BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 114
IURC 2019 CCGT Order

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ*, 8-1-8.5-1 *ET SEQ.*, AND 8-1-8.8 - 1 *ET SEQ.*	)	CAUSE NO. 45052 APPROVED: APR 24 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for a new duct-fired F-class 2x1 combined cycle gas turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. Petitions to intervene were filed by the Vectren Industrial Group; Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); SABIC Innovative Plastics Mt. Vernon, LLC; St. Joseph Energy Center, LLP; St. Joseph Phase II LLC; and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony. The Indiana Utility Regulatory Commission ("Commission") held an evidentiary hearing at 9:30 a.m. on October 9, 2018, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana.

Based upon the applicable law and the evidence presented, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published as required by law. Vectren South is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Vectren South is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Vectren South may seek Commission approval of Certificates of Public Convenience and Necessity. Accordingly, the Commission has jurisdiction over Vectren South and the subject matter of this proceeding.

2. **Vectren South's Characteristics.** Vectren South is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Vectren South provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Vectren South's electric utility business. Vectren South renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power for residential, commercial, industrial and municipal uses. Vectren South furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick Unit 4 (150 MW[1]). Vectren South procures 100% of its coal supply from mines located in Indiana.

[1] Represents Vectren South's ½ interest in Warrick Unit 4, a 300 MW unit.

Vectren South's operations are subject to federal, state and local rules promulgated and/or implemented by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Overview of the Evidence.

A. Condition of Current Fleet.

i. Vectren South. The main drivers behind Vectren South's proposal are the age and operating characteristics of Vectren South's existing baseload capacity and the upcoming deadlines for significant capital investments to address environmental regulations. Mr. Wayne D. Games, Vice President of Power Supply at Vectren South, testified regarding the condition of Vectren South's current generation fleet and the challenges facing the fleet. He testified Vectren South's fleet consists of five coal-fired baseload units totaling 1,000 MW. Mr. Games further testified that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of Vectren South's coal-fired units. Instead of running continuously, Vectren South's units are now cycled up and down throughout the day, or are shut down altogether, decreasing unit efficiency and increasing wear and tear on the units. Mr. Games testified that because the units were not designed to cycle in this manner, the units cannot effectively compete with gas units in particular, which have far better operating flexibility. Continued market reforms are exacerbating this issue and jeopardizing unit availability and reliability.

Mr. Games also explained that the individual units face additional operating challenges. In particular, the A.B. Brown Units rely on scrubbers that utilize a technology that has been abandoned by the industry because of its high variable costs and the vapor it emits which causes corrosion of the unit structure. The scrubbers are already past their expected 30 year design life and present a significant risk to reliability and maintenance costs. He explained that Culley Unit 2 is Vectren South's oldest and smallest unit and that it has the worst heat rate of any coal unit in the state. Finally, he explained the unique circumstances related to the joint operation of the Warrick Unit which creates uncertainty as to the duration of its operation.

Ms. Angila Retherford, Vice President of Environmental Affairs and Corporate Sustainability, testified regarding two new major federal regulatory initiatives – Effluent Limitations Guidelines ("ELG") and Coal Combustion Residuals ("CCR") - impacting Vectren South's coal-generating units. Absent substantial investment at all of Vectren South's coal plants, they must cease operations by December 31, 2023. Ms. Retherford described Vectren South's environmental compliance strategy for the A.B. Brown and Culley units and testified future compliance costs were modeled in Vectren South's 2016 Integrated Resource Plan ("IRP") under the business as usual scenario. Ms. Retherford testified these rules and other existing federal regulatory requirements will require Vectren South to make significant further investment at the A.B. Brown and Culley generating facilities to continue their operation.

ii. Non-Utility Parties.

(1) OUCC. OUCC witnesses Lauren M. Aguilar – Utility Analyst, Anthony A. Alvarez – Utility Analyst and Peter M. Boerger – Senior Utility Analyst testified regarding Vectren South's request for a CPCN to construct the CCGT. These OUCC witnesses testified Vectren South's decision to construct the CCGT is premature because Vectren South has not explored all practical alternatives to extend the life of the A.B. Brown units. OUCC Witness Aguilar ultimately recommended that the decision to build the CCGT be delayed until the end of the 2019 IRP process, in order to allow Vectren South the opportunity to evaluate additional alternatives. The OUCC offered no alternative resource proposal, but argued for a "blended approach" with the possible continued use of existing assets, and suggested that the necessary expenditures to continue use of these assets could be viewed as buying an "option on the future." The OUCC witnesses asserted that deferring any decision until the conclusion of the 2019 IRP process would still allow sufficient time to take action without affecting reliability.

(2) Coal Parties. The Coal Parties' witnesses generally testified that Vectren South should wait to transition its baseload generation from coal to natural gas because the environmental regulations driving the transition, the ELG and CCR rules, are in flux and not yet final. Specifically, the Coal Parties' witnesses testified that recent and anticipated EPA reconsiderations of the ELG and CCR regulations, as well as the potential stay or replacement of the Clean Power Plan ("CPP"), create the potential scenario where Vectren South could operate the A.B. Brown and Culley units beyond 2023 without the need to make material investments in compliance measures. Coal Parties witness Michael J. Nasi – Partner with the law firm of Jackson Walker L.L.P. – further testified that Vectren South's decision to retire its coal plants is premature. He recommended that the decision be delayed until the environmental regulations driving the decision are better understood. With respect to the A.B. Brown units, the Coal Parties suggested that Vectren should investigate an alternative scrubber technology marketed by a Chinese firm to replace the existing dual alkali scrubbers. This technology which uses ammonia creates material that can be sold as fertilizer with revenues used to offset variable operating costs of the scrubber.

iii. Vectren South Rebuttal. Ms. Retherford, who is also a licensed attorney, testified regarding the risks associated with continuing to operate Vectren South's coal-fired fleet and delaying the decision to construct the proposed CCGT. Ms. Retherford testified that recent legal developments related to the CCR rule have made it impossible for Vectren South to continue operating its coal-fired fleet beyond 2023 without significant capital investment. She testified that the current water discharge permits require, and the groundwater monitoring results at the A.B. Brown and Culley ash ponds confirm, that Vectren South must cease discharging coal ash by December 31, 2023, pursuant to the ELG and CCR rules. She also testified that *Utility Solid Waste Activities Group v. Environmental Protection Agency*, 901 F.3d 414 (D.C. Cir. 2018), 2018 U.S. App. LEXIS 23547, confirms that the CCR Rule is final, including the final compliance deadlines at issue in this proceeding. Ms. Retherford testified that pond retirement delay is not an option, and therefore Vectren South must either make investments to comply with the CCR rule or retire the plants before 2024.

In response to the Coal Parties' position that the current administration could alleviate environmental carbon regulations applicable to the coal units, Ms. Retherford testified that the Administration's proposed replacement for CPP does not alleviate the problems. On August 31, 2018, the EPA published its proposed Affordable Clean Energy ("ACE") rule in lieu of CPP. She explained

that ACE would increase uncertainty and could actually increase the cost of compliance. For units with high heat rates – such as A.B. Brown – ACE would cause significant future compliance costs.

Vectren South also presented the testimony of Richard McMahon from Edison Electric Institute ("EEI") regarding the growing importance of Environmental, Sustainability and Governance ("ESG") reporting and metrics to the financial community, and the focus of all public electric utilities on being responsive to these topics and establishing explicit carbon reduction targets as part of their public disclosures. Mr. McMahon described the coordinated electric industry response to the demands for ESG reporting, and provided specific examples of lenders and large institutional investors who are putting pressure on companies to transition from dependence on coal units. He explained that Vectren South's 60% carbon emission reduction was in line with similar targets publicly disclosed by its electric utility peers. He also presented information regarding the industry transition from reliance on coal to use of gas as part of the ability to reduce carbon emissions.

As to the potential for alternative scrubbers, Vectren South witness Paul Farber – Principal of P. Farber & Associates, LLC – testified regarding the shortcomings of the technologies presented by Sunrise Coal witness Dombrowski and OUCC witness Aguilar and explained why, from an operational and financial perspective, it would not be prudent for Vectren South to adopt those technologies. With respect to the ammonia based scrubber technology presented by witness Dombrowski, Mr. Farber testified the technology has very limited deployment in the United States and would present a number of operational challenges if installed at baseload coal-fired units like A.B. Brown. These uncertainties and risks posed by adoption of this technology include its cost, its impact on operation of the units (including that it might cause Vectren South to be out of compliance with regulations for other constituents such as mercury and particulate matter absent further types of investments), the unknown ability to sell fertilizer output, and the complications associated with dealing with vendors with no domestic history. He discussed in depth the substantial operational burden and health and Homeland Security risk associated with handling the large amount of ammonia required by such a scrubber. Mr. Farber concluded that the Coal Parties had failed to provide any evidence that the capital costs of this scrubber technology would be any less than the scrubber modeled in Vectren South's 2017 IRP Update. In rebuttal testimony, Jon K. Luttrell, Senior Vice President, Utility Operations and President of Vectren Utility Holdings, Inc., also discussed the cyber security complications and risks posed by adoption of Chinese scrubber technology.

Mr. Farber also responded to OUCC witness Aguilar's criticism that Vectren South "only" evaluated wet limestone and her presentation of potential costs for other technologies. Mr. Farber testified that dry scrubbing is not an applicable technology at A.B. Brown for technical and economic reasons, and therefore it was logical for Vectren South to evaluate wet limestone technology at A.B. Brown. He also testified the cost estimates presented by Ms. Aguilar are not comparable cost estimates to replace the existing scrubbers at A.B. Brown Units 1 and 2.

Mr. Games testified on rebuttal that there simply is no time to delay a decision and await the outcome of another IRP. The Vectren South coal units must be retired or retrofitted by December 31, 2023. Given that there has been nothing to suggest more delay would change the overall economics that the F-class 2x1 CCGT is part of the lowest cost solution under every scenario, there is no reason to believe that modeling in the next IRP would change that result. Mr. Games provided an exhibit setting forth a timeline showing that a delay to allow the next IRP to proceed would leave Vectren South with essentially no baseload capacity for almost three years. During that entire period, Vectren

South customers would be completely exposed to the market for capacity and energy. Per the redirect examination of Justin M. Joiner, Director of Regulatory Policy and MISO Affairs for Vectren Utility Holdsings, Inc. ("VUHI"), this would be during the period when MISO is projecting its largest capacity shortfall for Zone 6 (Indiana). The Commission's Director's Report states "[a]n appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource." Mr. Games testified on cross-examination that Vectren South has waited as long as reasonably possible.

B. Modeling and Results. Only two parties presented modeling evidence and results. Vectren South presented the modeling from the 2017 IRP Update and the 2016 IRP. Sunrise Coal Witness Philip Hayet presented alternative modeling whereby Vectren South's Preferred Portfolio was delayed by seven years in order to allow existing coal units to continue to operate beyond 2023. Other parties offered criticism of Vectren South's modeling but presented no alternative modeling.

i. 2016 IRP. Vectren South's case was filed in the context of a proposed new rule to govern the IRP process. While our new rule was not effective during the 2016 IRPs, all participating electric utilities complied. This new process is significantly more transparent. It includes the participation of stakeholders, the convening of public meetings, and the submission of and response to comments. Mr. Matt Rice, Director – Research and Energy Technologies, testified regarding Vectren South's IRP process and the results of that process. Mr. Rice described Vectren's approach to its 2016 IRP process and testified Vectren South engaged several industry experts, including Burns & McDonnell and Pace Global, to conduct technical modeling. Mr. Rice testified Vectren South worked with these experts and IRP stakeholders to conduct scenario analysis to evaluate 15 portfolios, each representing a different mix of supply and demand side resources to meet customer load over a 20-year time horizon. He further testified Vectren South worked with Pace Global to conduct a risk analysis and evaluate the 15 portfolios using a balanced scorecard approach. From this analysis, Vectren South identified the "preferred portfolio" which consisted of replacing all existing coal fired generation other than Culley Unit 3 as well as gas peaking units Northeast 1 and 2 and Broadway 1 by 2024 with an F-class .05 Fired CCGT. Mr. Rice testified Vectren South incorporated stakeholder input throughout the process and described the steps Vectren South took to engage stakeholders both before and during the process. This engagement included having stakeholders develop two portfolios which were then modeled and included in the risk analysis.

Mr. Matthew Lind – Associate Project Manager, Burns & McDonnell – described the modeling Burns & McDonnell conducted in the 2016 IRP on behalf of Vectren South to evaluate its resource needs over the next 20 years. He testified the results of Burns & McDonnell's modeling identified a low-cost portfolio that ceased coal operations at Vectren South's coal fired facilities (A.B. Brown Units 1 and 2, F.B. Culley Units 2 and 3, and Warrick Unit 4) and replaced this capacity and energy with the combined cycle facility proposed here along with a simple cycle facility. Mr. Gary Vicinus – Managing Director for Utilities at Pace Global – described Pace Global's role in identifying and defining the objectives, metrics and risks in order to select the preferred portfolio among the many options. He testified Pace Global used a balanced scorecard approach to apply a risk analysis to a selection of portfolios ultimately to recommend a preferred portfolio. Mr. Vicinus further testified regarding revisions Pace Global made to its risk analysis and explained that, even with these revisions, the risk analysis indicated the preferred portfolio was the best approach.

Mr. Rice described the preferred portfolio and explained why it ranked the best on the balanced scorecard. He testified it performed the best because the portfolio is diversified as it contemplates keeping FB Culley 3 (a coal unit) and existing wind contracts, building a CCGT and introducing solar and continuing to offer energy efficiency. He further testified it is among the lower cost portfolios (within 4% of the predominantly gas lowest cost portfolio) and ultimately performed best overall when viewed across multiple measures on the balanced scorecard. Because the all-gas portfolio represented the lowest cost portfolio, it is the retention of Culley Unit 3 and the accelerated addition of the 50 MW solar project that increases the costs of the Preferred Portfolio over the lowest cost all-gas portfolio. Retention of coal and the addition of solar are essential to diversity.

ii. 2017 IRP Update. Mr. Lind testified Vectren South requested Burns & McDonnell to update the 2016 IRP modeling and the re-evaluated low-cost portfolio was consistent with the low-cost portfolio identified in the 2016 IRP. He explained that several modeling inputs were updated, including the capital cost for solar resources, variable production costs and revenue requirements for existing units, an assumed operation of Warrick Unit 4 through 2023, and updated cost assumptions for capacity, energy, natural gas, coal, and energy efficiency.

OUCC witness Peter Boerger testified regarding Vectren South's 2017 IRP Update economic modeling. Mr. Boerger testified that Vectren South's 2017 IRP Update did not adequately consider viable options for serving its customers—including making use of existing resources and adequately considering the addition of a smaller CCGT unit rather than the 2x1 unit being proposed. Mr. Boerger also testified Vectren South's modeling of the proposed CCGT understated its capital cost by $200 million, an error which disadvantaged other options in Vectren South's modeling. Mr. Boerger ultimately recommended Vectren South reevaluate its future needs and model additional alternatives.

CAC witness Tyler Comings – Senior Researcher at Applied Economics Clinic – testified on behalf of the Joint Intervenors. Mr. Comings criticized Vectren South's modeling, testifying it was too convoluted to yield a sufficiently transparent or credible result. He testified Vectren South used too many models in the selection of the preferred portfolio and that the use of many models created ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan. Mr. Comings ultimately recommended Vectren South's petition be denied because, in his view, Vectren South did not provide sufficient justification for its choice to build the CCGT and continue the operation of Culley 3.

Indiana Coal Council witness Emily Medine – Principal in the consulting firm of Energy Venture Analysis, Inc. – also testified regarding Vectren South's modeling. Witness Medine testified Vectren South should have fully updated its 2016 IRP analysis, including its scenario analysis, in order to confirm its preferred resource portfolio. She further testified that such an update should include a broader analysis (including sensitivity analyses) of the relevant assumptions and factors as of a time as close to Vectren South filing its Petition as possible. Ms. Medine attributed the decision to build a CCGT to financial motivations and also opined that approval of the CCGT might be a condition to closing the Vectren South merger transaction.[2] Ms. Medine recommended that Vectren South's Petition be rejected because Vectren South has failed to show that proceeding with building the CCGT at this time is prudent, less risky, and a better decision for both customers and the environment.

[2] While this case was pending, it was announced publicly that Vectren South's holding company was the subject of an acquisition at the holding company level, which was the subject of Cause No. 45109.

Mr. Lind responded to Mr. Boerger's testimony about an alleged $200 million "error." He explained that approximately $67 million of the alleged error identified by Mr. Boerger was due to Mr. Boerger's mistaken assumption about whether modeled option costs are stated in 2017 dollars or nominal dollars in the year of incurrence. The remainder is due to Mr. Boerger's efforts to compare apples and oranges. As Mr. Lind explained, the modeling was done prior to the more refined cost estimates for the CCGT that were developed for this case. Rather than based on a design level accuracy of plus/minus 50%, the CCGT design has been refined to a plus/minus 10%. All of the other portfolios were still at plus/minus 50%. As Mr. Lind explained, to compare the other less refined portfolios to the more refined CCGT would require some additional risk factor for the other portfolios. But even if one includes the updated cost estimate, Mr. Lind testified that it doesn't change that the lowest cost portfolios still include the CCGT. Mr. Lind prepared additional modeling involving coal-to-gas conversion (which we will describe later) and which did include the more refined CCGT cost estimate. While this additional modeling used the more precise CCGT cost and therefore impacted every portfolio that included the CCGT by increasing the overall net present value ("NPV") by $54 million, the portfolios that included the CCGT were still the lowest cost portfolios compared to portfolios that did not include the CCGT. Regarding the use of the models, witnesses Lind and Vicinus confirmed that the process and modeling for Vectren South's IRP and risk analysis were consistent with the resource planning approach Pace and Burns & McDonnell have used for numerous other utilities.

(iii) Size of the Proposed CCGT. Joint Intervenors' witness Tyler Comings testified regarding the size of the proposed CCGT. Witness Comings testified that Vectren South has not provided a sufficient justification to build a CCGT of the size included in its proposal. Witness Comings also criticized Vectren South's Request for Proposals ("RFP") (which we will describe in greater detail later) which sought resources between 600 and 800 MW, because he believed Vectren South could have considered combinations of small resources that added up to 600 MW. He further testified that considering smaller options would limit the market risk exposure for ratepayers, as well as permit a combination of bids to make up a least cost alternative. Mr. Comings testified that in order to reduce ratepayers' risk, Vectren South should explore cost effective alternatives that do not require intensive capitalization, but still provide benefits to ratepayers.

OUCC witness Anthony Alvarez also testified regarding the size Vectren South is proposing for the CCGT. Mr. Alvarez testified that Vectren South currently has excess supply, and there is no resource shortfall or inadequacy that supports Vectren's proposed 850 MW CCGT. He also questioned the load forecast used in the IRP and testified Vectren South has excess supply after serving its peak load and therefore has excess capacity to offer into the market and serve new customers.

Industrial Group witness Michael Gorman also testified regarding the size of Vectren South's proposed CCGT. Mr. Gorman testified Vectren South's proposal to build an 850 MW CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases the costs of new generation resources and results in unrecovered stranded costs from the retired resources. Mr. Gorman recommended the Commission implement mitigation measures to reduce the cost burden on customers related to stranded costs and the cost of the new CCGT. He also recommended the Commission modify the off-system sales margin treatment so that 100% of future wholesale revenues be provided to customers to offset the cost of the proposed resource plan.

Vectren South witness Carl Chapman testified on rebuttal regarding Vectren South's decision to construct an 850 MW CCGT. Mr. Chapman explained the CCGT is essentially two units -- a 700 MW baseload unit to replace 730 MWs of retiring coal unit capacity and 150 MWs of duct fired peaking capacity to replace older peaking units and provide available low cost capacity for growth and wholesale sales opportunity. The additional peaking capacity is provided by the decision to duct-fire the CCGT. The incremental cost of duct-firing the CCGT is $15 million, and that decision must be made at the time the CCGT is constructed (i.e., it cannot be added at a later time.) Mr. Chapman testified that if only the unfired 700 MW baseload CCGT is built, then by 2025, Vectren South has a projected surplus above MISO's Planning Reserve Margin ("PRM") (which fluctuates) of only 51 MW. He further testified that by 2030, the surplus is only 5 MWs and by 2031 Vectren South will fail to meet its PRM. He testified that by 2036, Vectren South will be short 39 MWs, and all of this assumes Vectren South will not add significant new load. Mr. Chapman testified that with its low capital cost, firing makes sense from a customer perspective. For an incremental cost of 2%, the firing provides a 21% increase in capacity. Nevertheless, if the Commission approves the baseload 700 MW CCGT without firing, Vectren South will proceed to construct the unfired CCGT to replace its baseload coal units. He stated that Vectren South would also consider investing the incremental $15 million to duct-fire the unit and be at risk to recoup its investment via retention of the wholesale revenue produced by that peaking capacity.

Mr. Chapman also testified regarding Industrial Group witness Gorman's recommendation that Vectren South pass off-system sales margins on to retail customers. Mr. Chapman testified that Vectren South has decided to commit to provide 100% of wholesale sales revenue from the CCGT (baseload and peaking) to customers. Mr. Chapman explained that once the CCGT is placed in rate base, the benefits from the wholesale revenue produced by the unit will go to reduce customer costs. Mr. Chapman testified that providing 100% of wholesale revenue to customers further improves the NPV of the CCGT, will provide a larger offset to customer costs in general, and adds even more support to the $15 million incremental investment to duct fire the unit.

C. <u>Coal Parties' Modeling</u>. Indiana Coal Council, Inc. witness Philip Hayet – Vice President of J. Kennedy and Associates, Inc. – testified regarding Vectren South's 2016 IRP modeling and the 2017 IRP Update. Mr. Hayet testified that Vectren South's modeling analyses were flawed due to errors, inconsistencies, and a lack of consideration of important factors. Mr. Hayet performed his own analysis and testified that using the same model with certain corrections, including a deferral of a decision to add a CCGT, produced a slightly lower cost result on a NPV basis. He predicated his modeling on the assumption that the A.B. Brown 2 scrubber will continue to operate reliably through 2030. He ultimately recommended that Vectren South defer its decision to construct the CCGT.

On rebuttal, Vectren South witness Matthew Lind testified regarding Indiana Coal Council witness Hayet's alternative modeling. Mr. Lind testified that when Mr. Hayet's modeling is corrected for obvious errors, it reaches the same preferred portfolio conclusion as Vectren South's modeling. Mr. Lind provided corrections to Mr. Hayet's modeling in the form of an updated Strategist model and spreadsheets documenting the corrections. Mr. Lind outlined each of the errors he identified in Mr. Hayet's modeling and the impact of the individual errors on his analysis. The first of several errors he identified was that Mr. Hayet failed to include cost escalation during the seven years of delay that he was urging and that correcting this error alone would change Mr. Hayet's overall conclusion that delay would be less costly. Mr. Lind also testified regarding the cumulative effect of

addressing all of the errors. As part of this analysis, Mr. Lind testified that he included the increased cost of the CCGT to reflect the more recent cost estimates based on a plus or minus 10% confidence level. He testified that when correcting Mr. Hayet's modeling for all of these errors and inconsistencies, the NPV favors Vectren South's preferred portfolio, even under Mr. Hayet's no carbon regulation scenario. Witness Hayet corrected his testimony after Mr. Lind filed his rebuttal to add the escalation during the period of delay he was urging, and this correction changed his original conclusion that delay was less expensive. Mr. Hayet did not address the other modeling issues raised by Mr. Lind.

Mr. Games' rebuttal testimony also addressed witness Hayet's assumption that the A.B. Brown 2 unit and scrubber could be operated without added cost and reliability risk through 2030. Apart from the reliability issues created by the frequent cycling of the unit, he explained the structural damage resulting from the corrosive environment created by the unique characteristics of these scrubbers, and based on his direct experience with this equipment, Mr. Games concluded that he could not agree that it would be prudent to continue to operate the A.B. Brown 2 scrubber for another 12 years beyond 2018.

D. Renewables and All-Source RFP. Joint Intervenor witness Tyler Comings criticized the costs assumed in Vectren South's modeling for most renewable energy sources. Mr. Comings testified that Vectren South's forecast of the capital costs of future wind resources is higher than he would have recommended for the type of planning analysis and its forecast of the fixed O&M costs are lower. Mr. Comings recommended the use of the National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") to develop the forecasts. With respect to future solar resources, Mr. Comings testified Vectren South's forecasts are too high for both the capital and fixed O&M costs. Mr. Comings recommended the reliance on the ATB to develop wind and solar price forecasts. For utility-scale PV, he testified that the ATB midpoint projection would be appropriate. As part of his discussion of renewable costs, he noted that Northern Indiana Public Service Company ("NIPSCO") had recently conducted an RFP and obtained solar and wind bids. Mr. Comings testified that Vectren South's overestimation of renewable costs compared to the ATB data biased the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

On rebuttal, Mr. Lind responded to Mr. Comings' testimony related to the cost of renewables included in Vectren South's modeling. With respect to wind resources, Mr. Lind noted that prior to revising his testimony, Mr. Comings' originally filed testimony included an inaccurate and inappropriate comparison of assumed capital cost for wind resources between Vectren South and ATB because Mr. Comings failed to account for the declining cost curve over time utilized by Vectren South. Mr. Lind testified that when Mr. Comings updated his testimony to reflect this decline, he recognized that Vectren South's wind costs are only "slightly higher" than what Mr. Comings recommends. Mr. Lind further testified that even with this correction, Mr. Comings' comparison to the ATB figures is incorrect because the ATB figure excludes a 2.1% construction finance factor and is thus understated. Mr. Lind testified that when the 2.1% construction finance factor is included, the ATB capital cost will exceed Vectren South's modeled capital cost for wind over more than half of the planning period. Mr. Lind pointed out that Vectren South assumed a higher capacity factor than the ATB survey and also assumed lower O&M costs compared to the ATB survey, and as a result, it is likely that the wind prices recommended by Mr. Comings are actually higher than those modeled by Vectren South.

