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio. (2) Identification of the standards of reliability. (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio. (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.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(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.	5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(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.	8.5.3 DSM Impacts on Transmission and Distribution Systems
(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.	5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio: 7.2.6 Ability to Finance the Preferred Portfolio; 8.3.5 Avoided Costs; 8.4.2 Rate Metric Ranking; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following:	Executive Summary; 1 Integrated Resource Planning; 2 Resource Planning Process;

Rule	Section(s)
(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.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(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.	2.11.3 Process Enhancements; 3.7.2.13 DSM Improvements Based on Stakeholder Feedback; 3.7.2.14 Innovative Rate Design; 7.2.7 Continuous Improvement; 8.1.1.5 Load Forecast Continuous Improvement; 8.1.5 Advanced Metering Infrastructure Continuous Improvement; 8.3.7 Appliance Saturation Survey
(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 which would cause the forecasted relationship between supply and demand for electric service to be in error.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio; 7 Short Term Action Plan

Rule	Section(s)
170 IAC 4-7-9 Short term action plan Sec. 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.	7 Short Term Action Plan
(b) The short-term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must act or incur expenses during the three (3) year period.	7 Short Term Action Plan
(c) The short term action plan must include, but is not limited to, the following: (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.	7 Short Term Action Plan
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives.	3.7.2.10 Energy Efficiency; 3.7.2.10.1 DSM Market Potential Study; 7.2 Discussion Of Plans For The Next 3 Years
(3) The implementation schedule for the preferred resource portfolio.	7.3 Schedule
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	7 Short Term Action Plan; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(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.	7.1 Differences Between the Last Short Term Action Plan from What Transpired

List of Acronyms and Abbreviations

Chapter 11

List of Acronyms/Abbreviation

1898 & Co.	1898 & Co., a part of Burns & McDonnell
AAR	Ambient Adjusted Rating
ABB	Power Consulting Company (Hitachi Predecessor)
ABB	A.B. Brown Generating Station
ACE	Affordable Clean Energy
ADR	Aggregation Demand Response
AEO	Annual Energy Outlook
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
ATB	Annual Technology Baseline
ATC	Around the Clock
AUPC	Average Use Per Customer
BAU	Business as Usual
BES	Bulk Electric System
BESS	Battery Energy Storage System
Btu	British Thermal Unit
BYOT	Bring Your Own Thermostat
CAA	Clean Air Act
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CRL	Combustion Residual Leachate
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
DC	Direct Current
DCP	Distributed Capacity Procurement
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control

DLOL	Direct Loss of Load
DPP	Definitive Planning Phase
DR	Demand Response DSM Demand Side Management
DSMA	Demand Side Management Adjustment
eCFR	Electronic Code of Federal Regulations
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
$EFOR_d$	Equivalent Forced Outage
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ERAS	Expedited Resource Addition Study
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GAO	General Administrative Order
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GET	Grid Enhancing Technology
GS	General Service
GW	Gigawatt
GWh	Gigawatt Hour
GWP	Global Warming Potential
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator

ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LCR	Local Clearing Requirement
LDES	Long Duration Energy Storage
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
Li-ion	Lithium-ion
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LP	Large Power
LRZ	Local Resource Zone
LRTP	Long-Range Transmission Plan
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Plan
MVAR	Dynamic VAR Support
MW	Megawatt
MWh	Megawatt Hour
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NT	Near-term
NTG	Net to Gross
NYMEX	New York Mercantile Exchange
OBBBA	One Big Beautiful Bill Act
O&M	Operation and Maintenance
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRM	Planning Reserve Margin

PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	Photovoltaic
PY	Planning Year
RBDC	Reliability Based Demand Curve
RAN	Resource Availability and Need
RERRA	Relevant Electric Retail Rate Authority
RF	ReliabilityFirst
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RRA	Regional Resource Assessment
RS	Residential
RTO	Regional Transmission Operator
SAC	Seasonal Accredited Capacity
SAE	Statistically Adjusted End-use
SCGT	Simple Cycle Gas Turbine
SCR	Short Circuit Ratio
SGS	Small General Service
SIGE	Southern Indiana Gas and Electric
SIGECO	Southern Indiana Gas and Electric Company
SMR	Small Modular Reactor
Sox	Sulfur Oxide
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TOU	Time of Use
TRC	Total Resource Cost
TSR	Transmission Service Request
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
V	Volt
VAR	Volt-Amp Reactance
VPP	Virtual Power Plant
VER	Variable Energy Resources
WN	Weather Normalized
ZLD	Zero Liquid Discharge