With respect to Mr. Comings' criticisms of Vectren South's solar costs, Mr. Lind testified Mr. Comings again failed to account for the declining cost curve over time in the original version of his testimony. Mr. Lind further testified that while Mr. Comings did update his comparison to reflect the decline, he did not update it to include the 2.1% construction finance factor in the ATB comparison. Moreover, Mr. Lind explained that the national survey costs relied upon by Mr. Comings were presented on a direct current (DC) basis, whereas the 2017 IRP Update stated cost in terms of alternating current (AC), thus requiring that Comings' costs be converted to AC to allow for a valid comparison to be made. When correcting for these additional errors, Mr. Lind testified the solar costs used by Mr. Comings and Vectren South are nearly consistent over the last half of the study period and fairly similar from 2024 onward, which is the point at which capacity is needed.

Mr. Lind also testified regarding the impact of network upgrades and congestion costs on a portfolio that would rely more heavily on renewables. Mr. Lind testified that a portfolio which would rely heavily on renewables to supply power to Vectren South's customers is more likely to source some or all of these resources remote to Vectren South's service territory given the acreage required for such projects, the grid issues that can be encountered, and the enhanced production that can be obtained in certain locations (e.g., northern Indiana). Mr. Lind explained that when significant amounts of power are sourced from off-system resources, congestion costs to Vectren South's customers increase substantially. Because such costs were not part of the 2017 IRP Update assumptions, Mr. Lind concluded that any small differences between the solar costs presented by Mr. Comings and those modeled by Vectren South would be more than offset by the congestion costs associated with greater reliance on such resources. Finally, Mr. Lind noted that even assuming lower renewable costs could be achieved, such resources would likely displace Culley Unit 3's 270 MWs of capacity because that could be done incrementally to reduce the effects of network upgrades and congestion, whereas the CCGT would remain the optimal low cost choice to replace the remaining 730 MWs of retiring coal capacity in 2023. Further, wind and solar are intermittent sources of power; given that Culley Unit 3 would be Vectren South's only baseload capacity under its preferred portfolio, dispatchable baseload generation from a CCGT provides greater flexibility to respond to intermittent resources.

E. Capacity Price Forecasts. Mr. Comings testified regarding Vectren South's ability to purchase future needed capacity from the MISO market. Mr. Comings testified that Vectren South overestimated future capacity prices in MISO in its modeling, and in reality, the MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. He testified Vectren South's assumption of higher capacity prices is critical, because it makes the economics of building a new resource more attractive. He concluded that Vectren South was placing risk on its customers if the price of capacity is lower. To reach his conclusion, he relied on the MISO auction clearing results for Zone 6 (Indiana) for the past five years. Indiana Coal Council witness Hayet had a similar criticism of Vectren South's modeled capacity prices. He agreed that the cost of new entry ("CONE") served as the upper end of future capacity prices but that, also based on MISO historic auction clearing prices, it was inappropriate for future assumed capacity prices to approximate CONE. Instead, witness Hayet proposed to use 75% of CONE.

On rebuttal, Vectren South witness Joiner responded to Mr. Comings' testimony related to Vectren South's alleged overestimation of MISO capacity prices. Mr. Joiner testified he disagreed with Mr. Comings' contention that Vectren South should assume it will be able to purchase capacity and energy from the MISO market at low prices based upon recent market conditions. Mr. Joiner explained that the MISO market has been volatile in recent years and is experiencing shrinking

capacity, and such factors have prompted MISO to evaluate changes to its market structure. Mr. Joiner testified that MISO's recent and pending market reform initiatives, including MISO's Resource Availability and Need ("RAN"), are aimed at increasing capacity and energy prices to incentivize new generation development and are thus leading to higher prices as capacity tightens. As such, Mr. Joiner testified that while MISO's historical capacity and energy prices are indicators of recent trends, contrary to Mr. Comings' MISO auction clearing price testimony, they are not good indicators of expected, long-term future pricing. Moreover, the reported potential for a capacity shortfall by 2024 shows the risk of increased market prices.

F. Refueling Options. OUCC witness Boerger recommended that Vectren model a smaller 440 MW CCGT option in conjunction with gas refueling of one or both A.B. Brown units in order to consider a lower capital cost alternative. This option, which replaces retired coal units with a smaller gas baseload unit, was consistent with his stated concern that implementation of large quantities of intermittent renewables could create grid difficulties and that the extension of the life of small coal units is not common in the industry.

Mr. Lind's rebuttal presented the results of additional modeling in response to the OUCC's interest in further analysis related to resource plan options including coal-to-gas conversion that would make use of the A.B. Brown unit boilers. Burns & McDonnell performed that modeling and analyzed four additional portfolios, each where the conversion of one or more units to natural gas was considered. Mr. Lind testified that this updated rebuttal modeling used the more refined cost estimates (at the plus/minus 10% confidence level) for the CCGT for comparison with the coal-to-gas conversion portfolios (which were stated at plus/minus 50% accuracy.) Mr. Lind described the results of the updated analysis and testified that when compared with the coal-to-gas conversion portfolios, the preferred portfolio still produces a lower NPV and projected customer cost. Witness Games explained that this is due in part to the high heat rates of refueled units which result in very poor dispatch rates and resulting reliance on the market for energy needs. He explained that such a portfolio would result in customers significantly depending on market purchases for energy. Witness Games testified the fuel cost per MWhr from a converted gas plant is roughly $20 more expensive than the cost from the proposed CCGT when gas price is $4.000/dkt. He showed the much higher heat rates and lower capacity factors at converted plants that were completed between 2013 through the first quarter of 2018. Mr. Games testified during the hearing that the problem of high heat rates means that the refueled units continue to cycle and ramp up and down when dispatched, leading to wear and tear and the risk of additional maintenance costs.

G. Docket Entry Question & Response. As a follow-up to the additional modeling performed by Vectren South on rebuttal of gas conversion options, we issued a Docket Entry requesting further iterations of gas conversion portfolios. These included refurbishment of Broadway Unit 2 coupled with delays of removal of Warrick Unit 4 and installation of either a simple cycle or combined cycle gas turbine. Vectren South's response included the more refined cost estimate of the CCGT at plus/minus 10%, excluded additional environmental compliance costs at Warrick Unit 4 that would allow for the delay, and were presented with and without the commitment by Vectren South on rebuttal to pass 100% of wholesale revenues to customers if the CCGT is approved. All of the additional modeling requested by our docket entry produced a higher NPV than the lowest cost refueling portfolio presented on rebuttal (to convert A.B. Brown and instill a simple cycle gas turbine). With the sharing of 100% of wholesale revenues, all of the additional modeling produced a higher NPV when compared to the preferred portfolio ranging from 3.5% to 7.0%. Given that the preferred portfolio was within 4% of the lowest cost 2016 IRP portfolio (CCGT, an additional

simple cycle turbine, and delayed renewables), that means the gas conversion portfolios ranged anywhere from 8-12% higher than the lowest cost portfolio.

H. Estimated Cost of CCGT and RFP Process.

i. Vectren South. Mr. Games testified that, consistent with the 2016 IRP results, the 2017 IRP Update, and the Pace risk analysis, Vectren South is proposing to build a CCGT with 700 MW of baseload capacity and 150 MW of peaking capacity to replace retiring coal-fired capacity. Mr. Games testified Vectren South is proposing to build a unit with an output of approximately 850 MWs in order to hold some additional capacity to meet its obligations as a public utility, as well as to serve potential new customers and foster economic development. The 850 MW replaces 865 MW of retiring capacity (730 MW of baseload and 135 MW of peaking capacity, including Broadway Unit 2 in 2025). Mr. Games further testified the estimated cost of the CCGT is $781 million (+/-10%). The estimate includes owner's costs and allowance for funds used during construction ("AFUDC"). This figure was based on cost estimates developed by witness Diane M. Fischer, Central Regional Area Director and Associate Vice President with Black & Veatch. Those estimates were derived from a request for proposals for all equipment comprising the CCGT as well as construction. Mr. Games testified Vectren South is proposing to construct the new CCGT on its existing A.B. Brown generating site which will provide a conservative cost savings of $50 million resulting from reusing the existing site, facilities and equipment. He explained the critical timing of the in-service date of the CCGT which will be operational for the 2023/2024 MISO capacity year in order to retire the Culley 2 and A.B. Brown units and thereby avoid material capital investments otherwise required to operate those units beyond 2023. Similarly, the Warrick Unit 4 joint operating agreement will terminate at the end of 2023. To continue to operate Warrick would also require further investment to comply with environmental regulations.

Mr. Luttrell testified regarding the other replacement generation options Vectren South considered. He described the solicitation of competitive bids for either purchased power or ownership of all or a portion of a new CCGT unit. Mr. Luttrell explained Vectren South engaged Burns & McDonnell to manage the entire power supply RFP process, and testified this process allowed Vectren South to compare the best competitive offers for dispatchable baseload capacity to several self-build alternatives, including a partnership alternative. Mr. Luttrell testified that based on this economic and qualitative comparison, Vectren South made the decision to pursue building the duct-fired version of the proposed CCGT at the existing A.B. Brown site.

Mr. Lind testified in greater depth regarding Burns & McDonnell's role in developing and managing the RFP process to address Vectren South's power supply needs. He testified Vectren South received 11 unique proposals from six different developers. He further testified each of the conforming proposals was ranked and the top two proposals were compared with Vectren South's self-build proposals. Mr. Lind testified that based on NPV cost and qualitative risk factors, including a congestion analysis related to an off-system generation project developed by a third party, Vectren South determined that the self-build option was the best resource for reliable, long term service.

ii. OUCC. Witness Alvarez testified that, while Vectren South conducted an RFP, Vectren South did not competitively bid the actual CCGT it seeks to build in this case. OUCC witness Aguilar testified that Vectren South has not yet identified a manufacturer, chosen an exact type of CCGT, or issued any bids for the project.

iii. Coal Parties. ICC witness Medine criticized Vectren South's RFP process for a number of reasons, including the contention that Vectren South was involved in the process and the self-build project did not submit a bid as part of the RFP process. ICC witness Hayet stated a similar concern. Ms. Medine also disagreed with the position that self-build projects represent less risk than merchant projects. Ms. Medine further testified regarding the risks associated with self-builds, including cost over-runs. She testified that most if not all new Indiana plants have experienced cost over-runs that utilities look to customers to recover, and unless Vectren South is willing to guarantee costs, this is a risk that should be considered.

iv. Joint Intervenors. Witness Comings testified Vectren South did not facilitate a competitive bidding process, which limited resources and discouraged bidders from offering purchased power agreements ("PPAs"). He further testified the RFP should not have been limited to MISO Zone 6 and should have been similar to other investor-owned utility solicitations.

v. Vectren South Rebuttal. Mr. Luttrell responded to the Intervenors' criticisms of Vectren South's RFP process. With respect to Mr. Comings' criticisms that Vectren South did not facilitate a competitive bidding process, including limiting resources and discouraging bidders from offering PPAs, Mr. Luttrell testified Vectren South is retiring over 70% of its baseload capacity and the RFP was specifically designed to fill that deficiency with reliable cost-effective supply identified by the IRP. Mr. Luttrell further testified PPAs were not discouraged and all four of the responsive bidders offered a PPA. Mr. Luttrell also responded to Ms. Medine's criticisms that Vectren South was involved in many aspects of the solicitation and that Vectren South did not submit a bid as part of the RFP Process. Mr. Luttrell testified Vectren South used two separate teams—one focused on the RFP and evaluation and one focused on developing the cost estimate for the Vectren South-build CCGT—and each of these teams were separate and walled off from the other. He testified Vectren South's involvement in the RFP process was critical to help ensure the RFP would meet the needs its modeling indicated was necessary. He further testified he did not believe the RFP process was negatively impacted as a result of the self-build alternative being developed parallel to the evaluation of the RFP bids, and Ms. Medine acknowledges "there is no evidence that there was inappropriate information transfer." Mr. Luttrell explained that ultimately, an evaluation of congestion costs associated with the off-system resource proposal was the driver of selecting the CCGT project at A.B. Brown as the best option.

Mr. Luttrell also responded to Ms. Medine's position that a PPA does not pose a greater risk than having a regulated utility own the generation facility. Mr. Luttrell testified that Vectren South believes that an on-system project at an existing utility site subject to regulatory oversight and financed by a public utility, is less risky than relying on a developer. He further testified that when 70% of baseload capacity is at stake, a utility should consider all risks to project completion and to ongoing service in the long term. Mr. Luttrell provided a real-life, recent example of the risks associated with relying on a developer to construct a project. Further, Mr. Luttrell testified that a PPA does represent greater risk compared to a self-build option because the financing, construction, operation, and future financial stability of the seller is not in control of either the regulated public utility or the Commission. Mr. Lind also explained that while the cost estimate for the CCGT is stated at plus/minus 10%, the risk is actually higher (plus/minus 50%) for all portfolios that do not include the CCGT.

I. Construction of Gas Lateral to Serve CCGT.

i. Vectren South. Mr. Perry Pergola – Director, Gas Supply – testified regarding Vectren South's decision to secure the interstate pipeline services of Texas Gas Transmission ("TGT") to provide natural gas service to the proposed CCGT. He testified Vectren South selected TGT because it was the least cost pipeline option to serve the CCGT at the A.B. Brown location. Mr. Pergola further testified Vectren South will build and operate a new gas lateral to interconnect with TGT and serve the CCGT.

Mr. Steve Hoover – Director of Engineering – testified regarding the 23 mile gas lateral Vectren South will construct to connect the CCGT with TGT. He testified Vectren South will construct the pipeline itself because, by virtue of its experience building, operating and maintaining new or existing gas facilities in the Vectren South service area, Vectren South is uniquely qualified and positioned to construct the new pipeline. Mr. Hoover further testified the estimated cost to construct the gas pipeline is approximately $87 million. This is not included in the estimated cost of the CCGT as presented by witnesses Fischer and Games, as it is expected the costs of the gas pipeline will be reflected in the delivered cost of the gas.

ii. OUCC. OUCC witness Alvarez testified regarding Vectren South's proposal to build the gas lateral to serve the CCGT. He testified Vectren South did not include the costs necessary to build the gas lateral in the $781 million CCGT cost estimate and should have.

iii. Industrial Group. Industrial Group witness Gorman also testified regarding Vectren South's proposal to construct a gas lateral to serve the proposed CCGT. Mr. Gorman testified Vectren South's proposal to self-build the gas lateral is not consistent with protecting the public interest and is anti-competitive. He testified that Vectren South should have considered a third party or TGT to develop the gas lateral. Mr. Gorman testified that to the extent TGT can construct a gas lateral at a lower cost than the Vectren South self-build option, then this option should be adopted. Mr. Gorman further testified that Vectren South's proposal to recover the pipeline costs as part of the fuel costs for the CCGT is not reasonable because the fixed cost to build the gas lateral will not vary with energy generation or volume of gas delivered to the CCGT. He testified instead it would be appropriate to allocate the gas lateral cost as part of the CCGT fixed capital cost of the facility and allocate it on a capacity basis.

iv. Coal Parties. ICC witness Medine testified regarding Vectren South's proposal to construct the gas lateral. Ms. Medine characterized Vectren South's proposal as a proposal to build the lateral using an affiliate without competitive bidding. She also criticized Vectren South's decision to self-build the gas lateral instead of soliciting bids from third parties. Ms. Medine testified that Vectren South did not solicit bids for the lateral from third parties, and, therefore, it cannot represent that it was the lowest cost option for the construction of the lateral.

v. Vectren South Rebuttal. Vectren South witness Steve Hoover responded to criticisms raised by the Intervenors related to Vectren South's proposal to construct the gas lateral. Mr. Hoover testified that Ms. Medine's characterization of the proposal as an "affiliate transaction" has no bearing on the overall substance of the proposed transaction because there are many reasons why it is advantageous for Vectren South to construct the gas lateral. He reiterated that the Vectren South engineering, land services, and construction management teams have already

successfully completed two similar projects to deliver gas to Duke Edwardsport and IPL Eagle Valley generating units. He testified it is therefore in the best interest of Vectren South's customers for it to enlist the experience and expertise of its gas utility in the pipeline construction and operations. Mr. Hoover also responded to criticisms raised by witnesses Gorman and Medine that the lateral project is anti-competitive and being conducted without competitive bidding. Mr. Hoover testified that Vectren South requested TGT to provide a cost estimate to construct the lateral early in the process, and TGT's cost estimate was 10-15% higher than Vectren South's estimate. He further testified that Vectren South will complete a competitive procurement process to select a contractor to construct the lateral. Mr. Hoover testified that during the course of bidding and the evaluation process, Vectren South will also incorporate cost protections and performance incentives to ensure both competitive and fair pricing.

Mr. Hoover also responded to Mr. Gorman's preference that the lateral be placed in Vectren South's rate base as opposed to the costs being recovered via the Fuel Adjustment Clause ("FAC"). Mr. Hoover testified that like IPL and Duke, Vectren South has chosen to have a qualified local distribution company ("LDC") own and operate its gas delivery pipeline. Therefore, the pipeline will not be an electric utility asset and the costs associated with it will be recovered through gas rates.

As to the allegation that Vectren South's owning the gas pipeline as a gas utility asset is anti-competitive, witness Pergola testified on cross-examination that nearly all of the pipeline (more than 22 of the 23 miles of length) is located in Kentucky and therefore presents no opportunity for bypass, because Vectren South does not possess the right to serve customers in Kentucky.

J. Warrick Unit 4.

i. Vectren South. Mr. Wayne Games testified regarding the uncertain future of Warrick Unit 4. Mr. Games explained that Vectren South and Alcoa co-own the unit pursuant to a Joint Operating Agreement ("JOA") whereby each has 50% ownership in the unit. Mr. Games testified that while Warrick Unit 4 will continue to operate in the near term, the long term outlook for the unit is uncertain. He testified the future of the unit is tied to the Alcoa industrial site, and at any time Alcoa could decide to close the smelter unit, which utilizes significant quantities of electricity produced by Warrick Unit 4, based on price volatility in the aluminum market. He testified that the decision to shut down the smelter unit would jeopardize the future of Warrick Unit 4 and this uncertainty makes it difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South witness Carl Chapman also testified regarding the future of Warrick Unit 4. Mr. Chapman testified that Vectren South has agreed to retain its involvement in the unit through 2023 to support the re-opening of the Alcoa smelter. However, he testified beyond 2023 it does not makes sense to continue to invest in a unit that could be subject to shut down if Alcoa decides it has no continuing need for the capacity.

ii. OUCC. OUCC witness Aguilar testified regarding Warrick Unit 4. Ms. Aguilar testified she does not agree with Vectren South's assessments of the risk of continuing to operate Warrick Unit 4 under the JOA and she disagrees with Vectren South's "presentation of the agreement." She further testified that Vectren South could continue to operate Warrick Unit 4 beyond 2023 with environmental compliance updates.

iii. Vectren South Rebuttal. Mr. Games responded to OUCC witness Aguilar's contention that Vectren South could continue to operate Warrick Unit 4 beyond 2023. He testified that due to compliance requirements coming in Alcoa's next National Pollutant Discharge Elimination System ("NPDES") permit, it is anticipated that the unit will require significant capital investment to meet environmental standards in the future. He testified that these investments coupled with the uncertainty related to whether Alcoa will continue to operate Warrick Unit 4[3] under the JOA and performance issues at the unit, warn against continued reliance on Warrick Unit 4.

Mr. Chapman also testified regarding the continued operation of Warrick Unit 4. He testified that the partnership with Alcoa jointly to operate Warrick Unit 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option. Mr. Chapman further testified that while Vectren South's IRP recommended retirement of Warrick Unit 4 well before 2023, Vectren South examined each of the coal units to determine whether such units should be retained. He testified that while Culley 3 and Warrick Unit 4 had better profiles in terms of environmental equipment as compared to Vectren South's other units, Culley 3 ultimately had a better operating history based on cost, availability and heat rate. Mr. Chapman reiterated that a strike against continued operation of Warrick Unit 4 is the uncertainty surrounding the longevity of the Alcoa partnership. He reiterated the continued operation of Warrick Unit 4 is dependent on the aluminum market, and if Alcoa's industrial operations cease at the site, the environmental requirements facing Warrick Unit 4 will become significantly more stringent. Mr. Chapman ultimately testified the bottom line is assuming Warrick Unit 4 can continue on post-2023 presents great risk.

As noted previously, in response to our Docket Entry question seeking additional modeling of a portfolio with delayed retirement of Warrick Unit 4, Vectren South indicated that an additional capital investment cost of as much as $50 million may be required to retain the unit if IDEM determines not to renew a variance in the unit's current NPDES permit that allows water discharge at a higher temperature. The new draft renewal NPDES permit allows IDEM to terminate this variance at any time, which will likely require the construction of a cooling tower. Coupled with both Alcoa's and Vectren South's ability to terminate the joint operating agreement, this even further increases the risk of reliance on Warrick Unit 4 beyond 2023.

K. Culley Unit 3. While making investments to preserve some coal-fired generation is not part of the lowest NPV under the 2016 IRP modeling, Vectren South proposes to make investments at Culley Unit 3, its most efficient plant, in order that it may continue to operate beyond 2023. This decision became part of the preferred portfolio as a result of the risk assessment in the 2016 IRP. Preserving Culley Unit 3 promotes greater diversity in fuel sources and it also lessens the impact on the local coal industry. Witness Retherford described the environmental controls that are needed as a result of CCR and ELG. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. Witness Fischer developed the cost estimates for the former two and Ms. Retherford provided the cost estimate for the latter. Recovery of the associated costs through a rate adjustment mechanism under Ind. Code ch. 8-1-8.4 was opposed by OUCC witness Aguilar and Industrial Group witness Gorman.

[3] With proper notice, Alcoa can also terminate the JOA.

4. Pending Summary Judgment Motion and Motion to Dismiss under T.R. 41(B). On July 19, 2018, the Coal Parties, Joint Intervenors, Evansville Western Railway, the OUCC, and the Industrial Group filed a Motion for Summary Judgment asking the Commission to vacate the schedule, arguing that we cannot grant Vectren South's request for authority to construct facilities until we have completed a "final" statewide analysis pursuant to Ind. Code § 8-1-8.5-3(a). Alternatively, the Movants asked us to grant them an extension of time to file their pre-filed testimony until at least 45 days after we post a "final" statewide analysis. We took the matter under advisement. At the conclusion of Vectren South's case-in-chief, Alliance Coal made an oral motion to dismiss under T.R. 41(B) on the same grounds. The T.R. 41(B) motion was joined by the OUCC and all of the other Movants except the Industrial Group and Evansville Railway.

In construing a statute, we start with its plain language and "attempt[] to give words their plain and ordinary meanings." *Indiana Wholesale Wine & Liquor Co., Inc. v. State ex rel. Indiana Alcoholic Beverage Com'n*, 695 N.E.2d 99, 103 (Ind., 1998) (citations omitted). "[I]n seeking to give effect to the legislature's intent, [the court] read[s] an act's sections as a whole and strive[s] to give effect to all of the provisions so that no part is held meaningless if it can be reconciled with the rest of the statute." *Fort Wayne Patrolmen's Benev. Ass'n, Inc. v. City of Fort Wayne*, 903 N.E.2d 493, 497 (Ind. Ct. App., 2009) (citation omitted).

The Motion is based primarily on Section 3(a) of Ind. Code § 8-1-8.5, which provides that "[t]he Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion of facilities for generation of electricity," and Section 3(c), which provides that "[t]he commission shall consider the analysis in acting upon any petition by any utility for consideration." The Movants interpret these provisions to mean that we cannot consider a certificate of public convenience and necessity ("CPCN") request absent a "final" statewide analysis. We disagree.

Neither provision requires or implies there must be a "final" or conclusive statewide analysis. Nor does any other provision in Chapter 8.5. Section 3 directs us to undertake an "analysis" that is subject to ongoing review and revision. An analysis that must remain "current" cannot possibly remain static or culminate in a finished product. We find that the analysis detailed in the draft and final versions of the Statewide Analysis meets the requirements of the statute.

To the extent the Movants argue that we cannot grant Vectren South's Petition until we complete our annual report on the analysis, their Motion also fails.

Section 3(h) requires us "[e]ach year" to "submit to the governor and to the appropriate committees of the general assembly a report of its analysis regarding the future requirements of electricity for Indiana or this region." Ind. Code § 8-1-8.5-3(h). Section 5(b)(2) provides that a certificate may be granted if the Commission finds the project (A) "will be consistent with the Commission's analysis (or such part of the analysis as may then be developed, if any)"; or (B) is "consistent with a utility's specific proposal submitted under Section 3(e)(1) of this chapter and approved under subsection (d)." Ind. Code § 8-1-8.5-5(b)(2)(A) and (B).

This unambiguous language reflects the Legislature's understanding that new generation needs may arise at a time while the analysis or even the annual report is being developed or under revision. The Legislature granted the Commission authority to issue a CPCN rather than hold the request in abeyance until the annual report is issued.

It must be presumed that "'the legislature intended the language used in the statute be applied logically and not to bring about an unjust or absurd result.'" *D.B. v. Review Bd. of Indiana Dept. of Workforce Development*, 2 N.E.3d 705, 710 (Ind. Ct. App., 2013) (quoting *Penny v. Review Bd. of Ind. Dep't of Workforce Dev.*, 852 N.E.2d 954, 960 (Ind. Ct. App., 2006), trans. denied). Reviewing bodies also avoid "interpreting a statute in such a manner as to render its provisions mere surplusage." *Id.* (citing *In re Adoption of D.C.*, 887 N.E.2d 950, 959 (Ind. Ct. App., 2008). The Legislature cannot have meant for the Commission to hold off assessing petitions until its analysis becomes "final" (which will never occur), or even until its annual report is submitted. Thus, the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on whatever current statewide analysis exists or simply determine whether the proposal is consistent with the utility's own plan and reports.

In sum, the Commission retains authority to review a project at any time. Ind. Code § 8-1-8.5-5.5 expressly allows us to "commence a review of any certificate granted under this chapter" when, "in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity" call for such review. Further, "[i]f the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate." Id.

For all of the foregoing reasons, and each of them, the Motions for Summary Judgment and for Dismissal under T.R. 41(B) are denied.

5. Commission Discussion and Findings.

A. Vectren South's Request for a CPCN for a CCGT. Vectren South requests a CPCN for a proposed CCGT (approximately 850 MW) to be constructed at the current site of the A.B. Brown power plant in Posey County. Under Chapter 8.5, a public utility may not begin the construction, purchase or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction, purchase or lease.

In considering a CPCN request, Chapter 8.5 requires the Commission to consider options other than the construction, purchase, or lease of an electric generating facility. *See* Ind. Code § 8-1-8.5-4.

Further, Ind. Code § 8-1-8.5-5 sets forth specific findings the Commission must make in order to approve and grant the requested CPCN. First, the Commission must make a finding, based on the evidence of the record, as to the best estimate of construction costs. Second, the Commission must find that either (a) construction will be consistent with the Commission's Statewide Analysis, if any, for the expansion of electric generation facilities, or (b) the proposed construction is consistent with a utility-specific proposal as to the future needs of consumers in the State of Indiana or in the petitioning public utility's service area [i.e., the utility's IRP]. Third, the Commission must find that public convenience and necessity require the facilities for which the CPCN is requested.[4]

[4] A fourth finding relating to coal-consuming facilities, pursuant to Ind. Code § 8-1-8.5-5(b)(4), does not apply to the proposed natural gas facilities.

"We have indicated in previous CPCN cases that 'least-cost planning' is an essential component of our [CPCN] law." *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC Dec. 29, 2002), *quoting Southern Indiana Gas & Electric Co.*, Cause No. 38738, at 5 (IURC Oct. 25, 1989). "We have defined 'least-cost planning' as a 'planning approach' which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* "However, we have emphasized that the [CPCN] statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve." *Id.* As this Commission has previously ruled: "[i]f an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service." *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC May 13, 1992); *see also Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4.

The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, perhaps as long as 30 years or more into the future. Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term. We must acknowledge that the economic forces at work may come from other supply side options or even demand side opportunities. The supply side and demand side certificating statutes implicate this by recognizing that an optimal balance of energy resources should consider both aspects in meeting customer needs.[5] A complication in the optimizing effort is the often disparate time horizons of the supply and demand sides of the balance. The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime.[6] Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery.[7] Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request.

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[5] Indiana Code §§ 8-1-8.5-4 and -10(c)(3).

[6] This effect can be see through the recovery of lost revenues a statutory component of utility DSM programs, which is in part a function of investment, of fixed cost, that is not being consumed at the expected rate.

[7] This timing inconsistency can reduce the value of demand side efforts because they are not avoiding long-lived fixed costs previously approved and included in rates. The full incremental impacts of demand side actions which occur after the approval of long-lived fixed costs are only affected over longer periods of time when future resources must be acquired and the timing and type of resource might change as a result of cumulative demand side activities.

i. Ind. Code §§ 8-1-8.5-4.

(1) Ind. Code § 8-1-8.5-4(1). In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities."

As a member of MISO, Vectren South interchanges power on a daily basis, and Vectren South's modeling considered and factored this arrangement into its decision to seek a CPCN. In addition, early in its resource selection process Vectren South identified a potential partner for a joint generation project. Witness Luttrell explained that this partner was interested in owning a minority share of a larger CCGT, and agreed to study locating such a unit on Vectren South's system. As studies ensued, the partnership appeared to be a viable resource option. As a result, the parties studied this joint ownership opportunity throughout 2017, but ultimately in January 2018 the potential partner provided notice that it would not proceed with such a project. Both Vectren South and the Commission have considered the interchange of power and pooling of facilities.

When assessing a CPCN petition, the Commission also considers the potential purchase of power by Vectren South. On June 20, 2017, Vectren South issued a RFP for dispatchable resources located in MISO Zone 6. Vectren South explained that its RFP specified this location requirement in order to satisfy MISO's requirement that a load serving entity have at least 67% of its resources located within its zone. The RFP sought dispatchable resources based upon the 2016 IRP analysis, which recommended that Vectren South retire nearly all of its baseload coal-fired capacity by the end of 2023. As a result, the RFP was designed to solicit baseload capacity to replace the 730 MWs provided by the retiring coal units. In response, Vectren South received nine qualified bids offering both PPAs and offers to build a CCGT and sell that unit or a partial interest in that unit to Vectren South. Using the expertise of Burns & McDonnell ("BMC"), Vectren South evaluated both quantitative and qualitative aspects of the competing bids. Based on BMC's analysis of the levelized cost of energy ("LCOE") of the bids, Vectren South selected the bid with the most favorable LCOE to compare to a self-build option. BMC's analysis was that Vectren South's self-build option had a better net present value than this best bid, and also exposed Vectren South to less risk versus long-term reliance on a merchant developer. Vectren South's rebuttal testimony noted that the merchant developer in question had in fact, even prior to its bid submission, withdrawn its project from the MISO queue without informing Vectren South.

The Commission acknowledges Vectren South's issuance of an RFP but believes the RFP was unduly restrictive given the rapid changes in technology and costs being seen in the market, especially regarding renewable energy. The narrow RFP with its focus on a large baseload dispatchable resource limited the options Vectren South evaluated to those larger than 600 MW. As a result, Vectren South foreclosed consideration of combinations of smaller resources that might have offered greater resource diversity, flexibility and cost efficiencies than reliance on the acquisition of a single large natural-gas facility. As discussed further below, expansion of the RFP to consider a broader spectrum of resource options would have also gone a long way to improve the metrics to limit risks from exposure to changes in market conditions and technologies.

Based on Vectren South's unduly restrictive RFP the Commission cannot conclude that Vectren South thoroughly evaluated the purchase of power in connection with Vectren South's request.

(2). Ind. Code § 8-1-8.5-4(2).

(a) The Refurbishment of Existing Facilities. In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. Ind. Code § 8-1-8.5-4(2). Ms. Aguilar summarized the following alternatives that Vectren South failed to fully analyze: (1) Retain Coal at Vectren South's existing plants and invest in refurbishments; (2) Retain the agreement with Alcoa for Warrick Unit 4; (3) Refuel the A.B. Brown unit(s) with gas; (4) A blended option, such as refueling one or more A.B. Brown units to gas and building a smaller CCGT; (5) Enter into a PPA with one of the bidders who responded to Vectren South's RFP; and (6) Retain its Broadway Avenue Unit 2. Pub. Ex 1, p. 8. Ms. Aguilar argued that Vectren South unfairly screened out these alternatives during the IRP process.

We agree with Ms. Aguilar and Dr. Boerger that Vectren South did not fully consider options to extend the life, or refurbish, existing units as required by Ind. Code § 8-1-8.5-4(1). *Id.* and Pub. Ex. 3, p. 6. This failure began during Vectren South's IRP process, when Vectren South screened out, without further study, viable refurbishment options. Pub. Ex. 1, p. 11. Vectren South's stated reason for shutting down the A.B. Brown units is premised on the need to replace the flue-gas desulfurization ("FGD") units at a cost of approximately $350 million. Pub. Ex. 3, p. 7. Dr. Boerger stated that with the exception of the current FGDs, the units operate quite well and are sized appropriately for a small utility like Vectren South. But as noted by Ms. Aguilar and Dr. Boerger, Vectren South's chosen FGD replacement technology was the most expensive and only technology reviewed. *Id.,* Pub. Ex. 3. Dr. Boerger pointed out that Vectren South did not consider lower-cost FGD replacement options, even though such options were available. He said that this decision made the continued use of the A.B. Brown units look less attractive in modeling than if those options had been included. A reasonable alternative would have been the refurbishment of these units through refueling. Pub. Ex. 3, p. 7. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT – approximately $45 million for both A.B. Brown units.

Vectren South considered a smaller 440 MW CCGT option in its last IRP, but Vectren South did not include it as part of any refueling options. Pub. Ex. 3, p. 9. Further, when Vectren South issued its RFP, it did so for 600-800 MW of dispatchable power, precluding smaller units that might have combined with refurbishment of other Vectren South units. Tr. B-25 - B-26. Vectren South did not fully model the conversion of one of the A.B. Brown units in its rebuttal testimony. Tr. E-45 – E-46.

On cross-examination, Vectren South witness Mr. Swiz estimated that the value of the stranded assets at the A.B. Brown unit alone will equal $220 million and that the system-wide total will be $270 million. While Vectren South argues that the CCGT option is the lowest cost, we find for the many reasons stated throughout this Order, including Vectren South's failure to sufficiently consider the refurbishment and continued operation of its existing facilities, we are not able to verify this claim. Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated. This conservative solution and risk avoidance strategy stands in stark contrast to proposed CCGT. Vectren South plans to submit a new IRP in 2019. We instruct Vectren South to closely consider our analysis in this Order and the Director's Report on the 2016 IRP of the flaws in their modeling for the 2016 IRP and the 2017 IRP Update and to present a more thorough

analysis that fully evaluates all possible options for continuing to provide reliable, efficient, and economical electric service.

(b) Conservation and Load Management. The evidence demonstrates that Vectren South has evaluated the CCGT against other reasonable generation alternatives, and included demand side management and energy efficiency ("DSM/EE") levels consistent with the targets approved in Cause No. 44927. Vectren South's modeling concludes that, even when the cost of energy efficiency has been significantly lowered, the CCGT is still the least cost reliable resource alternative to meet Vectren South's customers' future energy resource needs.

The Joint Intervenors criticize the assumptions used by Vectren South to model the cost of DSM/EE, arguing that the assumptions used by Vectren South were too high resulting in a higher cost of DSM/EE. Ms. Harris stated in her rebuttal that for purposes of this proceeding, Vectren South opted only to update its growth factors in its revised cost analysis in order to show the impact lower DSM/EE costs would have on the energy resources selected in its IRP. Ms. Harris explained that limiting the updates to the growth factors preserved the integrity of Vectren South's 2016 IRP. Petitioner's Exhibit No. 8-R, p. 3. We find that while some of the cost assumptions used by Vectren South could have been updated, on the whole it does not render Vectren South's analysis of DSM/EE unreasonable.

(c) Cogeneration and Renewable Energy Sources. Vectren South's IRP modeling process considered the potential for cogeneration facilities to serve its customers and adjusted its load forecast to reflect the potential for cogeneration facilities. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 99-103. Consequently, the potential for customer-owned generation resources, including renewable generation, to reduce Vectren South's load was evaluated as part of the IRP process that concluded the CCGT was necessary as part of least-cost planning. Nonetheless, while Vectren South may have considered renewable energy in the IRP, there is a lack of evidence that Vectren South made a serious effort to determine the price and availability of renewables. In addition, the economics of customer-scale renewable and cogeneration facilities appears likely to continue to improve and we anticipate that additional well-developed efforts to understand their customers' interest would serve to provide clarity to the lens of risk avoidance by minimizing the potential for unexpected demand side efforts. Therefore, we would expect Vectren South to ensure an enhanced consideration of renewable energy and customer-generator opportunities in future IRPs.

(3) Ind. Code § 8-1-8.5-5. A certificate may be granted only if the Commission makes the followings findings:

(a) Best estimate of construction, purchase, or lease costs based on the evidence of record. The cost estimates for Vectren South's proposed CCGT were developed and presented by witness Diane Fischer. Black & Veatch developed a design basis and conceptual design and thereafter developed a cost estimate. Several conceptual designs were first developed. From that, ten plant alternatives for purposes of estimating costs were identified. This was later narrowed to seven alternatives for which detailed costs were developed. Competitive bids were obtained for the equipment and materials. Based upon Black & Veatch's experience as an engineering, procurement and construction ("EPC") contractor, Black & Veatch was able to estimate indirect costs, contingency, overhead, and profit for the EPC contractor. Bids were also received for construction. Ultimately, Ms. Fischer testified that the cost estimate for the proposed CCGT had been refined to +/- 10%. The total estimated project cost (excluding owner's costs) was $582,000,000. The owner's

costs were then provided by witness Games, including insurance, contingency, study, and AFUDC. The total cost estimate was $781,000,000.

(b) Consistency of the CCGT with Vectren South's Utility-Specific IRP and the Statewide Analysis. Ind. Code § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether Vectren South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. The final version of that report was issued after the parties' pre-filing deadline, but before the evidentiary hearing and was admitted into evidence as Pet. Admin. Not. Ex. 2. Included in that report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including Vectren South.

In Appendix 12 of the Statewide Analysis, the concept of Resource Diversity is explained:

> In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes.

Vectren South's proposal to concentrate its base load capacity from five different generating units located at three different sites down to just three generating units (one of them constituting 70% of Vectren South's baseload capacity) located at two sites appears to be contrary to the concept of resource diversity.

On page 5 of the 2018 Statewide Analysis it says:

> A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake.

In explaining the importance of sound long-range planning on page 56 of the 2018 Statewide Analysis, it says, "[t]he credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." However, we find nothing in Vectren South's evidence convinces us that its proposal provides any off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources. To the contrary, Vectren South's proposal seems to close most off ramps for the foreseeable future.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with Vectren South pointing to its CCGT conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co.*, Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, Order p. 36 (IURC Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at 35.

At the outset, Mr. Games testified that Vectren South sent a request for information ("RFI") to original equipment manufacturers ("OEM") for CCGT pricing information before Vectren South's 2016 IRP. Tr. E-89 – E-91. Mr. Chapman stated that under any of the IRP models, the CCGT is the least expensive. Tr. A-27 - A-28.

Dr. Boerger testified that Vectren South did not consider other viable options such as refueling and smaller combinations of generation assets to meet its needs, Pub. Ex. 3, p. 1 – p. 2, which would be more prudent for a small utility like Vectren South. Pub. Ex. 3, p. 5. Vectren South excluded possible options such as maintaining Culley 2, Pub. Ex. 3, pp. 11-12, and did not allow the refueling of the A.B. Brown units to be included in any of its model runs. *Id.* Vectren South kept a smaller, 440 MW CCGT from being combined with a refueled A.B. Brown unit. Pub. Ex. 3, p. 13. Mr. Games admitted that Vectren "never [ran] a risk analysis of portfolios including a 1 X 1 CCGT instead of a 2 X 1[.]" Tr. E-50. Vectren South also did not allow for proposals of joint projects to be built at it's A.B. Brown site, which would eliminate the potential for congestion problems Vectren South identified as a problem in its RFP responses. Vectren South's Strategist model limited the amount of capacity purchases that a given portfolio could make. Tr. D-73. This had the effect of automatically screening out PPAs that could have been combined with other resources to meet Vectren South's capacity needs. The Director's Report on Vectren South's 2016 IRP noted that Vectren South failed to model a wide range of gas prices, making the "range of fuel price projections… unduly limited[,]" Tr. D-85, and Vectren South's re-run of gas costs did not model higher prices in a wide enough range. Tr. D-86. As noted by Mr. Alvarez, Vectren South's model retired the BAGS 2 unit in 2024 without evidence of any engineering reason to do so. Pub. Ex. 2, pp. 13-14.

Dr. Boerger also found that Vectren South modeled the cost of its proposed CCGT to be $200 million less than the cost of the project presented in the testimony of Vectren South witness Games. Pub. Ex. 3, p. 2. The consequence of excluding $200 million in Vectren South's NPV calculation had the effect of making the CCGT option look more favorable. Pub. Ex. 3, p. 14. Without adding the $200 million back into the model runs, Vectren South's analysis is skewed. Pub. Ex. 3, p. 18 – p. 19. Mr. Games admitted that his testimony about the estimates was confusing, stating "[w]e started off with 2017 dollars, and those were -- then overheads were added, anticipated profit with the EPC, contingency for EPC, and escalation was added to get to the 582 million." Tr. E-15 – E-16. Mr. Lind took issue with Dr. Boerger's analysis, but admitted that Vectren South did not include $130 million in owner's costs when it compared its self-built CCGT to other options offered in the RFP and otherwise. Tr. A-36 – A-38; Tr. D-7 – D-8. When questioned why BMC did not use the $781 million figure, Mr. Lind stated that the $630 million estimate used for modeling was a +/- 50% estimate; the $781 million had a more certain +/- 10% range of accuracy. Tr. A-35; Tr. C-61 - C-62, C-74. BMC's projected cost of $580 - $650 million was used to weigh the economics of potential projects. Tr. A-

36 – A-38. And Vectren South witness Mr. Vicinus ran his "low regulatory" model using the $630 million estimate. Tr. D-98.

In response to the OUCC's criticism of its modeling, Vectren South's rebuttal included a new model run that refueled one of the A.B. Brown units, and added 200 MW of solar. Tr. D-12 – D-13. Vectren South used this rebuttal modeling to try to reinforce its original request for a 850 MW CCGT. Both Mr. Lind and Mr. Games acknowledged, however, that the addition of 200 MW of solar was not the best choice to meet MISO's PRM, because MISO would only give Vectren 100 MW of credit for the 200 MW of solar. Tr. E-15. The revised model also did not take into account the fact that solar costs between $1,200 - $1,800 per MW, Tr. D-16 – D-17, and Vectren South did not model any storage to counter the inherent intermittency of solar resources. Tr. D-14.

While we find Vectren South's request is "consistent" with its 2016 IRP, the subsequent modeling for this case effectively screened out multiple less-expensive alternatives. Vectren South did not allow its models to choose refueling or smaller units in combination. While Vectren South's rebuttal modeling runs included refueling of the A.B. Brown units in various configurations, the rebuttal modeling was not used to make Vectren South's decision of what generation form to choose. Tr. D-14. We view the rebuttal modeling as an after-thought used to buttress Vectren South's initial request.

Vectren South had sufficient time to conduct its analysis in a way more open to smaller-scale options that would correct the modeling deficiencies that have been identified. It seems straight-forward to suggest that smaller-scale options, especially for a relatively small electric utility, serve to minimize the risk should a challenge arise at any one option. As noted above, minimizing supply side long-term investment risk in an environment of rapid technological innovation is an attractive characteristic in a utility resource proposal. Vectren South should use its scheduled 2019 IRP process to address problems in its modeling, incorporate more options for partnering with other entities and competitive inquiries into smaller-scale options that can be acted upon swiftly to meet the end-of-2023 date upon which additional capacity may be needed.

(c) Public Convenience and Necessity. Ind. Code § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CCGT. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. Ind. Code § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

"[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In *General Motors*, the court approved the Commission's consideration of the impact on employment in the coal industry in its public interest determination. *Id.*

The parties dispute whether Vectren South accurately and adequately evaluated risk in its analysis of alternative portfolios and selection of the proposed CCGT. As noted earlier, under Ind. Code § 8-1-8.5-4, we are required to take into account other methods for providing reliable, efficient,

and economical service, and we find utility risk analyses play an important role in comparing alternative portfolios.

Joint Intervenors argued that Vectren South's risk analysis is inadequate for multiple reasons. Joint Intervenors note that the risk analysis has not been updated since the 2016 IRP, despite Vectren South having updated inputs available for several inputs, including the estimated cost of its preferred build, and adequate time to re-run the model. Joint Intervenors complain that Vectren South ignored known material risks in a manner that biased results in favor of its preferred portfolio, including taking a one-sided view of capacity purchase and market purchase risks and failing to consider the potential for future methane regulations. Joint Intervenors further argue that Vectren South arbitrarily scored several metrics and designed others to conceal rather than measure obvious risks of the preferred portfolio.

We find merit in several of Joint Intervenor's critiques and are further concerned that Vectren South has not fully responded to critiques in the Final Director's Report on the 2016 IRPs. We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing, and that it has sufficient time to do so now before moving forward. Vectren South updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT.

We are further concerned that Vectren South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.*, Cause No. 44794, 2017 WL 1632316, Order p. 28 (IURC Apr. 26, 2017). Joint Intervenors point out that Vectren South's risk analysis took a one-sided view of capacity purchase and market purchase risks. *See* JI Ex. 2 at 43; Vicinus Rebuttal. Vectren South offered no rebuttal explaining its one-sided view of market risk, which assumed surplus capacity and generation offers only benefits to ratepayers. JI Ex. 2 at 20-21. That view of market purchases is only true when market prices and/or load are high. JI Ex. 2 at 21. Further, Vectren South's Docket Entry response of October 5, 2018, presents portfolio results that suggest the material weight at which opportunity sales influences the analysis.[8] Heavy dependence on market revenues to support a regulated investment choice is a speculative influence that we find must be materially discounted to limit the risk of customers being saddled with

[8] The submitted table indicates that the advantage of the Preferred Portfolio in comparison to (1) BAU to Gas Conversion escalates from 1.3% to 3.5% when the opportunity sales sharing moves from 50% to 100%.

uneconomic options should such speculation unfold differently than forecasted. A metric biased in favor of portfolios with surplus generation is speculation we decline to embrace.

Vectren South's own witnesses and others acknowledged risks related to relying on gas generation, but Vectren South only considered carbon dioxide emission reductions when it evaluated environmental risk. We agree that was too narrow an approach to environmental risk and one that biased the analysis in favor of gas-fired generation.

The Commission appreciates the metrics developed and used by Vectren South in the 2016 IRP, but we agree with the Joint Intervenors that the use of these particular metrics also obscured critical characteristics of the preferred portfolio. One of Vectren South's IRP objectives was to develop a plan with flexibility to adapt to market conditions and technological change to minimize risks to shareholders and customers. Specific metrics to measure resource portfolio balance and flexibility included concentration on one technology, the number of technologies and having resources remote from Vectren South's load. A critical piece of information these metrics overlook is that the acquisition of an 850 MW resource must be evaluated relative to the load to be served. Vectren South's 2016 IRP Base peak load forecast is for the summer peak to increase from 1,109 MW in 2019 to 1,198 MW in 2036. The acquisition of an 850 MW generation facility represents approximately 77 percent of the 2019 peak load and just under 71 percent of the summer peak load for 2036. We are hard pressed to see how reliance on one facility for so much of the Vectren South system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change.

Therefore, we conclude that Vectren South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. The proposed large scale single resource investment for a utility of Vectren South's size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation. As a result, we find that Vectren South has not demonstrated through the evidence of record that the public convenience and necessity require the building of an 850 MW CCGT. Therefore, Vectren South's request for a CPCN to construct a 850 MW CCGT is denied.

B. Vectren South's Request for a CPCN for Culley compliance projects and related relief. Vectren South's preferred portfolio also includes the construction of various environmental projects that Vectren South contends are needed so that Culley Unit 3 can continue to operate beyond 2023. Vectren South's petition seeks relief for these projects under Ind. Code ch. 8-1-8.4 as "federally mandated" projects.

i. Ind. Code ch. § 8-1-8.4 ("Chapter 8.4").

(1) Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (2) The federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States

Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

The description of the Culley 3 Compliance Projects was set forth in the direct testimonies of Ms. Fischer and Ms. Retherford. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. No party disputed that the dry handling bottom ash conversion or spray dryer evaporator system qualify as compliance projects to meet federally mandated requirements. The OUCC challenged whether the closure of the existing pond qualified for relief but did not contend that it was not federally mandated. For the reasons described below, we find that these projects all constitute compliance projects to meet federally mandated requirements as those terms are defined in Ind. Code §§ 8-1-8.4-2 and -5.

Vectren South witness Retherford testified that the dry handling bottom ash system is required to comply with the ELG Rule, which was promulgated under the federal Water Pollution Control Act. Petitioner's Exhibit No. 9, p. 11. The ELG rule prohibits further wet handling of fly and bottom ash. This system will enable ash from Culley Unit 3 to be disposed of in a landfill, hauled back to a surface mine in accordance with applicable surface mining regulation or recycled rather than being washed into the ash pond as part of a water discharge.

Ms. Retherford further explained that the spray dryer evaporator system was necessary to ensure compliance with ELG-imposed limits on FGD wastewater discharge. She noted that this system functions effectively as a ZLD system and enables Vectren South to utilize the alternative ELG-imposed compliance date of December 31, 2023, and to meet future more stringent ELG wastewater discharge limits.

Ms. Retherford testified that construction of a new, lined process and storm water retention pond is required to comply with the ELG Rule. As we have already noted, projects necessary to comply with the ELG Rule, promulgated pursuant to the federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*), constitute a federally mandated requirement. The only dispute, raised by OUCC witness Aguilar, pertains to Vectren South's plans to close the existing Culley West pond so that the new lined pond can be built at the site. Witness Retherford testified that there are two reasons the Culley West pond is closing: (1) the pond was taken out of service prior to the 2015 deadline and the CCR rule requires that it be closed by 2020; and (2) the current space limitations require that the new stormwater retention and process water pond be constructed on the current location. Thus, there is no dispute that costs associated with the construction of the new lined pond are incurred pursuant to a federally mandated requirement. The dispute is whether the costs to close the Culley West pond so that the new pond can be built on top of that location, also qualify as federally mandated costs.

The OUCC identifies three reasons closure costs for the Culley West pond should not be considered federally mandated costs. First, OUCC witness Aguilar contends that Vectren South has been collecting depreciation and asset retirement costs in base rates, which include the closure of ash ponds. Public's Exhibit No. 1, p. 28. However, Vectren South witness Retherford responded that finalization of the CCR rule on April 17, 2015 imposed more stringent requirements to close the ash pond. The CCR rule imposed an obligation to dewater, cap and/or remove ponded ash. Petitioner's Exhibit No. 9-R, pp. 24-25.

On rebuttal, Mr. Swiz stated Vectren South's existing depreciation rates include an estimated level of cost of removal that was designed well before the implementation of requirements to close the ponds in accordance with the environmental regulations described by Ms. Retherford. The assumed removal costs in the demolition study provided in Cause No. 43839 (Vectren South's most recent general rate case), estimated $1.1 million to close both of the Culley Ash Ponds based on cost of backfill, grading and seeding. By comparison, the estimate for closure of one ash pond in this proceeding is $19.969 million. Petitioner's Exhibit No. 13-R, pp. 6-7; Petitioner's Administrative Notice 1.

Consequently, we find that costs associated with CCR closure have not been included in Vectren South's depreciation rates, which were last updated prior to finalization of the CCR Rule.

Second, the OUCC contends that other utilities are not tracking pond closure costs as Federally-Mandated CCR Projects. Public's Exhibit No. 1, p. 28. Vectren South witness Swiz noted that no utility had proposed such recovery yet but that one utility specifically indicated that it would present closure related activities as recoverable under the Federal Mandate Statute. Petitioner's Exhibit No. 13-R, pp. 6-7. Mr. Swiz explained that Duke, IPL and NIPSCO did not ask for recovery of their pond closure costs in the proceedings Ms. Aguilar cited, and in fact the order in Cause No. 44765 specifically notes that Duke anticipates presenting closure related activities of existing surface impoundments and their associated costs in a future proceeding. Petitioner's Exhibit No. 13-R, p. 6, citing *Duke Energy Indiana*, Cause No. 44765, at *7 (IURC May 24, 2017). Each of the cases Ms. Aguilar cited were settled cases containing non-precedential language. Nevertheless, Mr. Swiz pointed out that the NIPSCO Order in Cause No. 44872, suggests that the OUCC agreed that closure costs can be recovered as federally mandated costs. Petitioner's Exhibit No. 13-R, p. 7.

Third, the OUCC contends that Vectren South should have presented alternative suitable locations to the West Pond for consideration. However, Ms. Retherford testified that the location was chosen because there was limited space at the Culley generating station. In other words, there was not an alternate location to explore. The statutory requirement to consider options does not require a utility to present alternatives that are not practical or feasible. Accordingly, we find the Culley 3 Compliance Projects are all federally mandated requirements and that Vectren South described them in its application.

(2) Energy utilities seeking recovery of Federally Mandated Costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax or financing costs and describe the costs to be recovered. Ind. Code §§ 8-1-8.4-4 and -6(b)(1)(B). We have already found that the Culley 3 Compliance Projects constitute projects required by federally mandated requirements. Consequently, the costs associated with these projects constitute Federally Mandated Costs. These costs will consist of capital, operating, maintenance, depreciation, tax and financing costs. Vectren South identified the estimated costs to be recovered as Federally Mandated Costs. Costs associated with the dry handling bottom ash handling system and spray dryer evaporator system were identified by Vectren South witness Fischer. Petitioner's Exhibit No. 6, pp. 16-18, 26-28. Costs associated with the construction of a new lined process water and storm water retention pond were identified in Ms. Retherford's testimony. Petitioner's Exhibit No. 9, Attachment AMR-1. No party disputed the cost estimates for the Culley 3 Compliance Projects. Based on the evidence presented, we find that Vectren South has identified

federally mandated costs and reasonably described those costs. Those total costs are $95 million, and they are hereby approved. Petitioner's Exhibit No. 4, p. 26.

(3) Compliance with Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-6(b)(1)(C)) and 8-1-8.4-7(b)(3)). No party disputed that the Culley 3 Compliance Projects will allow Vectren South to comply with ELG and CCR or that ELG and CCR are federally mandated. We previously addressed the OUCC's objections related to appropriateness of recovery. We have already found that the ELGs and CCR Rule are federally mandated requirements within the meaning of Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3). Based on the evidence presented, we find that Vectren South's Culley 3 Compliance Projects, will allow the utility to comply with the ELGs and the CCR Rule. Therefore, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(C).

(4) Alternative Plans for Compliance (Ind. Code §§ 8-1-8.4-6(b)(1)(D) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-6(b)(1)(D) requires the Commission to examine "[a]lternative plan that demonstrate that the proposed compliance project is reasonable and necessary." Vectren South witness Diane Fischer testified about Black & Veatch's evaluation of the ELG Compliance Program for Culley to identify potential FGD discharge water treatment alternatives and ash transport water alternatives that could be implemented to comply with the ELGs. She sponsored two written reports setting forth Black & Veatch's analyses of the alternatives. Ms. Fischer testified that each of the potential discharge treatment technology alternatives assessed by Black & Veatch were screened for design concept feasibility, capital expense and operating expense.

With respect to FGD discharge water treatment, two main treatment alternatives were considered: (1) FGD treatment and discharge; and (2) zero liquid discharge ("ZLD"). Three technology types were evaluated within these two treatment alternatives: (1) for FGD treatment and discharge, physical/chemical pretreatment with biological treatment technology, (2) for ZLD, spray dryer evaporator technology, and (3) also for ZLD, brine concentrator/crystallizer technology. Ms. Fischer testified that multiple vendors providing such technologies were evaluated. A sensitivity analysis was then performed for each technology and vendor. Ms. Fischer's Discharge Treatment Report also included a cost assessment of all alternatives considered. Petitioner's Exhibit No. 10, p. 7. Ms. Fischer testified that Black & Veatch provided Vectren South with a final overall assessment of each technology and vendor offering based on Black & Veatch's analysis and the following attributes: (1) start-up/ramp up reliability; (2) technology readiness risk; (3) adaptability to sensitivity analysis scenarios; (4) operation and control risk; (5) heat rate impact risk; (6) number of operators; (7) capital and annual O&M costs; (8) susceptibility to future environmental regulations; (9) overall financial stability and credit rating. Black & Veatch ultimately recommended that Vectren move forward to a detailed engineering phase with Stochastic Differential Equation ("SDE") type technology if the maximum FGD wastewater flow rate of between 50 and 80 gpm is achieved through future testing and operations. Ms. Fischer explained the SDE solution ranks the highest among all technologies based on the attributes discussed above and the solution is economically viable and provides a zero discharge solution if the minimum FGD wastewater flow rate of between 50 and 80 gpm is achieved. The conceptual design evaluation indicated the SDE can be feasibly located and tied into the existing equipment at Culley. In addition, Ms. Fischer stated the ZLD solution provides certainty that any future change in EPA regulations would not apply at Culley since there would be no discharge of FGD wastewater.

With respect to ash transport, Ms. Fischer described Black & Veatch's analysis to identify alternative ash transport solutions that could be implemented at Culley to comply with ELG requirements, focused specifically on identifying options for removal and dewatering of bottom ash from the Culley Unit 3 boiler with truck transport and disposal of the dry material at an off-site location. Black & Veatch evaluated two categories of technologies: (1) dry conversion of the bottom ash system and (2) closed loop wet sluicing system. For dry conversion system, Black & Veatch evaluated a submerged chain conveyor under the existing bottom ash hopper. For the closed loop wet sluicing system, Black & Veatch evaluated both a dewatering bunker and a remote submerged chain conveyor. In comparing all technologies, Black & Veatch used the following quality attributes to select the preferred treatment: technical feasibility; total installed cost, O&M cost, estimated additional manpower ("FTE"), estimated footprint, major equipment, advantage, disadvantages and reliability. Ms. Fischer's testimony discussed in detail the advantages and disadvantage of each alternative. Black & Veatch prepared cost estimates for all technologies considered for addressing ash transport water. Black & Veatch ultimately recommended the submerged chain conveyor for Culley 3 compliance with ELG requirements, due to the complexity of design and comparatively higher installed cost of the other alternatives.

The only evidence offered in opposition as being an alternative plan was the OUCC's conclusory statement about possible alternative locations for the new lined pond. As we have previously found, the chosen site was selected because there are no alternative locations.

While the Commission gives significant weight to cost-effective planning and decision making when considering alternatives, the Federal Mandate Statute does not require that a utility demonstrate that the chosen compliance plan is the least cost option. Consistent with the Commission's finding in Indianapolis Power and Light's recent proceeding, Cause No. 44794 (IURC 4/26/2017), p. 30, 2017 Ind. PUC LEXIS 114, *92, (finding "it is important that the Petersburg Station is able to continue to operate on coal and protect customers from potential price volatility in the gas markets"), a reasonable alternative can be, and often is, a solution that includes risk balancing through a diversified portfolio.

Based on the evidence presented, we find that Vectren South considered alternative plans for compliance with the ELGs and the CCR Rule. The evidence shows that the Culley 3 Compliance Projects are reasonable and necessary.

(5) Useful Life of the Facility (Ind. Code §§ 8-1-8.4-6(b)(1)(E) and 8-1-8.4-7(b)(3)). Mr. Games testified that the investments in the Culley 3 Compliance Projects will allow for the continued operation of Vectren South's most efficient coal fired unit. Ms. Retherford described the environmental regulations requiring the Culley 3 Compliance Projects in order for Culley Unit 3 to continue operating. Ms. Retherford explained how closure of the Culley West pond will extend the useful life of Culley 3, because closure of the Culley West pond is necessary to provide a suitable location to construct a new pond that can continue to take non-CCR process water discharged from Culley Unit 3 and plant stormwater (i.e. surface water) which flows into the West Pond. Without this new lined process and stormwater pond, continued operation consistent with applicable regulations would be impossible after the Culley East pond commences closure.

No party disputes that issuance of a CPCN for the Culley 3 Compliance Projects will extend the useful life of Vectren South's Culley 3 unit or that Culley 3 would be required to retire in the near future if the Culley 3 Compliance Projects are not completed.

Based on the evidence presented, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

(6) Conclusion. We find that the Culley 3 Compliance Projects will allow Vectren South to comply directly or indirectly with one or more federally mandated requirements and that public convenience and necessity will be served by the Culley 3 Compliance Projects.

ii. Accounting and Ratemaking Issues Associated with Culley Compliance Projects. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3)and IC 8-1-2-42(g)(3).
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

(1) Accounting and Ratemaking Treatment for ECA. Vectren South requests authority to implement a new annual rate adjustment mechanism ("ECA") pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs. Vectren South also requests approval of proposed changes to its electric service tariff relating to the proposed ECA mechanism, including the proposed Appendix E. Ind. Code §8-1-8.4-8 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Vectren South witness Swiz described how the eligible costs associated with the Culley 3 Compliance Projects will be incorporated into the proposed ECA mechanism. He testified Vectren South will prepare in each annual filing a revenue requirement calculation accumulating all eligible costs incurred through December 31 of the previous calendar year. To provide for timely recovery, Mr. Swiz testified the proposed ECA will project an annualized level of expense related to the approved projects for the 12-month effective period. Mr. Swiz stated the annual revenue requirements

will capture eligible new capital investments (both in service and Construction Work in Progress) related to the Culley 3 Compliance Projects, multiplied by the applicable rate of return, with depreciation, O&M and property tax expenses associated with the projects, and recovery of the regulatory assets recorded through interim deferral of depreciation expense, plan development expense, and PISCC, added to the resulting total. The revenue requirement for those projects will be the basis for the recovery of 80% of the eligible revenue requirement amounts in each annual ECA filing.

Mr. Swiz also described Vectren South's proposal to defer and subsequently recover depreciation expense as well as costs associated with development of the Culley 3 Compliance Projects through the ECA. The cumulative deferred balances of the regulatory assets recorded through interim deferral of such depreciation expenses would be amortized over the remaining life of the assets (20 years) and the amortization amount would be included in the ECA revenue requirements. Mr. Swiz stated the costs of development of the projects would be included for recovery within the ECA, with the balance amortized over a period of three years.

Vectren South proposes the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the weighted average cost of capital ("WACC"), by total new capital investment related to the approved projects. Mr. Swiz testified Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism under Cause No. 44910, which is based on a return on equity ("ROE") of 10.4% as approved in Cause Nos. 43111 and 43839, Vectren South's two most recent base rate cases. Mr. Swiz stated the equity component of the rate used in the ECA revenue requirement calculation will be grossed up for recovery of income taxes, both state and federal, at then current rates.

Mr. Swiz testified that approved recoveries within each ECA filing will be calculated by taking the billing determinants by month multiplied by the applicable rates and charges for the ECA period. Any under recoveries resulting from instances in which ECA rates and charges are not in place for a full month will be recovered as an under-recovery variance in a subsequent ECA proceeding. Vectren South proposes to allocate ECA costs pursuant to the four-coincident peak allocation percentages for Vectren South utilized in its Cause No. 43406 RCRA15 and 43405 DSMA15 rate mechanisms.

With respect to the treatment of operating income, Mr. Swiz testified Vectren South will adjust its statutory earnings test under Ind. Code § 8-1-2-42(d)(3) to include the incremental earnings from approved ECA filings.

Mr. Swiz testified Vectren South proposes to file its ECA petitions and cases in chief annually, on May 1 of each year, with new ECA rates and charges becoming effective August 1 of each year. Each filing will be based on capital investments and expenses through the twelve months ended December of the prior calendar year. Variances will be reconciled in each ECA filing and recovered over the subsequent 12 month rate effective period. Vectren South seeks approval of its proposed Sheet No. 69, Appendix E, Environmental Cost Adjustment. Additional changes to Vectren South's rate schedules in its tariff are needed to reflect that the ECA will be applied monthly.

Industrial Group witness Gorman recommended that the ELG costs associated with the Culley 3 Compliance Projects be recovered within a base rate proceeding and not through the proposed ECA. He cited Vectren South's overall rate of return and stated Vectren South's costs have declined since

the last base rate case. He also suggested that Vectren South should be permitted to recover a return on investment of no more than 9.8%.

Mr. Swiz explained on rebuttal that under the statutory test under Ind. Code § 8-1-2-42(d) and -42.3, performed in Vectren South's most recent FAC proceedings as of the time his rebuttal testimony was filed (Cause No. 38708 FAC 120), Vectren South's comprehensive earnings compared to authorized levels, including both changes in expenses and revenues, show that Vectren South is currently under-earning by approximately $6.5 million of net operating income and has been under-earning since February 2017. Mr. Swiz explained that depreciation and operating expense are driving much of these results, and Mr. Gorman does not capture those expenses in his calculation.

Eligibility for recovery through Ind. Code ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Ind. Code § 8-1-8.4-7(c)(1). In any event, we find that Mr. Swiz has adequately explained why Mr. Gorman's position is incorrect.

Mr. Swiz testified that pursuant to Ind. Code § 8-1-8.4-7, Vectren South seeks ratemaking treatment for 80% of the costs associated with the Culley 3 Compliance Projects through its proposed ECA mechanism. Specifically, Vectren South seeks timely recovery of all federally mandated costs associated with the Culley 3 Compliance Projects, including capital costs, AFUDC, post-in-service carrying cost charges ("PISCC"), O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in Vectren South's next rate case.

Vectren South proposes to implement construction work in progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during construction of the Culley 3 Compliance Projects. In connection with CWIP ratemaking treatment, Vectren South will remove from the AFUDC-eligible balance the amount of investment included for recovery in the ECA, so that only the amount of the Culley 3 Compliance Projects investment not currently being recovered in the ECA would be eligible for AFUDC.

Mr. Swiz testified that Vectren South proposes to accrue post-in-service carrying charges on all eligible new capital investment from the date it is placed in service until the date it is included in rates. He explained the PISCC balances will be multiplied by the pre-tax rate of return within the ECA revenue requirement, at the WACC rate described herein. Unlike other utilities who have been granted such authority, Vectren South is not seeking to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance discussed below.

OUCC witness Aguilar opposed Vectren South's request to recover pond closure costs for the Culley 3 Compliance Projects as part of the ECA because the OUCC's position is that Vectren South is already collecting pond closure costs within its depreciation rates. Ms. Aguilar also testified that neither Duke, IPL, nor NIPSCO are tracking pond closure costs. We have already addressed these positions and rejected them.

Based on the evidence presented, we find that the proposed ECA mechanism should allow for the timely and periodic recovery of 80% of Vectren South's approved federally mandated costs. We further find that Vectren South's request for approval to adjust its authorized net operating income to

reflect an approved earnings associated with the Culley 3 Compliance Project for purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1).

Vectren South is authorized to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South is authorized to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South is authorized to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South is authorized to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South's proposed cost allocation factors are also approved.

(2) Accounting and Ratemaking Treatment for Deferred Costs. Indiana Code § 8-1-8.4-8 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Vectren South proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with these projects.

Based on the evidence presented, the Commission finds Vectren South is authorized to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects, and Vectren South may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

(3) Depreciation Treatment. Vectren South proposes to utilize a depreciation rate of 5%, representing a 20-year life on these investments. Mr. Swiz testified the proposed depreciation rate for the investments aligns with the estimated remaining life of Culley Unit 3.

No party opposed Vectren South's proposed depreciation rate for the investments required for the Culley 3 Compliance Projects.

Based on the evidence presented, we find that Vectren South's proposal to depreciate the individual projects included in the Culley 3 Compliance Projects based on a 5% depreciation rate is reasonable and is approved.

C. Recovery of Prior Pollution Control Investments. Our January 28, 2015 and June 22, 2016 Orders in Cause No. 44446 (the "44446 Orders") (1) granted Vectren South a CPCN for A.B. Brown Unit 1 and 2, Culley Unit 3 and Warrick Unit 3 clean coal technology projects and (2) authorized Vectren South to recover federally mandated costs associated with federally mandated requirements at A.B. Brown Units 1 and 2 (collectively the "MATS Projects"). Rather than recovering

the costs of the MATS Projects through a tracking mechanism as authorized by Ind. Code § 8-1-8.4-7, Vectren South sought, and we granted, authority to defer these costs for recovery in a future proceeding. Vectren South now seeks to commence recovery of the MATS Projects' costs through the ECA pursuant to Ind. Code § 8-1-8.4-7.

Vectren South witness Swiz described the proposed recovery through the ECA in more detail. He indicated that Vectren South proposes recovery of the MATS Projects to begin on January 1, 2019 with the approval of ECA rates and charges recovering the specified revenue requirement. In accordance with applicable statutory requirements, Vectren South proposes to recover the 80% of eligible revenue requirements amounts for post-in-service carrying costs, incremental depreciation and property taxes and financing costs that Vectren South incurred to construct the MATS Projects and deferral of the remaining 20% of these costs for subsequent recovery in a base rate case. Vectren South will prepare an annual revenue requirement as part of the ECA to capture eligible capital investments in plant related to the MATS Projects, multiplied by the applicable rate of return, with depreciation, O&M, and property tax expenses associated with the MATS Projects added to the resulting total. To provide for timely recovery, Vectren South's proposed ECA will project an annualized level of expense related to these approved projects for the 12-month effective period.

Depreciation associated with the MATS Projects will be based on the currently approved depreciation rates applicable to the assets, as approved in Vectren South's last electric base rate case (Cause No. 43839). The pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism, Cause No. 44910. This WACC, approved by the Commission, represents an updated actual capital structure as of the cut-off date of each TDSIC filing, and includes the typical items captured in Vectren South's base rate case capital structure. This rate will be used in the ECA revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. O&M expense included for recovery in the ECA will reflect an annualized level of expense related to the MATS Projects. This O&M expense represents incremental chemical costs and other expenses associated only with the MATS Projects.

No party objected to Vectren South's proposal to commence recovery of the MATS Projects' costs, currently being deferred, through the ECA. We previously found the MATS Projects costs qualify as federally mandated costs in the 44446 Orders. While Vectren South proposed, and we approved of, deferral of these costs in lieu of the recovery through a periodic retail rate adjustment mechanism, Vectren South now seeks to recover the costs in accordance with Ind. Code § 8-1-8.4-7(c). We find that Vectren South shall be authorized to commence recovery of these MATS Projects' costs pursuant to Ind. Code § 8-1-8.4-7 through the ECA in accordance with the procedures outlined in Mr. Swiz's testimony.

6. Confidentiality. Vectren South filed motions for protection and nondisclosure of confidential and proprietary information on March 20, 2018, August 21, 2018, and September 10, 2018, respectively. In its motions, Vectren South states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. Docket entries were issued on March 29, August 27, and October 4, 2018 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the

information for which Vectren South seeks confidential treatment is confidential trade secret information pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is approved.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA is approved as described in this Order.

4. Vectren South's proposed ECA, and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA is approved.

5. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

6. This Order shall be effective on and after the date of its approval.

HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR; FREEMAN ABSENT:

APPROVED: APR 2 4 2019

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M Becerra

Mary M. Becerra
Secretary of the Commission

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 115
Vectren 2020 IRP

2019/2020

Integrated Resource Plan







VECTREN

A CenterPoint Energy Company

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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.		2019 IRP submitted on June 30, 2020
(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.		12 Technical Appendix Attachments 1.1-8.3
(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.vectren.com/irp
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.		3.4 Data Requests Summary
(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.		3 Public Participation Process
(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:		3.1 Process Description
(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.		3 Public Participation Process; 12 Technical Appendix Attachment 3.1
(2) The utility may hold additional meetings.		3.1 Process Description
(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and		3 Public Participation Process

(C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.		
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.		4.6 Base Energy And Demand Forecast
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.		11.1.3 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.		7.3. Alternate Scenarios; Figure 7.8 Vectren Peak Demand Forecast
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.		6.2 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.		6 Resource Options; 8 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.		6.3 Potential Future Options Modeling Assumptions; Figure 6-5 Tier 1 Cost Summary
(7) The resource screening analysis and resource summary table required by section 7 of this rule.		Figure 11.35 New Construction Alternatives; Figure 6-5 Tier 1 Cost Summary
(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.		8.1 Portfolio Development
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(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.		10 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.		List of Acronyms/Abbreviations with Definitions; 2 Vectren's IRP Process; 3 Public Participation Process; 4 Customer Energy Needs; 6 Resource Options; 7 Model Inputs and Assumptions; 8 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this		12 Technical Appendix Attachments

rule. If 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.		6.2.4 Energy Efficiency; 11.1.1 Forecast Inputs; 12 Technical Appendix Attachment 4.1 2019 Long-Term Electric Energy and Demand Forecast Report
(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.		11.1.4 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.		1.3.3.1 Advanced Metering Infrastructure (AMI)
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).		1.3.13 Contemporary Issues
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning;		4.4 Customer Owned Distributed Energy Resources

(B) transmission planning; (C) distribution planning; and (D) load forecasting.		
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.		4.3 Model Framework; 7.1 Resource Model
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.		9.1.7 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.		11.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.		8.1 Portfolio Development
(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.		7.2. Reference Case Scenario; 7.3 Alternate Scenarios
(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.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(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. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with		7.2 Reference Case Scenario

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.		7.3 Alternate 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.		6.4 Transmission Considerations
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and		4.3 Model Framework; 7.1 Resource Model; 6.3.2 DSM, 4.6 Energy and Demand Forecast (Reference Case); 6 Resource Options; 7 Model Inputs and Assumptions; 8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio

(iv) analysis of risk and uncertainty.		
(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.		11.3.5 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.		3 Public Participation Process
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.		6 Resource Options
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: (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.		11.1.3.2 Load Shapes; 12 Technical Appendix Attachments Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report; Attachment 4.2 Vectren Hourly Load Data
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.		11.1.3 Overview of Past Forecasts; 12 Technical Appendix Attachments Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(3) Actual and weather normalized energy and demand levels.		11.1.3 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.		11.1.3 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.		4.6 Energy and Demand Forecast (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.		11.1.3 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.		12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report
(8) Justification for the selected forecasting methodology.		12 Technical appendix attachments 4.1 2019 Vectren Long-Term Electric Energy and 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.		1.3.3.1 Advanced Metering Infrastructure; 11.1.2 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.		7.3 Alternate Scenarios
(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.		7.3 Alternate Scenarios; 12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(10) State and federal energy policies. (11) State and federal environmental policies.		
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.		6.2 Current Resource Mix; 11.4.2 Approximate Net and Gross Dependable Capacity
(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.		6.2 Current Resource Mix
(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.		12 Technical Appendix Attachments: Confidential Attachment 8.2 Aurora Input Model Files
(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.		11.2 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;		11.8 Transmission Appendix

(ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.		
(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.		6.2.4 Energy Efficiency; 6.2.5 Demand Response; 6.3.2 DSM; 11.3 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.		6.3.2.6 Other Innovative Rate Designs
(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.		6.3.2 DSM, 12 Technical Appendix Attachments 6.2 2019 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 nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource.		6 Resource Options; 11.2 Environmental Appendix; 12 Technical Appendix Attachments: Attachment 1.2 Vectren Technology Assessment Summary Table; Confidential Attachment 8.2 Aurora Input Model Files

(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.		
(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 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.		6.4 Transmission Considerations
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.		6.6 Levelized Cost of Energy Resource Screening Analysis
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.		2.5 Portfolio Development; 8 Portfolio Development and Evaluation
(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 kilowatt-hour delivered, with the interest rate specified.		8.2 Evaluation of Portfolio Performance; 9.1.2 Affordability; 11.6.8 Affordability Ranking
(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.		6 Resource Options; 8 Portfolio Development and Evaluation; 9.1 Preferred Portfolio Recommendation

(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.		9 IRP Preferred Portfolio Recommendation
(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.		N/A
(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.		9. IRP Preferred Portfolio; 10.2.5 Ability to Finance the Preferred Portfolio, 11.3.5 Avoided Costs, 11.7.1 Affordability Ranking; 12 Technical Appendix Attachments, Confidential Attachment 8.2 Aurora Input Model Files
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.		2 Vectren's IRP Process; 5 MISO Market; 7.2 Reference Case Scenario; 7.3 Alternate Scenarios; 8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio; Confidential Attachment 8.2 Aurora Input Model Files

(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.		10.2 Discussion of Plans for the Next 3 years; 11.1.4 Advanced metering Infrastructure and Continuous Improvement
(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.		8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio
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.		10 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.		10 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.		10 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.		10.2.2 DSM

(3) The implementation schedule for the preferred resource portfolio.		10.3 Implementation Schedule for the Preferred Resource Portfolio
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.		10.2 Discussion of Plans for the Next 3 Years
(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.		10.1 Differences Between the Last Short Term Action Plan From What Transpired

List of Acronyms/Abbreviations

ABB	Power Consulting Company
ABB	A.B. Brown Generating Station
AC	Alternating Current
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ATC	Around the Clock
AUPC	Average Use Per Customer
BAGS	Broadway Avenue Generating Station
BAU	Business as Usual
BES	Bulk Electric System
BEV	Battery Electric Vehicles
BPM	Business Practice Manual
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
BYOT	Bring You Own Thermostat
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CDS	Circulating Dry Scrubber
CHP	Combined Heat and Power
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
Comm	Commercial
CONE	Cost of New Entry
COVID	Corona Virus Disease
CPCN	Certificate of Public Convenience and Necessity
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
C&I	Commercial and Industrial
DA-LSFO	Dual-Alkali FGD-Forced Oxidation
DA-LSIO	Dual-Alkali FGD-Inhibited Oxidation
DC	Direct Current
DG	Distributed Generation

List of Acronyms/Abbreviations (Cont.)

DGS	Demand General Service
DLC	Direct Load Control
DPP	Definitive Planning Phase
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM	Equipment Manufactures
EM&V	Evaluation, measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDA	Flash Dryer Absorber
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GIR	Generator Interconnection Requests
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HB	House Bill
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value

List of Acronyms/Abbreviations (Cont.)

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
ILB	Illinois Basin
IMPA	Indiana Municipal Power Agency
Ind	Industrial
IPL	Indianapolis Power and Light Company
IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
LSFO	Limestone FGD – Forced Oxidation
LTCE	Long-term Capacity Expansion
MATS	Mercury and Air Toxics Standards
MEEA	Midwest Energy Efficiency Alliance
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy and Operating Reserve Markets Tariff

List of Acronyms/Abbreviations (Cont.)

MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NAEMA	North American Energy Markets Association
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NH_3	Ammonia Scrubber
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NOPR	Notice of Proposed Rulemaking
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NRIS	Network Resource Integration Service
NTG	Net to Gross
NU	Network Upgrade
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction

List of Acronyms/Abbreviations (Cont.)

PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PTC	Production Tax Credit
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
RAN	Resource Availability and Need
Res	Residential
RF	ReliabilityFirst
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RIIA	Renewable Integration Impact Assessment
RIM	Ratepayer Impact Measure
RS	Rate Schedules
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SBS	Sodium Based Sorbents
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SDA	Spray Dryer Absorber
SEA	Senate Enrolled Act
SERC	Southeast Reliability Corporation
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STD Dev	Standard Deviation
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
ULRC	Urban Living Research Center
UPC	Use Per Customer
V	Volt

List of Acronyms/Abbreviations (Cont.)

VAR	Volt-Amp Reactance
VER	Variable Energy Resources
VFD	Variable Frequency Drive
VOM	Variable Operation and Maintenance
VVC	Vectren Corporation
WLIO	Wet Lime FGD – Inhibited Oxidation
WN	Weather Normalized
WTE	Waste to Energy

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Executive Summary (Non-Technical Summary)

I. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company's ("Vectren") 2019/2020 Integrated Resource Plan is submitted in accordance with the requirements of the Indiana Utility Regulatory Commission (IURC or Commission) and the guidance provided in the Commission's recent orders related to the preferred portfolio described in Vectren's previous 2016 Integrated Resource Plan ("IRP"). The preferred portfolio in Vectren's previous 2016 IRP contemplated replacement of some of Vectren's coal fleet by the end of 2023 with a mix of renewable, energy efficiency and gas resources while retaining other coal resources. To implement this plan, Vectren filed two cases seeking Certificates of Public Convenience and Necessity ("CPCN") to (1) own and operate a 50 MW solar project located on its system (the "Troy Solar Project"), (2) install equipment designed to achieve compliance with environmental regulations in order to continue operation of its 270 MW Culley Unit 3 beyond 2023 and construct a 700-850 MW Combined Cycle Gas Turbine ("CCGT"). The Commission approved issuance of CPCNs authorizing the construction of the Troy Solar Project and Culley Unit 3 compliance projects. The Commission order denying a CPCN for the 700-850 MW CCGT urged Vectren to:

- Focus on outcomes that reasonably minimize the potential risk of an asset becoming uneconomic in an environment of rapid technological innovation;
- Fully consider options that provide a bridge to the future;
- Utilize a request for proposals ("RFP") to determine the price and availability of renewables; and
- Consider resource diversity and alternatives that provide off ramps that would allow Vectren to react to changing circumstances.

Vectren began its 2019/2020 IRP process in April 2019 with the objective of engaging in a generation planning process responsive to the Commission's guidance and seeking input from a variety of stakeholders. As part of its 2019/2020 IRP process, Vectren's evaluation has focused on exploring all new and existing supply-side and demand side resource options to reliably serve Vectren customers over the next 20 years. While the

fundamentals of integrated resource planning were adhered to in developing the 2016 IRP, Vectren has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- Issuance of an All-Source RFP to provide current market project pricing to be utilized in IRP modeling and potential projects to pursue, particularly for renewable resources such as wind and solar;
- An exhaustive review of reasonable options that leverage existing coal resources;
- increased participation and collaboration from stakeholders on all aspects of the analysis, inputs and resource evaluation criteria, with specific considerations and responses from Vectren;
- An encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends;
- The use of a more sophisticated IRP modeling tool, Aurora, which provided several benefits (simultaneous evaluation of many resources, evaluation of portfolios on an hourly basis and consistency in modeling, including least cost long-term capacity expansion planning optimization, simulated dispatch of resources and probabilistic modeling); and
- A more robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures.

Based on this planning process and detailed analysis, Vectren has selected a preferred portfolio plan that significantly yet prudently diversifies the resource mix for its generation portfolio with the addition of significant solar and wind energy resources, the retirement or exit of four coal units, and continued investment in energy efficiency. These resources are complemented with dispatchable resources including continued operation of Culley Unit 3 and the addition of two flexible natural gas Combustion Turbines (CTs). The gas units represent a much smaller portion of Vectren's generation portfolio as compared to the 2016 IRP preferred portfolio while still providing reliable capacity and energy. The highly dispatchable and fast-ramping gas units are an important match with the significant renewable investment, enabling Vectren to maintain constant electric supply during

potentially extended periods of low output from renewable energy sources. The units ramp quickly and provide load following capability, complimenting renewable energy production, which is expected to grow throughout the MISO footprint. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by more than $320 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 67% by 2025 and 75% by 2035 when compared to 2005 levels, which helps Vectren's parent company, CenterPoint Energy, achieve its commitments to environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

Vectren's preferred resource plan reduces risk through diversification, reduces the cost to serve load over the next 20 years and provides the flexibility to continue to evaluate and respond to future needs through subsequent IRPs. The preferred portfolio has several advantages: including: 1) Energy supplied by this portfolio is generated primarily through a significant amount of near-term renewable solar and wind projects that take advantage of the Investment Tax Credit and the Production Tax Credit. This lowers portfolio costs and takes advantage of current tax-advantaged assets. 2) Two new, low-cost gas combustion turbines, continued use of Vectren's most efficient coal unit (Culley 3) and new battery storage resources, provide resilient, dispatchable power to Vectren's system that is complementary to significant investment in new intermittent renewable resources. This is very important, as coal plants, which have provided these attributes in the past, continue to retire in MISO Zone 6. 3) The portfolio provides flexibility to adapt to and perform well under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio performed well under CO_2, methane constraints, and other related regulations such as a fracking ban. The cost position of this portfolio that is backed up by the two combustion turbine capacity resources does not change because the gas turbines predominantly run during peak load conditions. This provides a financial hedge against periodic instances of high market energy and capacity prices, while also providing reactive reserves and system reliability in times of extended renewable

generation droughts, i.e., cloud cover and low wind. 4) It reasonably balances energy sales against purchases to remain poised to adapt to market shifts. 5) It includes new solar capacity when it is most economic to the portfolio. 6) Finally, it is timely. New combustion turbines can come online quickly to replace coal generation that retires by the end of 2023, minimizing in-service lag and reducing exposure to the market.

The resource options selected in this plan provide a bridge to the future. For example, CT's allow time for battery storage technology to continue to become more competitive in price and further develop longer duration storage capabilities. Further, should there be a need for new baseload generation in the future to accommodate a large load addition or to replace Warrick 4 and Culley 3, one or both CT's could be converted to a CCGT, a highly efficient gas energy resource. Even with the large commitment in the near term to renewable resources, additional renewable resources can be added over time.

The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) Vectren continues to speak with Alcoa about a possible extension of Warrick 4 (W4) joint operations through 2026. This option could provide additional time and shield Vectren customers from capacity purchases at a time where the market is expected to be tight, causing much higher projected prices than today. Additionally, time may be needed to allow Vectren to secure the level of renewable resources identified in the preferred portfolio and to allow for contingency for permitting and construction of new combustion turbines. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio will allow Vectren flexibility to evaluate this option in future IRPs. 3) Vectren will work to secure attractive renewables projects from the recent All-Source RFP but will likely require a second RFP to fully secure 700-1,000 MWs of solar on multiple sites and 300 MWs of wind constructed over a span of several years. Issuing a second RFP provides two main benefits. It allows more local renewable options to select from, as some offered proposals are no longer available. Second, it provides additional time to better understand how MISO intends to move forward with market adjustments, such as

capacity accreditation and energy price formation. MISO's wholesale market is adapting to fleet transition that is moving toward intermittent renewable resources.

What follows is a summary of Vectren's process to identify this portfolio, focusing on Vectren's operations, an explanation of the planning process and a summary of the preferred portfolio.

II. Vectren Overview

Vectren provides energy delivery services to more than 146,000 electric customers located near Evansville in Southwestern Indiana. In 2018, approximately 44% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers and 26% were made to small commercial customers.



The table below shows Vectren generating units. Since the last IRP, Vectren has formally retired four, older small natural gas units[1] rather than investing significant capital dollars to ensure safety and reliability. Note that Vectren also offers customers energy efficiency programs to help lower customer energy usage and bills.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year in Service	Unit Age	Coal Unit Environmental Controls[2]
A.B. Brown 1	245	Coal	1979	41	Yes
A.B. Brown 2	245	Coal	1986	34	Yes
F.B. Culley 2	90	Coal	1966	54	Yes
F.B. Culley 3	270	Coal	1973	47	Yes

[1] In 2018, Vectren retired BAGS 1 (50 MW). In 2019, Vectren retired Northeast 1&2 (20 MW) and BAGS2 (65 MW)

[2] All coal units are controlled for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_X), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide (SO_3) and Sulfuric Acid ($H2S0_4$) except F.B. Culley 2.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year in Service	Unit Age	Coal Unit Environmental Controls[2]
Warrick 4	150	Coal	1970	50	Yes
A.B. Brown 3	80	Gas	1991	29	
A.B. Brown 4	80	Gas	2002	18	
Blackfoot[3]	3	Landfill Gas	2009	11	
Fowler Ridge	50	Wind PPA	2010	10	
Benton County	30	Wind PPA	2007	13	
Oak Hill[4]	2	Solar	2018	<2	
Volkman Rd[5]	2	Solar	2018	<2	
Troy	50	Solar	2021		

III. Integrated Resource Plan

Every three years Vectren submits an IRP to the IURC as required by IURC rules. The IRP describes the analysis process used to evaluate the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, low cost, environmentally sustainable power over the next 20 years. The IRP can be thought of as a compass setting 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.

Vectren utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups and environmental advocacy groups. Vectren continues to place an emphasis on reliability, customer cost, risk, resource diversity, and sustainability. The IRP process has become increasingly complex in nature as renewable resources have become more cost competitive, battery energy storage has become more viable, and existing coal resources are dispatched less and less.

[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.

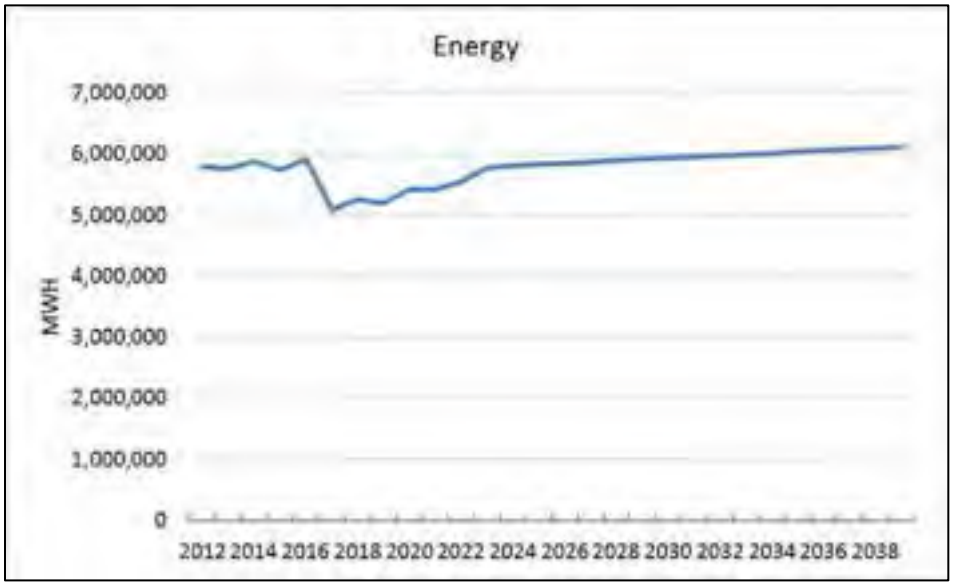
A. Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. Vectren 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. Energy is typically measured in Megawatt hours (MWh) and demand is typically measured in Megawatts (MW). Both are important considerations in the IRP. While Vectren purchases some power from the market, Vectren is required to have enough generation and energy efficiency resources available to meet expected customers' annual 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 (Midcontinent Independent System Operator) member, Vectren must comply with MISO's evolving rules to maintain reliability.

Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure that resources are available to meet this demand in all hours of the year, particularly in the times of greatest need (summer and winter). MISO functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). In recognition of MISO's ongoing evaluation of how changes in the future resource mix impact seasonal reliability, Vectren ensured that its preferred portfolio would have adequate reserve margins for meeting both the winter and summer peak demand. Later in this document it is further explained how MISO is evaluating measures to help ensure year-round reliability.

Vectren 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 demand are expected to grow by 0.6% per year. Winter demand grows at a slightly slower pace of 0.5%.





B. Resource Options

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. Vectren considered both new and existing resource options. Burns and McDonnell, a well-respected engineering firm, conducted an All-Source RFP which generated 110 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, demand response, wind, gas and coal. These project bids provided up-to-date market-based information to inform the analysis and provide actionable projects to pursue to meet customer needs in the near to midterm. Additionally, Vectren 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 coal units, conversion of coal units to natural gas, various natural gas resources, hydro, landfill gas, and long-duration batteries, as well as partnering with other load-serving entities. Every IRP is a snapshot in time producing a direction based on the best information known at the time. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: projected low stable gas prices, low cost and projected high penetration of intermittent renewable resources, future of coal resources, new technology and projected changes in the MISO market to adapt and help ensure reliability.



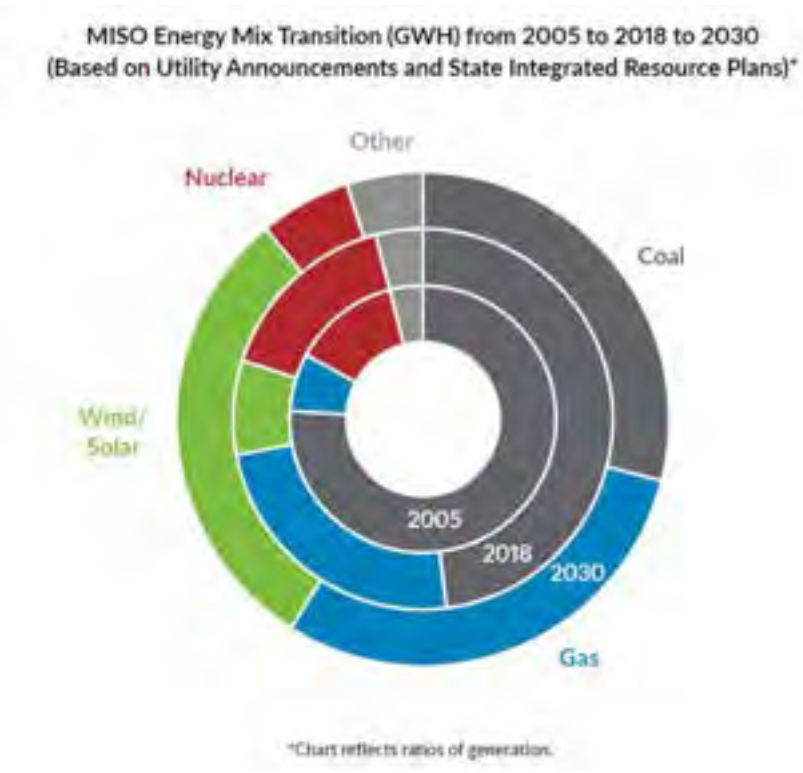
i. Industry Transition

The cost of fuel used by generation facilities to produce electricity is also accounted for in evaluating the cost of various electric supply alternatives. Gas prices are near

record low levels and are projected to remain stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices and has fueled a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to the market, as gas units are on the margin and typically set market prices for energy.

Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation, used primarily to meet the needs during peak demand conditions in 2005, to approximately 26% of total generation in 2018[6]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by government incentives in the forms of the Production Tax Credit for wind and the Investment Tax Credit (ITC) for solar, both of which are set to expire or ratchet down significantly over the next few years.

The move toward low cost renewable 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 compete on price with low cost 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



[6] MISO Forward Report, March 2019, page 10. https://cdn.misoenergy.org/MISO%20FORWARD324749.pdf

designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Additionally, older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with Environmental Protection Agency (EPA) regulations. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has driven unit retirements. Based on these and other major factors, MISO expects the generation mix in 2030 to be much more balanced than in the past with roughly one third renewables, one third gas and one third coal. Some large nuclear plants remain but have also found it challenging to compete on cost.

ii. Changing Market Rules to Help Ensure Reliability

MISO recognizes these major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level, 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 over production (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 is in the process of studying how this transition will affect the electrical grid and what is needed to maintain reliable service, as renewables penetrations reach 30-50%. Possible ramifications include challenges to the ability to maintain acceptable voltage and thermal limits on the grid.

To deal with these challenges, MISO has been working through a series of studies and has put forth guidance for how they intend to evaluate resources moving forward. One significant development is the recognition that all hours matter. In the past, MISO

resource adequacy requirements focused on only the peak hour each year. Recent MISO emergencies in all seasons have demonstrated that the system can experience potential energy shortfalls in any hour due to changing resource conditions. As such, MISO is planning for new requirements to ensure resources are available for reliability in each of the 8,760 hours of the year. Each resource has different operating characteristics and different output levels, depending on the season. Vectren has accounted for these changes by validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[7] in the two heaviest demand periods (summer/winter). MISO has initiatives underway that include new testing requirements to ensure that Demand Response (DR) resources are available when needed. MISO's annual Market Road Map process has prioritized the development of mechanisms to more accurately account for resource availability. This includes an evaluation of how to best incent resources with the right kinds of critical attributes needed to keep the system operating reliably. Incentives are contemplated for resources that are available (dispatchable), flexible (ability to start quickly and meet changing load conditions when needed) and visible (have a better understanding of customer owned generation in addition to larger utility assets). MISO expects that traditional dispatchable coal and gas resources will continue to provide resilience to the grid.

iii. Battery Storage and Transmission Resources

Increasingly, utilities are considering the opportunity to add battery storage to resource portfolios to help provide the availability, flexibility and visibility needed to move to more reliance on intermittent renewable resources. Lithium-ion batteries have seen significant cost declines over the last several years as the technology begins to mature and as the auto industry creates economies of scale by increasing production to meet the anticipated demand for electric vehicles. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives

[7] Some portfolios have a heavy reliance on the market for both energy and capacity.

are available to lower the cost of this emerging technology or for special applications that improve the economics.

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. Vectren has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project is providing information regarding the ability to store energy for use during the evening hours to meet customer energy demand. Along with the benefits provided by this technology, there are some limitations to keep in mind as utility scale battery storage is still evolving. Currently, commercially feasible batteries are short duration, typically four hours. There are some commercially available longer-duration batteries that show promise, but these are still very expensive. Additionally, safety standards are being developed and fire departments are being trained for the fire risk posed by L-ion batteries. Other chemistries are being developed to account for this issue but are not commercially imminent. Moreover, batteries today are a net energy draw on the system. They can produce about 90-95 percent of the energy that is stored in them. Part of this loss is due to the need to be well ventilated, cool and dry, which takes energy. Batteries are promising and have their place in current energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Vectren's All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources.

C. Uncertainty/Risk

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. Vectren's IRP analysis was developed to identify the best resource mix of generation and energy efficiency to serve customer energy needs over a wide range of possible future states. Vectren performed two sets of 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.

IV. Analysis

Vectren'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. Conduct an All-Source RFP to better understand resource cost and availability.
2. Work 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. Work 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. Work 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. Utilize the quantitative scorecard measures and judgement 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).



V. Stakeholder Process

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was taken to ensure that the time spent was mutually beneficial.

Each of the first three stakeholder meetings began with stakeholder feedback. Vectren would review requests since the last stakeholder meeting and provide feedback. Suggestions were taken and in instances where suggestions were not acted upon, Vectren made a point to further discuss and explain why not. Per stakeholder feedback, 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 session per request.

Three of four public stakeholder meetings were held at Vectren in Evansville, IN. The final stakeholder meeting on June 15, 2020 was held via webinar due to the COVID-19 situation. Dates and topics covered are listed below:

August 15, 2019	October 10, 2019	December 13, 2019	June 15, 2020*
• 2019/2020 IRP Process • Objectives and Measures • All-Source RFP • Environmental Update • Draft Reference Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Reference Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Scenario Testing and Probabilistic Modeling Approach and Assumptions	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

* Moved final stakeholder meeting date per stakeholder request and the COVID-19 situation

Based on this stakeholder engagement, Vectren 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. Vectren utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios (i.e. Indiana Coal Council (ICC) request to continue coal through 2029 or 2039 and environmental stakeholders' request to utilize all renewable resources by 2030). For example, the low regulatory future includes declining coal prices and higher gas prices, which was a request from the ICC. The High Regulatory scenario, which was heavily influenced by environmental stakeholders, is the other plausible future

bookend with a natural gas fracking ban (sustained high price), a social cost of carbon fee starting at $50 per ton in 2022 and lower renewables cost trajectory than what is expected. Additionally, an evaluation measure was adjusted based on direct stakeholder input. Vectren included the life cycle of carbon emissions for all resources in response to the ICC and environmental stakeholders. The table below shows key stakeholder requests made during the process and Vectren's response.

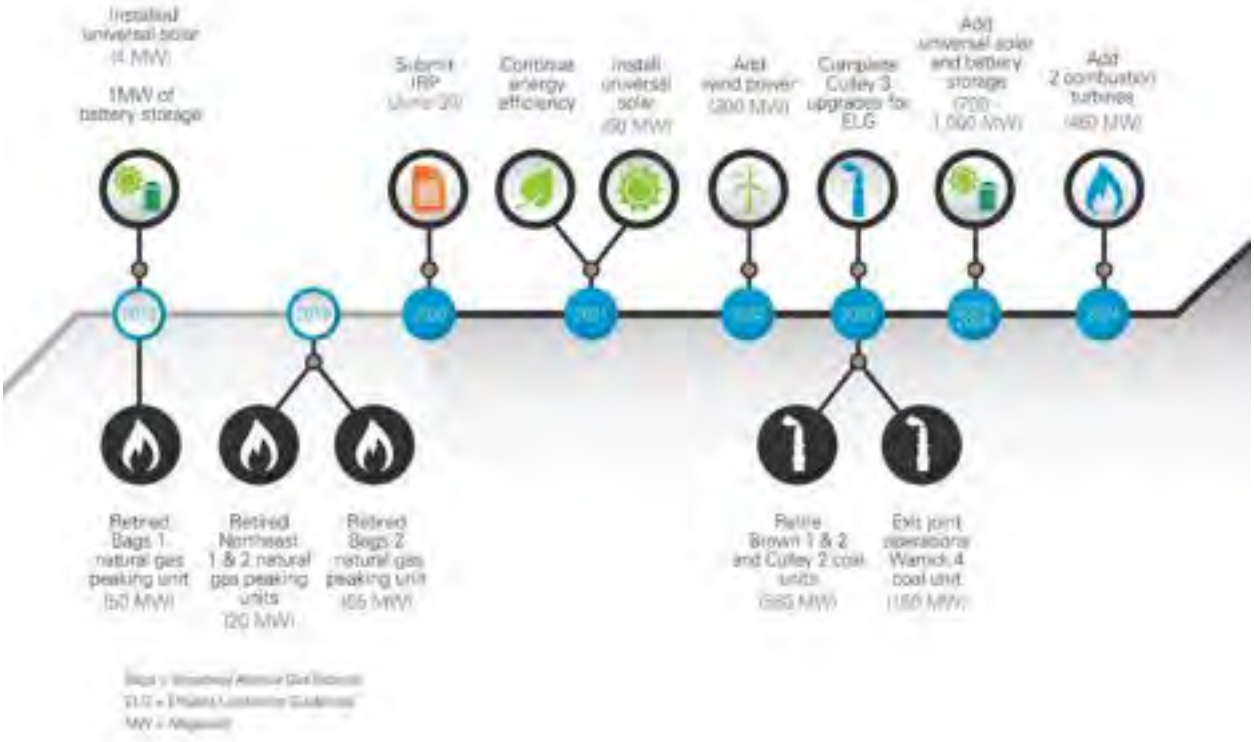
Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed a balanced impact on the load (the economic drag from a carbon fee is neutralized by the economic stimulus of a dividend)
Lower renewables costs in the High Regulatory and 80% CO_2 Reduction scenarios	Updated scenario to include lower costs for renewables and storage than the Reference scenario
Consider life cycle emissions using CO_2 equivalent	Included a quantitative measure on the risk scorecard based on National Renewable Energy Lab (NREL) Life Cycle Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers the risk that assets become uneconomic	Included an uneconomic asset risk as a consideration in the overall evaluation. Not included in the scorecard.
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price that was approximately $200 by the end of the forecast	Utilized a scenario with these prices to create an additional portfolio. Ultimately, this portfolio was not selected for the risk analysis, as the amount of generation built

Request	Response
	within modeling vastly exceeded Vectren's need and resulted in large energy sales
Reconsider the use of a seasonal construct for MISO resource accreditation	Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter
Include a CO_2 price in the reference case	Included mid-range CO_2 prices 8 years into the forecast. The Low Regulatory scenario did not include a CO_2 price, thus becoming a boundary condition

Meeting materials of each meeting can be found on www.vectren.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

VI. The Preferred Portfolio

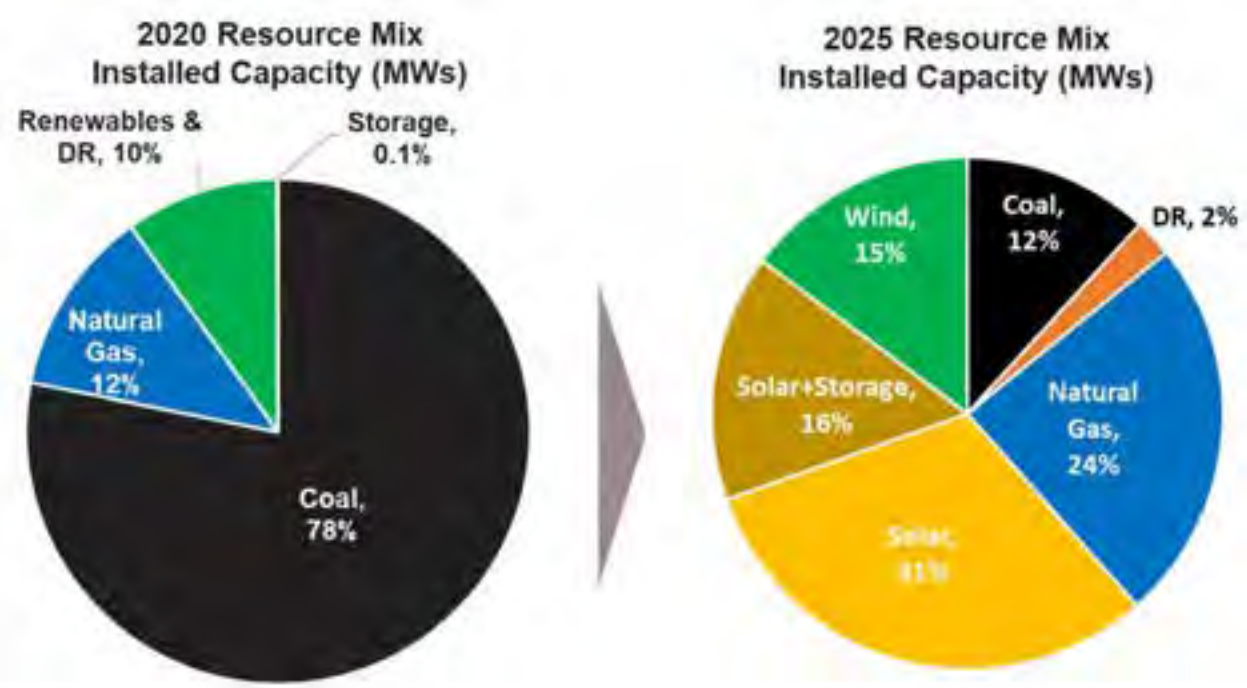
The Preferred Portfolio recommendation is to retire or exit 730 MWs of coal generation and replace with 700-1,000 MWs of solar generation (some connected to battery storage), add 300 MWs of wind backed by dispatchable generation that consists of 2 new Combustion Turbine (CT) gas units and maintaining Culley 3 (coal unit).



This preferred portfolio:

- Allows customers to enjoy the benefits of low-cost renewable energy, while ensuring continued reliable service as Vectren moves toward higher levels of intermittent renewable energy in the future.
- Saves customers over $320 million over the next 20 years when compared to continued operation of Vectren's coal fleet. The preferred portfolio is a low-cost portfolio in the near, mid and long term.
- Reduces lifecycle greenhouse gas emissions, which includes methane, by nearly 60% over the next 20 years. Direct carbon emissions are reduced 75% from 2005 levels by 2035.

- Includes a diverse mix of resources (renewables, gas and coal), mitigates the impacts of extended periods of limited renewable generation and protects against overreliance on the market for energy and capacity.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry, includes a multi-year build out of resources on several sites and maintains the option to extend the contract with Alcoa for Warrick 4 for a few years and maintains the option to consider the replacement of Culley 3 in the future when appropriate based on continual evaluation of changing conditions. These options will be revaluated in future IRPs.
- Provides the flexibility to adapt to future environmental regulations or upward shifts in fuel prices relative to Reference Case assumptions. The preferred portfolio performed consistently well across a wide range of potential future environmental regulations, including CO_2, methane and fracking.
- Adds some battery energy storage in the near term, paired with solar resources to provide clean renewable energy when solar is not available. Provides time for technological advances that will allow for high penetration of renewables across the system, further cost declines and further Vectren operational experience to meet Vectren's customers' energy needs.
- Continues Vectren's energy efficiency programs with near term energy savings of 1.25% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. Vectren is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.



VII. Next Steps

The preferred portfolio calls for Vectren to make changes to its generation fleet. Some of these changes require action in the near term. First, Vectren will finalize the selection process to secure renewable projects from the All-Source RFP and seek approval from the IURC for attractive projects. Second, the IRP calls for continuation of energy efficiency. Vectren filed a 2021-2023 plan with the IURC in June of 2020, consistent with the IRP. Third, Vectren intends to pursue two natural gas combustion turbines to provide dispatchable support to the large renewables based preferred portfolio. These filings will be consistent with the preferred portfolio. 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 plan.

Vectren's plan must be flexible; as several items are not certain at this time.

- The timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa. Without incremental investment, the plant does

not comply with the ELG and other water discharge control requirements. Vectren therefore continues to talk to Alcoa about its plans.

- The availability of attractive renewable projects is currently being evaluated. Negotiations for resources must take place to finalize availability and cost of projects. The Coronavirus has put pressure on supply chains and put in jeopardy the ability of full utilization of the Production Tax Credit and Investment Tax Credit for some projects. Competition for these projects is steep, with multiple, on-going RFP processes in the state of Indiana.
- Finally, MISO continues to evaluate the accreditation of resources. Vectren will continue to follow developments to determine the right amount of renewable resources to pursue in the near term.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren is a wholly owned subsidiary of CenterPoint Energy, Inc. On February 1, 2019, CenterPoint Energy, Inc. (NYSE: CNP) and Vectren Corporation (NYSE: VVC) completed a merger. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers.

Operation of Vectren's electric transmission and distribution services, including its power generation and wholesale power operations now fall into CenterPoint's Indiana Electric business. Vectren serves approximately 146,000 customers in Southern Indiana.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. The IRP is used as a guide for how Vectren will serve existing and future customers over the next 20 years in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and Demand Side Management (DSM) options. It is not a turn-by-turn GPS. Future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every three years and last submitted it in 2016 with a plan to transition its generation fleet away from a majority reliance on coal. Vectren began this IRP process by gathering feedback from stakeholders on the last IRP, the Final Director's Report for 2016 Integrated Resource Plans and the Indiana Utility Regulatory Commission's Order in 45052 (Vectren's 2018 generation transition filing). Additionally, Vectren worked more closely with IRP stakeholders than ever before to listen, inform and consider updates to the process, as discussed in Chapter 3 Public Participation Process.

The future is uncertain; several factors have helped to set the stage for this analysis. Gas prices remain historically low and are projected to be stable over the long term. Shale gas

has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment, due to its low-cost energy and capacity value that it brings to the grid.

Renewable costs continue to decline and are producing competitively priced energy in the Midwest region, but still require backup for times when the wind is not blowing and the sun is not shining (on a daily and seasonal basis). Based on expectations of increasing penetration of renewables, particularly solar, MISO (Midcontinent Independent System Operator), Vectren's regional transmission operator, continues to evaluate rules and mechanisms that are needed now and in the future to maintain reliability. Vectren continues to monitor developments within MISO; the outcomes of two major studies are important for resource planning. 1) MISO is conducting a Renewable Integration Impact Assessment (RIIA) related to impacts of renewable energy growth in MISO over the long term. This study will assess implications to MISO's transmission needs and ability to effectively dispatch its members' generation fleet. 2) MISO is simultaneously conducting the Resource Availability and Need (RAN) initiative, which looks at more granular planning and accreditation of generation resources to account for a changing generation mix and resulting attributes, both of which are discussed in detail below.

In order to better evaluate renewable, energy storage and energy efficiency resources within the IRP analysis, Vectren chose to move to a more sophisticated IRP modeling tool than was used in the 2016 IRP, the Aurora modeling platform. It provided several benefits: 1) simultaneous evaluation of many resources, 2) evaluation of portfolios on an hourly basis and 3) consistency in modeling, including optimization, simulated dispatch of resources and probabilistic modeling. The output from this model provides quantitative data to help evaluate portfolios within a robust risk analysis, designed to understand performance over a wide range of futures.

1.2.1 IRP Objectives

Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[8] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren's objectives are as follows:

- Safe Reliable Service (a requirement for all portfolios)
- Affordability (reflected in the balanced scorecard)
- Environmental Risk Minimization (reflected in the balanced scorecard)
- Cost Uncertainty Risk Minimization (reflected in the balanced scorecard)
- Avoiding Overreliance on Market Risk for capacity and energy (reflected in the balanced scorecard)
- Future Flexibility (reflected in both offramps and "other considerations")
- Resource Diversity (reflected in "other considerations")
- System Flexibility (operational flexibility to back up renewable resources)

1.2.2 IRP Development

As mentioned above, Vectren incorporated feedback from IRP stakeholders, IURC staff and the Commission in developing the 2019/2020 IRP. Detailed feedback was provided to IRP stakeholders on August 15, 2019, in Vectren's first of four public stakeholder meetings in a presentation titled "2019/2020 IRP Process." This presentation provided the backdrop for several Vectren commitments to improve and strengthen the analysis, most notably with the addition of an All-Source RFP, but also other improvements, including but not limited to the following:

- Additional stakeholder input,
- More consistency in modeling,
- More comprehensive analysis and

[8] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

- The evaluation of a wider mix of resources, including an exhaustive evaluation of existing resources.

Vectren worked closely with industry experts to develop a comprehensive analysis. Burns and McDonnell, now known as 1828 and Company, managed all aspects of the All-Source RFP. This analysis was utilized to provide current market pricing for resources and an opportunity for Vectren to pursue individual projects to help serve Vectren customers following the conclusion of the IRP. Pace Global, now known as Siemens Energy Business Advisory, worked with Vectren to conduct scenario development, modeling and a comprehensive risk analysis, which included both scenario based and probabilistic modeling.

1.3 CHANGES SINCE THE 2016 IRP

Several developments have occurred since the last IRP was submitted in 2016, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information at a point in time. The following sections discuss some of the major changes that have occurred over the last three years. Vectren realizes that conditions will change, and tis analysis was designed to test portfolios under a wide range of plausible futures.

1.3.1 Generation and Storage Filings

1.3.1.1 Generation Transition Plan

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient, large, natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. This was done through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved. The following concerns were raised in opposition to the proposal:

- Vectren selected a Combined Cycle Gas Turbine (CCGT) that was too large for a small utility
    - Did not adequately consider flexibility to change paths, adding stranded asset risks
    - Did not consider fuel or geographic diversity
- Risk analysis did not consider the full range of portfolios
    - Did not fully explore options at the Brown plant (conversion or scrubber alternatives)
    - Need to more fully consider customer-generator opportunities
    - Did not fully consider energy and capacity purchases
    - Did not consider smaller gas plant options in the risk analysis
- Vectren's analysis disadvantaged renewable resources
    - Vectren did not make a serious effort to determine the price and availability of renewables
    - The RFP was too restrictive
- Vectren did not fully respond to the Director's report critiques in updated CPCN analysis
    - Did not update the risk modeling
    - Did not consider the full range of gas prices (including methane regulation)

Each of these concerns is addressed in detail within this IRP analysis and selection of the preferred portfolio. All will be addressed in detail within this report.

1.3.1.2 Urban Living Research Center (ULRC)

Vectren has partnered with Scannell to develop the Urban Living Research Center (ULRC), a living laboratory facility which will serve as a leading-edge research vehicle for Vectren to better understand and partner with customers. The ULRC is part of a larger, mixed-use, multifamily development called the “Post House” which opened on June 1, 2020. The Post House/ ULRC originated as a partnership in response to the Regional Cities Initiative, which aims to retain and attract talent by enhancing the quality of Indiana communities. The ULRC will include a mix of natural gas and electric, efficient and smart energy-using devices, such as lighting, HVAC, water heating and instrumentation, that will help the Company research new products and services to help customers manage their energy use. The Company was awarded funding from the Department of Energy’s Building Technologies Office to utilize toward the ULRC to advance research in grid-interactive buildings in partnership with Oak Ridge National Laboratory. Based on actual construction of the facility and the available rooftop space, Vectren plans to install rooftop solar. Lithium-ion battery storage in both front- and behind-the-meter configurations was also planned for the facility but was removed from the project due to concerns related to the placement of Lithium-ion batteries indoors in light of evolving safety standards and best practices. Lessons learned and data from this project could help future integrated resource planning efforts.

1.3.1.3 Volkman and Oak Hill Universal Solar and Battery Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

1.3.2 Environmental Rules

1.3.2.1 Rules Update

1.3.2.1.1 Air

In March 2015, USEPA entered into a consent decree to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO2) National Ambient Air Quality Standard (NAAQS) designations. The agreement required USEPA to designate as nonattainment, attainment or unclassifiable, certain areas that included sources that emitted more than 16,000 tons of SO2 in 2012 or emitted more than 2,600 tons of SO2 with an average emission rate greater than 0.45 lbs./MMBtu. USEPA identified five sources in Indiana that exceeded this threshold, including the A. B. Brown plant. In order for Posey County to meet the attainment designation, Vectren had to agree to a lower SO2 emission rate for the A.B. Brown plant. Vectren worked with IDEM and accepted a Commissioner's Order to voluntarily lower the plant's SO2 emission limit, which went into effect April 19, 2016.

EPA finalized the Affordable Clean Energy rule (ACE) repealing and replacing the Clean Power Plan in June 2019. The ACE rule established carbon dioxide (CO_2) emission guidelines for states to use when developing plans to limit CO_2 at coal-fired electric generating units (EGUs) within the state. ACE established heat rate improvement, or efficiency improvement, as the Best System of Emissions Reductions (BSER) for CO_2 from coal-fired Electric Generating Units (EGUs). States were given six candidate technologies to be considered as BSER along with their calculated efficiency improvements and costs to implement and operate. States are to establish unit-specific standards of performance that reflect the emission limitation achievable through application of the BSER technologies with consideration of "the remaining useful life of the source" and other source-specific factors. State Implementation Plans are due July 2022 with compliance planned to begin within 24 months of submission.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the F. B. Culley and A. B. Brown plants. The negotiated settlement required Vectren to eliminate the scrubber bypass stack for F. B. Culley Unit 2 and install equipment to mitigate SO3 emissions from A. B. Brown Units 1 and 2 and F. B Culley Unit 3. Each unit is required to maintain a H2SO4 emission limit to demonstrate compliance.

The state of Indiana has developed a state implementation plan (SIP) to administer the three trading programs under the Cross-State Air Pollution Rule (CSAPR) and allocate allowances for affected electric generating unit starting in 2021. The SIP was published in the Federal Register on December 17, 2018. The intent of CSAPR is to address power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states.

1.3.2.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology-based limits for waste waters generated from fossil fuel fired generating facilities and, will force significant operational and technological changes at coal fired power plants. EPA finalized the rule with a hybrid of the most stringent of the proposed options for fly ash transport water, bottom ash transport waters and FGD waste waters.

While the 2015 final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste waters and ash transport waters. Specifically, FGD waste waters must meet new limits for arsenic, mercury, selenium and nitrate / nitrite at the end of the wastewater treatment system and prior to mixing with any other process waters. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity, which effectively forces the installation of dry or closed loop ash handling systems. In September 2017, the ELG Postponement Rule was published. The

Postponement Rule delayed the applicability date for the Bottom Ash Transport Waters from November 1, 2018 to November 1, 2020, but the no later than December 31, 2023 date for completion remained in place.

The A.B. Brown and F.B. Culley NPDES permits were renewed in 2017 and have since been modified as appropriate to allow for the BATW date extension allowed by the ELG Postponement Rule. As required by the ELG Rule and consequently the NPDES permits, FBC has ceased the discharge of FATW and will complete the conversion of bottom ash to a dry system in fall 2020. For FGD waste waters at F.B. Culley, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD wastewater. The A.B. Brown permit was modified following publication of the ELG Postponement Rule. Currently, A.B. Brown is required to stop discharging both Fly Ash Transport Water and Bottom Ash Transport Water by November 2021. An additional ELG reconsideration rule, proposed in 2019, maintained the prohibition on the discharge of fly ash transport water and prohibits the discharge of bottom ash transport water, except in limited, specific circumstances, such as significant storm events.

1.3.2.1.3 Waste

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The “Phase 1, Part 1” rule was published on July 30, 2018 and became effective on August 28, 2018. This rule delayed the deadline by which facilities must cease the placement of waste in a CCR surface impoundment in cases where the CCR unit fails to

meet the aquifer location restriction and in cases where a CCR unit demonstrates an exceedance of a groundwater protection standard. The regulatory deadlines that currently present a scenario that could trigger the closure of Vectren surface impoundments include exceedance of ground water protection standards (triggering closure in October 2020), or failure to demonstrate compliance with location restrictions (triggering closure in October 2020). Environmental groups challenged the final "Phase 1, Part 1" rule in the D.C. Circuit Court. Additionally, in August 2018, the D. C. Circuit Court issued a decision in USWAG v. EPA, finding that the administrative record showed that all unlined impoundments pose a reasonable probability of adverse effects to human health and the environment and must be required to close. EPA filed a motion to remand the Phase 1, Part 1 rule and is currently working on rulemakings to implement the D.C. Circuit's decision. The "Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure" proposed rule provides an option for utilities to submit a demonstration (application) for surface impoundments to remain active beyond the current rule closure dates, however no longer than October 15, 2023.

1.3.2.2 Retrofitting Culley 3 to Comply with ELG

In accordance with the order of the IURC in Cause No. 45052 approving the planned activities necessary to continue to operate Culley 3 in compliance with the ELG and CCR rules, the bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

1.3.2.3 Closing Coal Ash Ponds

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive contact storm water from various areas of the plant. The construction of this pond, along with the installation

of the dry bottom ash and FGD ZLD technologies will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

1.3.3 Electric TDSIC

The IURC approved Vectren's seven-year infrastructure improvement plan for the period of 2018-2024 (Cause No. 44910). This plan helps to build/rebuild high–voltage transmission lines, replaces substation transformers, rebuilds electric circuits and includes distribution automation. These improvements will help Vectren to continue to reliably deliver power to its customers now and in the future. Additionally, these improvements, will allow more flexibility in resource planning by improving power flows across Vectren's system, particularly the addition of the East-West transmission line that will connect the F.B. Culley Plant site on the east side of the system with the A.B. Brown plant site on the west side.

1.3.3.1 Advanced Metering Infrastructure (AMI)

In 2017, Vectren began installation of AMI smart meters as a key part of Vectren's grid modernization plan. Vectren has since successfully installed meters across its territory. AMI provides access to much more granular customer load data and will help Vectren to better understand and anticipate changes in an evolving energy landscape. This improvement will have long-term benefits for load research and long-term load forecasting, as well as provide the opportunity to create innovative DSM programs for shaping customer load. Vectren customers have already received many benefits in the near term for billing, quicker service response time and quicker responses to power outages; however, the long-term benefits will take time and have not been fully realized by the compilation of this IRP.

1.3.4 IRP Rule Making Process

Revisions to Integrated Resource Planning were made via RM# 11-07, which began in 2010. Vectren voluntarily followed the draft rule in 2014 and 2016 IRPs, which included a public stakeholder process. In 2019 the rule was finalized and can be found in the IRP Rule Requirements Cross reference table of this document. Major updates to the rule included moving from a two year to three-year cycle and several updates to the stakeholder process, including the number of required stakeholder meetings, which is now three.

1.3.5 DSM Filing

On April 10, 2017, Vectren filed with the Indiana Utility Regulatory Commission (IURC) a Petition seeking approval of Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 Plan or Plan). The Plan included proposed energy efficiency goals; program budgets and costs; and procedures for independent evaluation, measurement and verification (EM&V) of programs included in the Plan. The Plan has an estimated cost of $28.6 million, with $9.5 million in 2018, $9.6 million in 2019 and $9.5 million in 2020. The Plan includes a portfolio of programs designed to achieve 111 million kWh in energy savings and 26,000 KW in demand reduction during the three-year period.

On December 28, 2017, the IURC issued an Order approving Vectren’s 2018-2020 Energy Efficiency Plan (2018-2020 EE Plan) pursuant to Section 10. Vectren carried out a lengthy analysis of the DSM resources included in its IRP process. The Commission found that the proposed energy savings goals appear reasonably achievable and consistent with historical savings that has been previously approved. A summary of the savings and budgets are listed in the table below.

Figure 1.1 – 2018-2020 Portfolio Summary of Participation, Impacts, & Budget

Portfolio Participation, Impacts & Budget								
Program Year	Participants /Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Res & C&I Direct Program Budget	Indirect Portfolio Level Budget	Other Costs Budget	Portfolio Total Budget Including Indirect & Other	First Year Cost/kWh *
2018	334,626	36,656,341	7,430	$ 8,050,391	$ 937,436	$ 500,000	$ 9,487,827	$ 0.23
2019	354,120	38,069,188	7,607	$ 8,433,276	$ 960,110	$ 200,000	$ 9,593,386	$ 0.23
2020	225,065	36,347,642	7,750	$ 8,370,366	$ 960,225	$ 200,000	$ 9,530,591	$ 0.24

* Cost per kWh includes program and indirect costs for budget. First year costs are calculated by dividing total cost by total savings and do not include carryforward costs related to smart thermostats, BYOT and CVR program.

1.3.6 Alcoa Contract

Alcoa and Vectren have jointly owned and operated the 300 MW Warrick 4 unit since 1970. In 2016, Alcoa split into two separate public companies and Alcoa Inc., as owner of the Warrick site, closed the aluminum smelter and greatly reduced load at the Warrick site. Alcoa also issued notice to Vectren that it would terminate and exit the joint operations of Warrick 4. However, Alcoa later reopened the smelter. After filing the 2016 IRP, Vectren worked with Alcoa to extend joint operations of Warrick unit 4 until December 31, 2023. The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Alcoa's power plant provides most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being most of that demand. Alcoa's interest in continuing to operate the jointly owned Warrick 4 is unclear. As Vectren sought to maintain flexibility in this IRP, the company approached Alcoa to see if there was any potential to continue jointly operating Warrick 4 beyond 2023. Alcoa commented that it would possibly consider jointly operating the unit for an additional three years. While there is no commitment to run past 2023, Vectren included a three-year Warrick 4 extension possibility within the IRP modeling analysis as an option to maintain flexibility. Part of Alcoa's evaluation of the future of Warrick 4 is the potential need to invest in environmental control upgrades to continue operating the unit beyond 2023.

1.3.7 Merger with CenterPoint Energy

On February 1, 2019, CenterPoint announced the successful completion of the merger between Vectren and CenterPoint. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers. These utilities consist of the following:

- Electric utility business – CenterPoint Energy maintains wires, poles and electric infrastructure serving 2.4 million metered customers in the greater Houston area and 146,000 customers in Indiana. The company also owns and operates approximately 1,200 megawatts of power generation capacity in Indiana. CenterPoint Energy's Texas electric utility business is headquartered in Houston and its Indiana electric utility business is headquartered in Evansville, Ind.
- Natural gas utility business – CenterPoint Energy sells and delivers natural gas to 4.5 million homes and businesses in eight states: Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma and Texas, including the high-growth areas of Houston and Minneapolis. The company's natural gas utility business is headquartered in Evansville.

1.3.8 FERC Grid Resilience and MISO Initiatives

Grid resilience became a national topic of interest in 2017 when the Department of Energy issued a Notice of Proposed Rulemaking (NOPR) for the Federal Energy Regulatory Commission’s (FERC) consideration. The basis of the NOPR was that due to the large amounts of retiring dispatchable generation, namely nuclear and coal, the nation’s bulk electric system was susceptible to power interruptions during extreme events and that it would be ill-suited to recover from these events. In January of 2018, FERC terminated the NOPR and directed each regional transmission owner (RTO) to evaluate its own resiliency, defined as the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or

rapidly recover from such an event. MISO, the RTO that Vectren is a member of, filed comments to FERC stating its grid is resilient due to its robust electric and gas transmission infrastructure and its diverse generator makeup that spans a region from Ontario to the Gulf Coast. Furthermore, MISO stated footprint diversity is a staple of MISO's annual Value Proposition and is the cornerstone that MISO points to that ensures resiliency. MISO also noted several areas in which it would focus efforts to ensure continued resilience, namely through transmission planning, best in class technological tools and engagement with state and local regulators to assist in measurement and planning for local systems that may be vulnerable to high-impact events.

MISO's Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) are the two current methods in which it is dealing with its evolving grid to help keep the system resilient and reliable. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them.

1.3.8.1 MISO Resource Availability and Need (RAN)

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, in 2018 MISO implemented its Resource Availability and Need (RAN) initiative. The goal of this initiative is "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region[9]."

[9] MISO Resource Availability and Need Issue Summary: page 1, January 12, 2018 https://www.misoenergy.org/api/documents/getbymediaId/96780

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[10] that are high priority, including:

- Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events,
- Increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold and
- a Seasonal Planning Resource Auction construct, which could break up the current annual capacity auction into seasons (winter and summer auctions) that would adjust the PRMR and capacity accreditation for resources during these periods. This initiative is in the primary phase of stakeholder vetting, with a possibility of tariff revisions submitted next year and could be in effect as early as the 2022-23 Planning Year.

1.3.8.2 MISO Renewable Integration Impact Assessment (RIIA)

With increased levels of intermittent renewable generation, operating the grid becomes increasingly more complex. To help understand what is needed in the long term to deal with this complexity, in 2017 MISO launched its Renewable Integration Impact Assessment (RIIA) study to find system integration inflection points. In other words, to find out where there may be potential issues as renewable penetration increases from 10%, 20%, 30% or beyond. MISO is focusing on a few key areas: Resource Adequacy, Energy Adequacy and Operating Reliability. As discussed further in this document, the resource adequacy portion of the analysis has already yielded actionable insights into integrated resource planning, which have been incorporated into Vectren's 2019/2020 analysis, particularly the amount of capacity that will likely be accredited to wind and solar resources over time based on penetration rate and expected output under peak

[10] MISO Market Roadmap, February 2019: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

conditions. MISO calls this Effective Load Carrying Capability (ELCC). This study illustrates the need for dispatchable resources that support high renewable penetrations as the peak load, net of renewable generation, pushes farther into the evening after the sun goes down. Flexible, dispatchable resources are needed to meet this need quickly.

1.3.9 2016 IRP Director's Report

Each year, the Director to the IURC electric division issues a critique of IRPs. The 2016 IRP Director's report listed a balance of positive comments, coupled with improvement opportunities for Vectren. The table below shows the improvement opportunities with a brief description of how the comment was addressed within the 2019/2020 IRP:

Figure 1.2 – IRP Improvements Based on 2016 IRP Director's Report

Improvement Opportunities	Addressed
Include lower and higher boundary scenarios to create a wider range of portfolios	A wider range of forecasts were considered for key inputs within scenario development
Model a wide range of portfolios	Vectren modeled 10 portfolios in the risk analysis, utilizing feedback from multiple stakeholders to ensure many potential paths were covered, from continue most coal to all renewables by 2030
Strategist model did not consider enough options simultaneously	Utilized Aurora, which did consider all resources simultaneously
Update risk analysis methodology to be less qualitative and more encompassing of known risks. Clearly define risk analysis methodology	Included known risks within scenario development and the risk analysis, including, but not limited to CO_2 cost, potential methane regulations, possible

Improvement Opportunities	Addressed
	shale gas ban, uneconomic asset risk, etc.
Explore other options for modeling EE cost options and make greater use of a Market Potential Study (MPS) and Clearly define Energy Efficiency Methodology	Worked closely with stakeholders throughout the development process to develop EE modeling inputs using the latest MPS
More consideration given to Warrick unit 4 in scenario development	Warrick unit 4 extension (3 year) was considered within scenario optimizations. Discussions with Alcoa continue

1.3.10 Statewide Energy Policy Analysis

In 2019 the General Assembly created a task force to develop energy policy recommendations, and at this time, that work is ongoing.

The 21st Energy Policy Development Task Force was created by HEA 1278 (2019) to develop recommendations for the General Assembly and the Governor on the following:

1. Outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes.
2. Whether existing state policy and statutes enable state regulators to properly consider the statewide impact of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts.
3. How to maintain reliable, resilient and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies.

In order to arrive at its recommendations, the task force will examine existing policies and how shifts in generation portfolios may impact system reliability, grid resiliency and affordability of electric service. The task force will issue its recommendations by December 1, 2020. Any outcomes that require statutory changes will likely be proposed in the 2021 legislative session.

Additionally, HEA 1278 passed in 2019 and required the IURC to conduct a statewide analysis of impacts of transitions in fuel sources and other electric generation resources, as well as the impacts of new and emerging technologies on electric generation and distribution infrastructure, electric generation capacity, system reliability, system resilience and the cost of electric utility service for consumers. IURC staff is working with Laurence Berkeley National Lab, Indiana University and the State Utility Forecasting Group. Results will be available this summer to help inform the 21st Energy Policy Development Taskforce.

Vectren stands ready to act as a resource to members of the 21st Energy Policy Development Task Force as progress is monitored. To this point, task force meetings have served as information-gathering sessions on various topics related to electric generation and delivery. Following the conclusion of the task force's work, Vectren will work collaboratively with policymakers and all stakeholders to help ensure a bright energy future for the State of Indiana.

1.3.11 HB 1414

The Indiana General Assembly passed legislation pertaining to electric generation during the 2020 legislation session. HEA 1414 Electric Generation was signed into law by Governor Holcomb on March 21, 2020 and provides the following:

- A public utility that owns and operates a reliable capacity electric generation resource must operate and maintain the unit using good utility practices and in a manner reasonably intended to support the availability of the unit for dispatch

- The bill sets parameters around a public utility's decision to retire, sell or transfer a reliable capacity resource with a capacity of at least 80 megawatts before May 1, 2021:
    - The utility must first provide written notice of its intent to do so to the IURC
    - The IURC must conduct a public hearing to receive information and issue analysis and conclusions, after which the utility may proceed, if doing so aligns with the preferred portfolio in its most recent IRP
    - If the planned retirement, sale or transfer was not included in the most recent IRP, the utility may not proceed for at least six months from the date of the commission's receipt of the written notice
    - If the utility cites a federal mandate as the basis for the planned retirement, sale, or transfer of the reliable capacity resource, the IURC may consider the status of the mandate in its analysis and conclusions.

Passage of HEA 1414 did not impact the selection of the preferred portfolio. The timing of Vectren's IRP is such that no retirements of electric generating stations could take place before the May 1, 2021 date in the legislation.

1.3.12 COVID-19

COVID-19, the disease caused by the coronavirus, has led to unprecedented changes in the energy industry as it has affected every aspect of life. The energy industry has seen demand drop since March of 2020, on average 6-10%, while commodity prices have decreased at a steep rate. This recent pandemic is still underway as of the writing of this document and the effects and duration are still largely unknown. The scenarios in this IRP account for a range of outcomes and the Low Load scenario is illustrative of the effects from a wholesale market pricing perspective. The following sections are independent of COVID-19 as the studies were performed prior to its onset and constitute resource planning for a 20-year period. The preferred portfolio includes multiple off-ramps, which help mitigate the risk that demand does not grow to pre-Covid-19 levels.

1.3.13 Contemporary Issues

Vectren participates in the Commission's IRP Contemporary Issues Technical Conference held each year. In 2019, the Conference was held on April 15, 2019. The Conference also covered topics such as database management, integration of DERs, incorporation of load shapes into planning, the changing availability and flexibility requirements of MISO Resource Availability and Need (RAN) initiative, long-term utility planning assumptions and procurement decisions, preliminary lessons learned from NIPSCO's all-source RFP, risk analysis and life cycle analysis of greenhouse gas emissions.

Several of these topics were timely and influential within Vectren's analysis. For example, the MISO RAN discussion, which included and expected focus on resource availability and flexibility to meet daily and variable energy needs, as well as a need for a holistic solution for seasonal resource adequacy. NIPSCO's discussion of All-Source RFP and lessons learned for the IRP was helpful as Vectren conducted its first All-Source RFP for this analysis. Finally, EVA's discussion on the need for Life Cycle Analysis (LCA) of carbon emissions analysis influenced Vectren's decision to include a life cycle greenhouse gas emissions variable within the risk scorecard.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2019/2020 IRP followed a very structured, comprehensive process over a 14-month period with extensive risk-based analysis and included an All-Source RFP to include market-based pricing with the opportunity to secure available resources following the conclusion of the IRP. This process was designed to ensure that relevant technologies were evaluated and the resulting portfolio combinations were tested in a wide range of future market and regulatory conditions. The process followed is illustrated below.

Figure 2.1 – Vectren IRP Process



The following sections describe each step in the analysis.

2.2 Conduct an All-Source RFP

Vectren issued an All-Source Request for Proposals (RFP) seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. Long term resource planning requires addressing risks and uncertainties

created by several factors including the costs associated with new resources. As part of ongoing resource planning, Vectren concluded that it was in the best interest of its customers to seek information regarding the potential to acquire, construct, or contract for additional capacity that qualifies as a MISO internal resource (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS) to MISO LRZ 6. These requirements helped to provide price certainty, transparency and MISO Local Clearing Requirement (LCR) accreditation, that will be discussed in further detail.

Within the context of the 2019/2020 IRP process, Vectren used an All-Source RFP to solicit bids for supply-side and demand-side capacity resources. The purpose of the RFP was to identify viable resources available to Vectren in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources and prior to the 2019/2020 IRP, there was a potential capacity need of approximately 700 MW of accredited capacity beginning in the 2023/2024 planning year. Vectren sought flexibility when defining potential resource combinations and encouraged RFP respondents to offer available projects with less than, or more than, 700 MW. Vectren also considered alternative timelines related to the capacity acquisition to the extent Respondents were able to provide more competitive pricing and/or terms for delivery beginning prior to or after the 2023/2024 planning year. Vectren used aggregated data from the RFP responses as inputs into the IRP modeling. The RFP Proposal evaluation process was based upon the specific resource needs identified through this IRP modeling as well as the Proposal evaluation criteria. Through this RFP, Vectren sought to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand response (DRs), renewables, stand-alone and paired storage and contractual arrangements.

In connection with this RFP, Vectren retained the services of an independent third-party consultant, Burns & McDonnell, to manage the entire RFP process and work with Vectren to perform the quantitative and qualitative evaluations of all Proposals.

All Respondents were directed to interface with Burns & McDonnell for all communications including questions, RFP clarification issues and RFP Proposal submittal until late in the evaluation process.

Proposals were initially reviewed for completeness by Burns & McDonnell. Respondents were contacted for additional data or clarifications by Burns & McDonnell via a designated Vectren RFP e-mail address, VectrenRFP@burnsmcd.com. Each complete Proposal was evaluated based on the Levelized Cost of Energy (LCOE), energy settlement location, interconnection/development status & local clearing requirement and project risk factors. The evaluation criteria were intended to relatively compare each Proposal to analogous submissions. This evaluation, in conjunction with the IRP, was used to determine which combination of resources are most capable of providing Vectren customers with a safe, reliable and affordable power supply.

2.3 OBJECTIVES, RISK PERSPECTIVES and SCORECARD DEVELOPMENT

Vectren's IRP process is designed to assure a systematic and comprehensive planning analysis to determine the "preferred portfolio" that best meets all its objectives over a wide range of market futures. This process results in a reliable and efficient approach to securing future resources to meet the energy needs for Vectren customers.

In addition, the IRP process complies with environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions. In the IRP, Vectren also focused on increasing the diversification of its supply sources. As part of the IRP, Vectren considered maintaining flexibility to respond to market changes. The evaluation considered both existing and new resources, including renewable energy and battery storage options.

Economic modeling is an important part of the IRP process, as it allows Vectren to identify the portfolio of supply-side and demand-side resources on a competitive economic basis.

The resulting least cost portfolios reflect a combination of market, regulatory or technology specified conditions and market input parameters (for example, identify the least cost portfolio consisting of all renewables by 2030 using reference case market forecasts). While cost is an important objective, it is by no means the only objective. Vectren has several important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Moreover, Vectren needs to account for operational and logistical considerations in the construction of alternative portfolios to ensure that they meet minimum reliability or resource adequacy considerations.

Vectren's IRP strategy is designed to accommodate ongoing changes and uncertainties in the market. Vectren's IRP objectives are based on the need for a resource strategy that provides long term value to its customers and communities. Therefore, as objectives are evaluated, tradeoffs must be considered. Specifically, Vectren's IRP objectives are as follows:

- Reliability: As new technologies proliferate and older baseload units retire, it is apparent that there will be increased reliance on intermittent, renewable energy resources. The ability to support local system stability and reliably provide power must be maintained by meeting MISO and NERC standards for reserve margins and resource adequacy.

Quantitative Metrics Directly Considered

- Affordability: Provide all customers with an affordable supply of energy
- Cost Uncertainty Risk Mitigation: Provide a predictable, balanced and diverse mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Environmental Emission Risk Mitigation: Provide environmentally responsible power, leading to a low carbon future.
- Market Risk Minimization: Develop a flexible plan that can adapt to market conditions and regulatory and technological change to minimize risk to Vectren

customers and shareholders. The plan considers several alternative options for existing resources.

Other Considerations

- Future Flexibility: Mitigate the risk that assets in the portfolio may become uneconomic in the future through off ramps and optionality.
- Resource Diversity: Mitigate risk to customers of over-reliance on a single technology by providing a mix resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed.
- System Flexibility: Operationally able to meet the current and future needs of the evolving grid

Reliability is Vectren's priority over all other objectives. While the IRP doesn't directly assess system stability issues, all portfolios must meet minimum reserve margin and resource adequacy requirements set by MISO. These are minimum requirements met in the modeling rather than a metric tracked for each portfolio. Vectren did a reliability assessment for portfolios that made it through the screening process. This is described in Section 6.4.3 Transmission Facilities as a Resource.

The next several objectives are given one or more defined and measurable metrics. By testing candidate portfolios against these metrics, Vectren illustrates tradeoffs among competing IRP objectives. This tool aided in the selection of the preferred portfolio. The last three objectives are more subjective in nature but relevant to the IRP process so are discussed under "other considerations". The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Scorecard for IRP Objectives and Risk Metrics

	Objective	Metric
Quantitative and Qualitative (considered outside of scorecard)	Reliability	• Reliability Assessment
Quantitative Scorecard Measure	Affordability	• Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
	Cost Uncertainty Risk Minimization	• 95th percentile[11] of NPVRR (million$) across 200 dispatch iterations under varying market conditions
	Environmental Emissions	• Reduction in tons of life-cycle greenhouse gas emissions (CO_2e) 2019-2039
	Avoiding Overreliance on Market Risk	• Annual Energy Sales and Purchases, divided by Annual Generation, average (%) • Annual Capacity Sales and Purchases, divided by Total Resources, average (%)
Qualitative (considered outside of scorecard)	Resource Diversity	• Risk of overreliance on one type of resource
	System Flexibility	• Ability operationally to support the system to maintain stability and reliability
	Future Flexibility	• Risk that assets in a portfolio may become uneconomic

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each

portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with low expected costs may increase exposure to market risk. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances. Portfolio selection is based on Vectren evaluating all qualitative and quantitative metrics and using well-informed judgement in selecting its preferred portfolio. A further description of each metric is provided below.

2.3.1 Objectives and Risk Perspectives

The IRP objectives were evaluated using the results of the scenario, sensitivity and probabilistic modeling, as well as other qualitative factors.

2.3.2 Scorecard Metrics

The Balanced Scorecard is a broad comparison of candidate portfolio attributes and risks. It was populated with metrics entirely derived from the probabilistic modeling. The probabilistic modeling subjected each portfolio to 200 iterations of the dispatch model under varying market conditions. Vectren then used the resulting performance data and the distributions from the 200 iterations to quantify the metrics that align with each IRP objective. The Balanced Scorecard metrics are the same as the risk metrics described in Figure 2.2.

2.3.2.1 Affordability

For the Affordability objective, the metric used is the mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR), expressed in millions of dollars. The NPVRR is a measure of all generation related costs (for each asset, the cost of generation – capital, O&M, fuel and related transmission costs to deliver power to Vectren customers, plus the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment.

In this way, very different portfolios can be compared on a common metric or value over a long-time frame.

2.3.2.2 Cost Uncertainty Risk Mitigation

For the Cost Uncertainty Risk Mitigation objective, the metric used is the 95th percentile of NPVRR, also expressed in millions of dollars. After each portfolio was subjected to 200 dispatch model runs, a distribution is created of the NPVRR portfolio costs. The 95th percentile (approximately two standard deviations above the mean value) is a commonly used benchmark to demonstrate a reasonable upper threshold of cost risk under widely varying market circumstances.

2.3.2.3 Environmental Emission Risk Minimization

For the Environmental Emission Risk Minimization objective, the metric estimated life cycle greenhouse gas emissions of each generation type, measured in tons of carbon dioxide equivalent (CO_2e). The use of life cycle emissions rather than direct generation emissions was a result of feedback from the stakeholder process. Life cycle emissions account for "cradle to grave" emission impacts of generation and offer more consistent comparisons of environmental impact across generation technologies. The lifecycle emissions captures upstream emissions including raw material extraction, power generation facility construction and any upstream emissions associated with fuel extraction and transportation (if applicable). Life cycle emissions were estimated using the National Renewable Energy Laboratory's (NREL's) harmonized life cycle emissions factors for generation technologies considered in the analysis.[12] Life cycle emissions from existing and new resources are derived by multiplying the generation from each fuel type (including coal, gas combustion turbine, gas combined cycle, utility-scale solar and solar distributed generation and onshore wind) by the corresponding specific technology

[12] NREL conducted a systematic review of 2,100 life cycle greenhouse gas emissions studies for electricity generating technologies and screened down the list to about 300 credible references. From these, NREL published the median values which were shared with IRP stakeholders and used to calculate life cycle greenhouse gas emissions for each portfolio.

emission factor. Emission factors for life cycle greenhouse gas emissions are presented in Figure 2.3.

Figure 2.3 – Life Cycle Greenhouse Gas Emission Factors (grams CO_2e/kWh)[13]

	Specific Technology	Market[14]
All Coal		1,002
Sub Critical	1,062	
Super Critical	863	
All Gas		474
Gas CT	599	
Gas CC[3]	481	
All Nuclear		16
Onshore Wind	12	12
All PV		54
Thin Film	35	
Crystalline	57	
All hydropower	7	7
Bio Power	43	43

To account for life cycle emissions from energy purchases imported from the market, Vectren used the MISO 2033 Futures energy utilization mix corresponding to the Accelerated Fleet Change mix from the 2019 MISO Transmission Expansion Planning Report (MTEP19)[15]. This estimation provides a figure of 347.4 grams of CO_2e/kWh as shown below in Figure 2.3a.

[13] Source: https://www.nrel.gov/analysis/life-cycle-assessment.html - Values derived from graphs included for each resource type. Note that battery storage was not estimated.
[14] Utilized when specific technology breakouts were not available within the MTEP study
[15] 2019 MISO Transmission Expansion Planning Report (MTEP19)
https://www.misoenergy.org/planning/planning/mtep-2019-/

Figure 2.4 – MTEP19 Accelerated Fleet Change Mix Used to Calculate CO_2e Emissions from Energy Imports

Resource	Given Percentage in MTEP19 Fig. 2.5-2	Normalized Percentage	Grams of CO2e per kWh (NREL)	Pro Rata Grams of CO2e per kWh
Coal	18%	15.7%	1,002	156.8
Nuclear	6%	5.2%	16	0.8
CC/ST Gas	23%	20.0%	481	96.2
CT	16%	13.9%	599	83.3
Wind	30%	26.1%	12	3.1
Utility Solar	10%	8.7%	54	4.7
DG Solar	5%	4.3%	54	2.3
DR	4%	3.5%	0	0.0
Other	3%	2.6%	0	0.0
Battery	0%	0.0%	0	0.0
Total	115%	100.0%		347.4

Outside of the scorecard, Vectren considered direct portfolio emissions reductions for each portfolio compared to a base year (2005) of power generation and resulting CO_2 emissions. The 2005 benchmark year saw 9,634,957 short tons of CO_2 emissions.

2.3.2.4 Market Overreliance Risk Minimization

For the Market Overreliance Risk Minimization objective, there were four metrics. There is the average annual energy sales and the average annual energy purchases, each divided by average annual generation and expressed as a percentage. There is also the average annual capacity sales and the average annual capacity purchases, divided by average total resources and expressed as a percentage.

Other Considerations

2.3.2.5 Uneconomic Asset Risk Mitigation

The recent generation order suggested that the consideration of future generation mix should include the risk that assets in the portfolio would become uneconomic due to technological advance. Vectren anticipated that the greatest risk would be imposed by capital intensive fossil plants as renewable assets became more economic with time.

To try to measure this risk, the probabilistic modeling provided an annual accounting of a plant's going-forward costs and revenues in each of the 200 iterations. In cases where the annual going-forward costs exceed the annual revenues for three consecutive years, the plant was deemed to be uneconomic[16] at that time. In the first year in which the plant was deemed uneconomic, the unamortized cost of the uneconomic asset and any additional losses in subsequent years was measured.

2.3.2.6 Resource Diversity Maximization

Vectren believes that resource diversity helps minimize risk to customers by providing a mix of resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed. Vectren's coal units have served its customers well over the years, but continued pressure on this resource from environmental regulations, increasing use of intermittent renewable resources and low gas prices have resulted in several units having a low dispatch rate. The concentration of coal in Vectren's generation mix has become costly to Vectren customers over time. Additionally, the Indiana Commission reinforced this consideration in a recent Order that Vectren should consider resource diversity and alternatives that provide off ramps that allow Vectren to react to changing circumstances.

While very important, it is hard to create a measure that adequately captures this value. Instead, Vectren sought to develop a number of portfolios that included a wide range of resource types and fuel sources. To ensure this objective has been met, Vectren built portfolios that ensure diverse mixes. One way in which this has been done is that Vectren did not consider a large 2x1 Combined Cycle Gas Turbine (CCGT) in the 2019/2020 IRP. While potentially an economic solution for customers, moving from mostly coal to mostly gas was considered a risk in the long term due to the lack of

[16] Definition of an uneconomic asset: When going forward costs of the asset, which include annual variable costs (fuel + variable operations & maintenance or VOM + emissions) plus annual fixed operations & maintenance or FOM costs, are collectively greater than the total annual revenues (including both energy revenues and capacity revenues) in three successive years

flexibility to adjust to future conditions. Additionally, Vectren included an All-Source RFP to fully consider renewable resources within all portfolios.

2.3.2.7 System Flexibility

System flexibility was an important consideration in the 2019/2020 IRP. As intermittent renewable resources continue to grow on the transmission and distribution system, it is important to back these resources up for reliability and resilience. As such, Vectren considered performance of resources with the ability to start and ramp quickly and be available for sustained periods in times when the sun is not shining and the wind is not blowing. Vectren also considers the transmission system and the ability to rely on the market as an important consideration in IRP planning. While Vectren has considerable import capabilities with the addition of the Duff Coleman Market Efficiency transmission Project (MEP) and the upcoming East/West line, this capability is not unlimited and requires needed upgrades to maintain reliability for portfolios that rely less on dispatchable energy resources.

2.4 REFERENCE CASE ASSUMPTIONS AND BOUNDARY SCENARIOS

After selecting the objectives and metrics, the next step in the process was to define the Scenarios for consideration in the selection of alternative portfolios. In this case Vectren selected a Reference Case and four alternative scenarios for two purposes. The first purpose was to select a least cost portfolio for each of the five scenarios and the second was to test final portfolios against each of the market scenarios to determine how well they perform. Below is a brief discussion of each. Greater detail is provided in Section 7 which identifies the key inputs for each scenario.

2.4.1 Reference Case

The Reference Case scenario represents the most likely future conditions. Vectren surveyed and incorporated a wide array of third-party sources to develop its Reference Case assumptions, several of which reflect a current consensus view of key drivers in

power and fuel markets. Reference Case assumptions include forecasts of the following key drivers:

- Vectren and MISO energy and demand (load)
- Henry Hub and delivered natural gas prices
- Illinois Basin mine and delivered coal prices
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial and industrial usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, electric vehicle adoption and several demographic and economic factors.

For natural gas, coal and capacity price, Vectren used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. This helps to ensure that multiple views are considered and allows Vectren to be transparent with modeling assumptions. For natural gas and coal, 2019 forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, and EVA were averaged. Based on a stakeholder request to include CO_2 in future years, Vectren decided to include a CO_2 price in the Reference case but not in the low regulatory case. The CO_2 forecast was developed by Pace Global. The capacity price forecast was based on MISO Zone 6 forecasts from Wood Mackenzie, Pace Global and ABB.

All-source RFP bids were utilized for resource cost information between 2022 and 2024, where possible. Long term cost curve information was developed utilizing a consensus approach, using Burns and McDonnell, NREL ATB and Pace Global. Burns & McDonnell

technology assessment helped fill in the gaps with operational data and for various traditional technologies like gas and coal resources.

Vectren worked with stakeholders and GDS to develop a Market Potential Study (MPS) for demand side resources. This study was used to create demand side inputs to be compared on a consistent and comparable basis with supply side resources.

Pace Global performed the production cost modeling used to create several key components of the IRP. Using the AURORAxmp power model, Pace Global developed an optimized, least-cost portfolio for the Reference Case, which was then run in chronological hourly dispatch mode. The deterministic dispatch run provided power price forecasts for MISO regions, as well as the least cost portfolios created utilizing the Reference Case. These key drivers constitute the Reference Case assumptions. More information on modeling inputs can be found in Section 7.2 Reference Case Scenario.

2.4.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just the Reference Case. Hence, Vectren, with the support of Pace Global, selected four alternative scenarios (a Low Regulatory, a High Regulatory, an 80% Carbon Reduction and a High Technology) to provide boundary conditions for testing the technologies and developing portfolios that could be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

Vectren worked with Pace Global and received input from Vectren stakeholders on key inputs such as load forecasts, gas and coal prices, carbon emission prices and technology capital costs. With input from stakeholders, Vectren and Pace Global determined whether gas prices, coal prices, load, technology capital costs, retirements/ builds, carbon emission prices and power prices would move up or down relative to the Reference Case under each of those scenarios. This process was followed to illustrate what might happen under each of these scenarios in a consistent manner with the risk

analysis. This wide range of scenarios is bounded on one end by a Low Regulatory future with no CO_2 price. Regulation of CO_2 and other regulations ratcheted up moving towards the outer boundary condition, the High Regulatory future. Below is an illustrative description of each scenario.

- Low Regulatory – The primary carbon regulation is assumed to be the ACE rule. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3). The limited regulation promotes a stronger economy, higher load and higher natural gas prices relative to the Reference Case. Other drivers still support declining coal demand over the planning horizon and as a result coal prices remain at levels similar to the Reference Case. Similarly, technology costs retain the same outlook as the Reference Case. This case is consistent with the theme that the Indiana Coal Council has consistently requested.

- High Technology – This scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to be more competitive without significant regulation. A low carbon tax is ultimately implemented. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the carbon tax. Increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the Reference Case. Less demand for coal results in lower coal prices. Utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy. As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes.

- 80% CO_2 Reduction by 2050 – This scenario assumes a carbon regulation mandating an ~80% reduction of CO_2 emissions from 2005 levels by 2050 is implemented. A gradually declining carbon cap drives carbon allowance costs up over time. Load decreases as the costs for energy and backup power increase and as the energy mix transitions. Natural gas prices remain at similar levels to the Reference Case as the impact of methane regulation is offset by lower demand and productivity increases that lower supply costs. Coal demand declines over time. Renewables and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns.

- High Regulatory – The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee set at the social cost of carbon is implemented early in the planning horizon (2022). Monthly rebate checks (dividend) redistribute revenues from the tax to American households based on number of people in the household. A fracking ban is imposed, driving up the cost of natural gas notably in the long-term as supply dramatically shrinks. Declining demand for coal results in coal prices lower relative to the Reference Case. With the higher costs, innovation occurs as renewables and battery storage are widely implemented to avoid paying high carbon prices, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

A summary of the relative outlooks for key market drivers across the scenarios considered is presented in Figure 2.5.

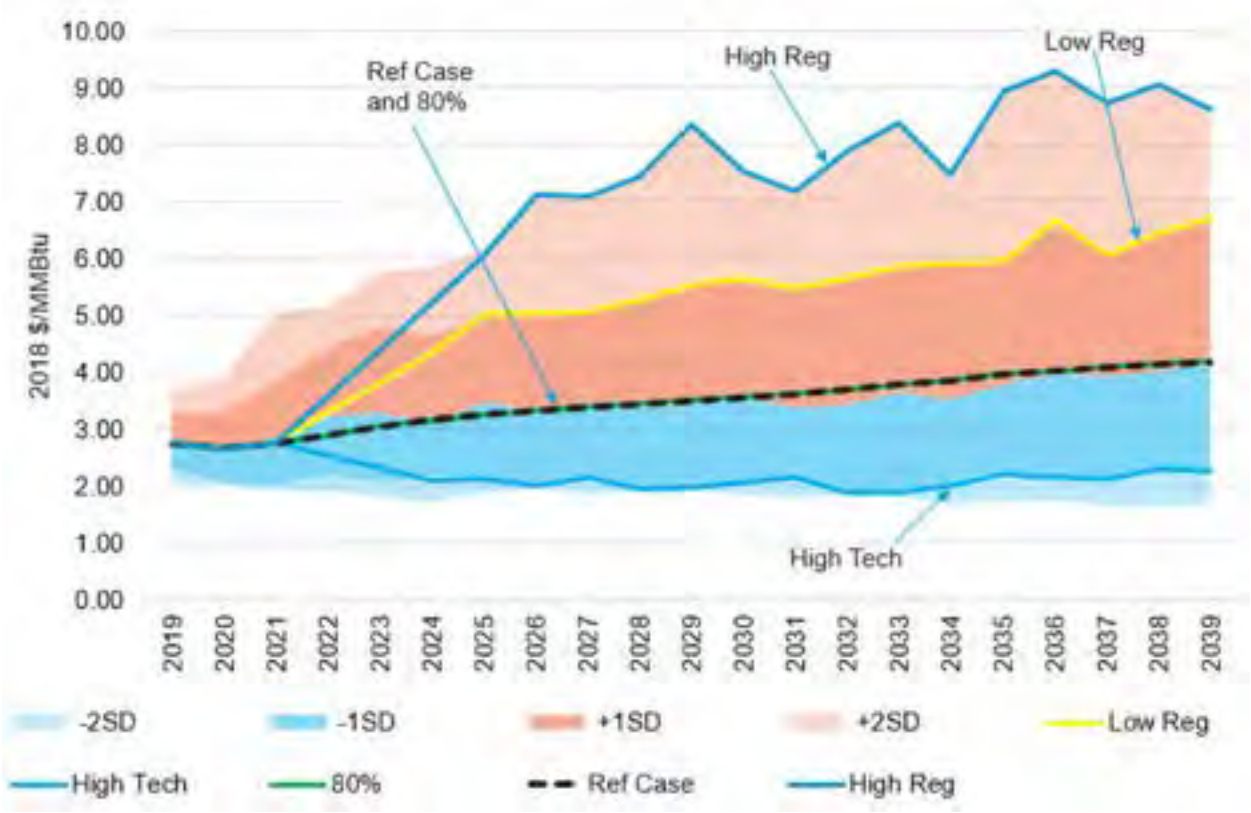
Figure 2.5 – Summary of Directional Relationships of Key Inputs Across Scenarios

	CO_2	Gas Reg.	Water Reg.	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	EE Cost
Reference Case	ACE Replaced with CO_2 Tax	none	ELG	Base	Base	Base	Base	Base	Base
Low Regulatory	ACE	none	ELG Light*	Higher	Higher	Higher	Base	Base	Base
High Technology	Low CO_2 Tax	none	ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	CO_2 Cap	Methane	ELG	Lower	Lower	Base	Lower	Lower	Higher
High Regulatory	High CO_2 Tax w/ Dividend	Fracking Ban	ELG	Base	Base	Highest (+2 SD)	Lower	Lower	Higher

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years. Does not apply to Culley 3

Using the Reference Case as a consistent starting point, the boundary scenarios were developed. Key variables are assumed to remain the same as the Reference Case in the short-term (2019-2021). In the medium-term (2022-2028), key variables grow or decline to +/-1SD or (+/-2SD) by 2025 (midpoint of medium-term) as shown in the table above. After 2025, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2039. Because this price path remains at the one (or two) standard deviation(s) path for the entire planning horizon, these levels have a low probability and are viewed as very wide. The five scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (five scenarios). An illustration of this methodology for natural gas prices is presented in Figure 2.6

Figure 2.6 – Henry Hub Natural Gas Price Scenarios (2018$/MMBtu)



All gas prices begin at $2.77/MMBtu in 2019, dip slightly in 2020 and rise back to $2.76/MMBtu in 2021. After this time, the Reference Case gas prices gradually trend upward to $4.17/MMBtu in 2039. Gas prices in the other scenarios either follow the Reference Case or trend higher or lower, depending on the scenario's coordinated input direction. Gas prices in the High Regulatory scenario are designed to reach the +2 standard deviation level to replicate the price impact of a hydraulic fracturing ban, which would greatly limit domestic production, increase costs and put upward pressure on prices last seen prior to 2008 before the shale boom era began. The High-Tech scenario sees natural gas prices moving downward to -1 standard deviation below the Reference Case.

The convention of +/-1 standard deviation is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should

be noted that the historical price distributions differ among the various market drivers are not necessarily symmetrical (i.e., normally distributed). For example, gas prices are positively skewed because they have no upper boundary and can reach many standard deviations above the historical average, whereas they typically cannot fall below zero (or approximately two standard deviations below the historical average).

Note that the selection of one standard deviation up in every year of the study means that the actual price in any one year may exceed that value 15.8% of the time, but over the entire 20 year planning horizon only about 5-7% of the time the price will exceed the price on the curve. Selecting a 2 standard deviation change, as was done for gas prices, means that only 2.2% of the time the price in any one year will exceed the value selected and over the 20-year planning horizon; the chances of a higher average price is less than 1 percent.

The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices and power prices) are shown in Section 7.3.2.2.

2.5 PORTFOLIO DEVELOPMENT

The portfolio development process was designed to test a wide range of technology options. An exhaustive list of technology options was developed and then refined. The viability of existing resources was considered as well as new resources including demand side measures of varying sizes and timeframes. The wide range of portfolio strategies was informed by stakeholder feedback as well as the All-Source RFP.

A Burns & McDonnell technology assessment defined the list of technologies and provided cost and performance information for resources. Where possible, technology costs from the All-Source RFP bids were utilized. Long-term cost projections were based on consensus estimates from three sources. These long-term cost estimates were averaged with outlooks from Pace Global and NREL to form the consensus technology

cost projections over the planning horizon. A total of 30 resource options for power supply were included in the analysis. These included wind with and without storage, solar with and without storage, hydroelectric, landfill gas, several battery storage options, simple cycle and combined cycle natural gas and natural gas fired combined heat and power technologies. Note that Aeroderivative turbines and gas reciprocal engines were excluded based on the cost per KW and high gas pressure needed to run them. Two new coal-fired technologies were included, both of which were assumed to be equipped with carbon capture and storage.

An All-Source RFP was issued at the onset of the IRP process to obtain actual market information for near term indicative pricing for a wide range of technologies. The average delivered cost by resource informed the modeling and portfolio options. This included new builds, power purchase agreements, demand response and other supply options. The results of the All-Source RFP were vetted by Burns & McDonnell and ultimately converted into model inputs.

Long Term Capacity Expansion (LTCE) Assessments

The AURORAxmp power model (Aurora) was used as the central tool in the IRP to develop the 14 candidate portfolios in addition to the Reference Case portfolio. The long-term capacity expansion functionality within Aurora was used to develop least cost optimized portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants.

Market transactions offer supply flexibility but also exposure to potential market risk to Vectren customers. In addition to the supply and demand side resource alternatives, portfolios were able to select market supply options as well. To reduce the risk that comes from exposure to the market, a limit of approximately ~15% of capacity needs, or 180 MW, was defined for annual capacity market purchases (except in a transitional year). This is much more than the 2016 IRP where a 10 MW cap was utilized and is responsive

to the Commission Order 45052, which said Vectren did not fully consider energy or capacity purchases.

Portfolios were selected in a few different ways.

- Least cost portfolios were developed for the Reference Case and the other market and regulatory scenarios (5 Portfolios)
- Least cost portfolios with some modifications to existing units
- Stakeholder driven least cost portfolios

Portfolios were developed utilizing AURORA's LTCE modeling for the Reference Case and the four alternate scenarios. The model uses hourly chronological dispatch over a 20-year period, which means that outcomes are based on all 8,760 hours each year over a 20-year span. This helped to better evaluate intermittent renewable and storage resources.

In addition, alternative portfolios were developed by Vectren and based on stakeholder input to specifically test alternate resource strategies. These include the following additional 10 resource portfolios:

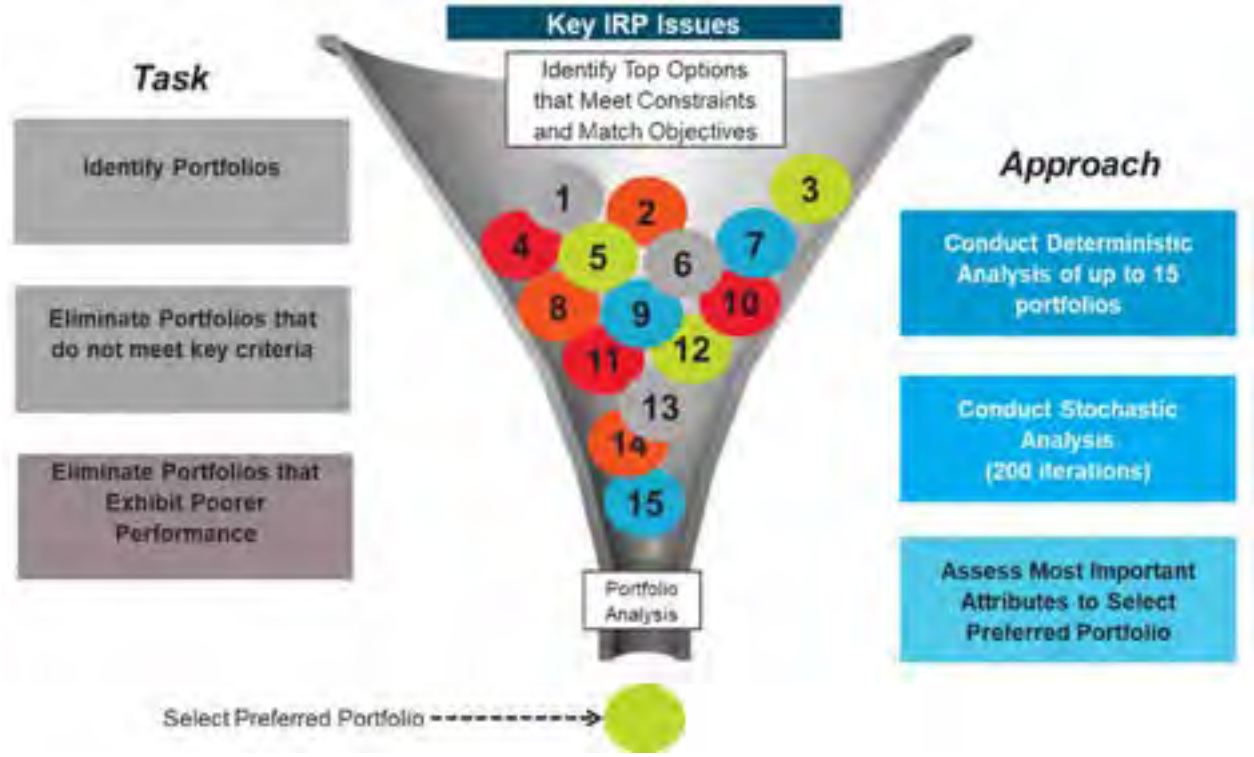
1. Business as usual to 2039 including the continued operation of all existing units (joint operations of Warrick 4 ends by 2024);
2. Bridge with business as usual to 2029, including the continued operation of A.B. Brown units 1 & 2 through 2029;
3. Bridge in which A.B. Brown 1 is converted to natural gas;
4. Bridge in which both A.B. Brown 1 and 2 are converted to natural gas;
5. Bridge in which A.B. Brown 1 is converted to natural gas and a CCGT is added;
6. Diverse energy portfolio including a new small (443 MW) natural gas CCGT;
7. Diverse energy portfolio including a new medium (511 MW) natural gas CCGT;
8. Renewables portfolio utilizing a combination of renewables, storage and peaking natural gas;

9. Renewables portfolio with no fossil technology options allowed in the portfolio by 2030; and
10. Portfolio based on HB 763 CO_2 price, which reaches $200/ton by the end of the study period.

In each of these LTCE assessments, the refinement for each portfolio, whether it be a modification to an existing unit or requiring the addition of a CCGT as a minimum requirement was required as part of a portfolio and then the model selected the remainder of the portfolio on a least cost basis.
Figure 2.7 – Structured Portfolio Selection Process illustrates the portfolio screening process applied in the analysis to select the preferred portfolio.

As described in Section 8, Vectren selected 10 of the 15 least cost portfolios for evaluation in the risk analysis. The selection criteria for eliminating the five portfolios are provided in that section.

Figure 2.7 – Structured Portfolio Selection Process



2.6 PORTFOLIO PERFORMANCE (SCENARIO BASED RISK ASSESSMENT)

The framework of the Indiana law mandating a triennial IRP[17] also requires the creation of alternative future scenarios with unique sets of inputs. Each candidate portfolio must be modeled in a dispatch run using these scenario-based inputs, which can provide a complementary view of portfolio strengths and weaknesses, separate from the probabilistic analysis that serves as the basis for scorecard measures. Four alternative scenarios were created (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory), each with a unique set of inputs. All 10 candidate portfolios were modeled in a separate dispatch run for each of the four alternative scenarios.

AURORA is run in a market simulation mode holding each of the Vectren portfolios constant but allowing other MISO members to modify its decisions on the basis of the Scenario selected. The results of the scenario-based risk analysis are summarized in Section 8.2.1.

2.7 PORTFOLIO PERFORMANCE (PROBABILISTIC OR STOCHASTIC MODELING RISK ASSESSMENT)

Probabilistic modeling incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for the balanced scorecard and key drivers portion of the risk analysis. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (at the Vectren, MISO Local Resource Zone 6 (LRZ6) and MISO levels) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. These 200 iterations of each stochastic variable are

[17] Indiana Code § 8-1-8.5

then loaded as inputs into the dispatch model. These inputs thus allow for the testing of each portfolio's performance across a wide range of market conditions.

Once again, all 10 portfolios were subjected to each of the 200 iterations (scenarios) using AURORA in dispatch mode where the Vectren portfolio is fixed but other MISO members can make decisions under each market scenario.

2.8 SENSITIVITY ANALYSIS

Vectren conducted several sensitivities in order to put brackets around resulting portfolios when one or more variables were adjusted. Sensitivities were also conducted to ensure seasonal Planning Reserve Margin (PRM) targets are met and that the candidate portfolio buildouts are calibrated to the greatest annual constraint, which occurs in the summer peak period.

- Vectren ran sensitivities to compare portfolio buildouts with winter solar/wind peak capacity credit on winter peak demand versus portfolio buildouts with summer solar/wind peak capacity credit on summer peak demand. Portfolios that are overly reliant on solar generation may risk not meeting MISO Planning Reserve Margin Requirements in the winter, as rules continue to evolve.
- Vectren performed sensitivities using a seasonal PRM target and seasonal peak capacity accreditation (solving to monthly peak hour). This sensitivity resulted in a solar peak capacity credit that approached zero as the Vectren system approached 2,000+ MW solar.
- Vectren performed a sensitivity in which the cost of a solar PPA resources increases 30%, based on more recent market information. The sensitivity demonstrated that even with increased costs, the solar PPA costs remain below the market clearing on-peak price of $42-45/MWh and continue to be selected as economic portfolio additions.
- Vectren conducted sensitivities to right-size several portfolios that had more capacity than needed in the early years of the transition from the point of view of the PRM target, but the model selects several early resources to capture the

benefits of the wind Production Tax Credit and solar Investment Tax Credit. Early solar and wind resources help to lower total cost of each portfolio.

- Sensitivities were run on the Reference Case and High Technology portfolios, swapping combustion turbine capacity for storage capacity. Portfolio costs rose as a result, but costs can vary widely depending on whether augmentation (replace dead battery cells) and other costs are fully incorporated into the bid price.
- A sensitivity was run on the Reference Case to assess 1.25% energy efficiency (EE) in the near-term as compared to the selected 0.75% EE in the near-term, which raised portfolio costs by 0.15%. As such, 1.25% was included in all portfolios for the first 3 years.

2.9 BALANCED SCORECARD

The Risk Analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the AURORAxmp dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term and long-term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the AURORAxmp production cost model. AURORAxmp dispatches the candidate portfolio for each sampled hour over the

planning horizon. For this risk analysis procedure, AURORAxmp assumes that each Vectren candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.

- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the balanced scorecard.

The results of risk analysis can be found in Section 8 Portfolio Development and Evaluation

2.10 SELECTION OF THE PREFERRED PORTFOLIO

The risk analysis includes scenario modeling, probabilistic modeling, sensitivity and other analyses to inform judgment in the selection of the preferred portfolio. In addition, a key part of selecting the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, under 200 iterations representing different, but internally consistent and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each candidate portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations, while also maintaining reliability and providing resource diversity/system flexibility. To help illustrate tradeoffs, Vectren used a Balanced Scorecard, as shown below in Figure 2.8 and further discussed in Section 8.

Figure 2.8 – Balanced Scorecard Illustration

Balanced Scorecard		Objective	Affordability	Price Risk Minimization	Environmental Risk Minimization	Market Risk Minimization		Market Risk Minimization	
		Metric	20-Year NPVRR ($million)	95th percentile NPVRR ($million)	Life Cycle GHG Emissions (million tons CO2e reduction 2019-2039)	Energy Market Purchases & Sales (% of generation)		Capacity Market Purchases & Sales (% of peak demand)	
No	Group	Candidate Portfolio				Purch	Sale	Purch	Sale
1	Reference	Reference Case							
2	BAU	BAU to 2039							
3		BAU to 2029							
4	Bridge	ABB1 gas conversion							
5		ABB1+ABB2 gas conversions							
6		ABB1 gas conversion + CCGT							
7	Diverse	Diverse Small CCGT							
8	Renewables	Renewables+ Flexible Gas							
9		Renewables 2030							
10	Scenario	High Technology							

The preferred portfolio represents Vectren's assessment, based on the analysis, of an appropriate balance between all identified objectives (See Figure 2.2) under a wide range of future conditions.

SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION PROCESS

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was given to improve the process. As a result, significant stakeholder input was directly included in key areas of the IRP, including but not limited to portfolio development, scenario development; scorecard development (metrics and measures), and modeling inputs such as energy efficiency inputs. While improvements have been made, Vectren's objectives for stakeholder engagement remain the same:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions and the challenges facing Vectren and the electric utility industry
- **Consider**: Provide a forum for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform Vectren's decision making

IRP stakeholders include, but are not limited to, Vectren residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders and elected officials.

In the first public stakeholder meeting, Vectren publicly made 12 commitments and followed through with all throughout the process:

1. To strive to make every encounter meaningful for stakeholders and for us
2. To provide a data release schedule and provide modeling data ahead of filing for evaluation
3. That the IRP process informs the selection of the preferred portfolio
4. To utilize an All-Source RFP to gather market pricing & availability data
5. To use one model for consistency in optimization, simulated dispatch and probabilistic functions
6. To attempt to model more resources simultaneously

7. To include a balanced, less qualitative risk score card
8. To work with stakeholders on portfolio development
9. To test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
10. To conduct a sensitivity analysis
11. To take an exhaustive look at existing resource options
12. That the IRP will include information presented for multiple audiences (technical and non-technical)

The first three stakeholder meetings began with stakeholder feedback. Vectren would review all requests since the last stakeholder meeting and provide feedback. Often suggestions were incorporated, but in instances where suggestions were not. Vectren made a point to discuss further and explain why not. Per stakeholder feedback, 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 session per request. The final meeting was a preview of the preferred portfolio and a discussion of analysis. Due to COVID, this meeting was held via webinar.

The first three public stakeholder meetings were held at Vectren headquarters in Evansville, IN. Dates and topics covered are listed below:

Figure 3.1 – 2019/2020 Stakeholder Meetings

August 15, 2019	October 10, 2019	December 13, 2019	June 15, 2020
• 2019/2020 IRP Process • Objectives and Measures • All-Source RFP • Environmental Update • Draft Reference Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Reference Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Scenario Testing and Probabilistic Modeling Approach and Assumptions	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

Meeting materials of each meeting can be found on www.vectren.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

3.2 KEY ISSUES DISCUSSED

Throughout the process Vectren engaged stakeholders on all key inputs into the IRP, which helped shape the outcome of the analysis. In the first stakeholder meeting, Vectren presented a draft balanced scorecard which was used to evaluate key tradeoffs among portfolios. Adjustments were made and presented to stakeholders before modeling commenced. Vectren worked closely with stakeholders to develop scenario concepts and helped to refine various scenario inputs. Additionally, stakeholders provided input into portfolio development, which helped to provide a wide range of portfolios, included continuation of the Brown coal units through 2029 or 2039 and an all renewables portfolio by 2030.

3.3 STAKEHOLDER INPUT

During the 2019/2020 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; 3) via written feedback/requests; 4) telephone conversations; and 5) meetings between stakeholder sessions.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Lynnae Wilson, Chief Business Officer for Indiana Electric. She and other senior management, Vectren subject matter experts and expert consultants actively participated in each meeting to help address stakeholder questions/concerns.

Below is a summary of key feedback during the 2019/2020 IRP that heavily influenced the analysis. For a full list, see the technical appendix Technical Appendix Attachment 3.1 Stakeholder Materials.

Figure 3.2 – Summary of Key Stakeholder Input

Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed less impact on the economy/load
Lower renewables costs in the High Regulatory and 80% CO_2 Reduction scenarios	Updated scenario to include lower costs for renewables and storage than the Reference scenario
Consider life cycle emissions using CO_2 equivalent	Included a quantitative measure on the risk scorecard based on National Renewables Energy Laboratory (NREL) Life Cycle

Request	Response
	Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers sunk costs	Vectren worked with Pace Global to create an uneconomic asset risk measure. Ultimately, this measure was considered but not included within the scorecard, it did not fulfil the initial intention, to evaluate risk of resources with large initial capital investments
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price curve that was approximately $200 by the end of the forecast	Ran a sensitivity to create a portfolio. Ultimately, this was not selected for the risk analysis, as the amount of generation built within modeling vastly exceeded Vectren's need
Reconsider the use of a seasonal construct for MISO resource accreditation	Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter
Include a CO_2 price in the reference case	Included a mid-range CO_2 price curve 8 years into the forecast. The low regulatory scenario did not include a CO_2 price, and remains a boundary condition

3.4 DATA REQUESTS SUMMARY

One of the key data requests made was to provide access to all-source RFP bids. While protecting confidentiality commitments to bidders' competitively sensitive information, Vectren provided two consumer groups (OUCC and CAC) who signed a NDA with electronic read-only access via a locked down SharePoint site. A data key was provided

for convenience to show the difference between tier one and tier two bids and many attributes of each bid. Additionally, Vectren received a data request from the CAC on December 9, 2019. Per their request, Vectren provided wind and solar resource shape files, input files utilized in the load forecast for regression modeling along with documentation, probabilistic modeling distributions for natural gas, capital cost, carbon price and peak load and costs associated with the retirement of existing thermal units.

CAC also requested modeling files as a part of their review process, prior to filing the IRP. In order to accommodate this request, Vectren worked with them to provide files to the OUCC and CAC on May 15, 2020 in preparation for the final stakeholder meeting on June 15th. Vectren held a discussion with these stakeholders on May 26th to answer questions and walk them through the file formats. Vectren worked to answer questions leading into and after the final IRP stakeholder meeting.

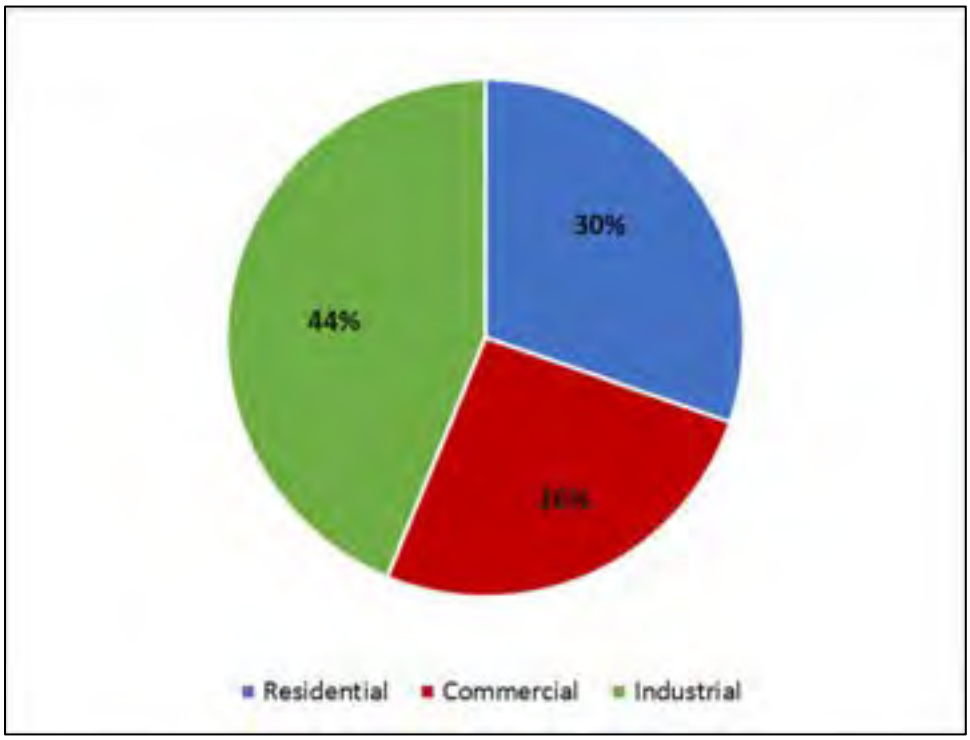
CAC also issued Data Request 2 on 6-5-20, Data Request 3 on 6-10-20 and Data Request 4 on 6-11-20. Vectren provided responses ahead of the required timeframe and before the filing of the IRP.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren serves more than 146,000 electric customers in Southwest 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 2018. The residential class accounts for 30% of sales with approximately 128,000 customers and the commercial class 26% of sales; there are approximately 18,000 nonresidential customers. System 2018 energy requirements were 5,308 GWh with non-weather normalized system peak reaching 1,039.2 MW. Figure 4.1 shows 2018 class-level sales distribution.

Figure 4.1 – 2018 Vectren Sales Breakdown



4.2 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 over ten years of historical energy and demand data within the energy and demand forecasts. This data is maintained by Vectren 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. Similarly, small 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 Moody's Economy.com, 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. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 20-year period for the sales forecast and a 20-year period for the demand forecast in order to capture recent weather activity.

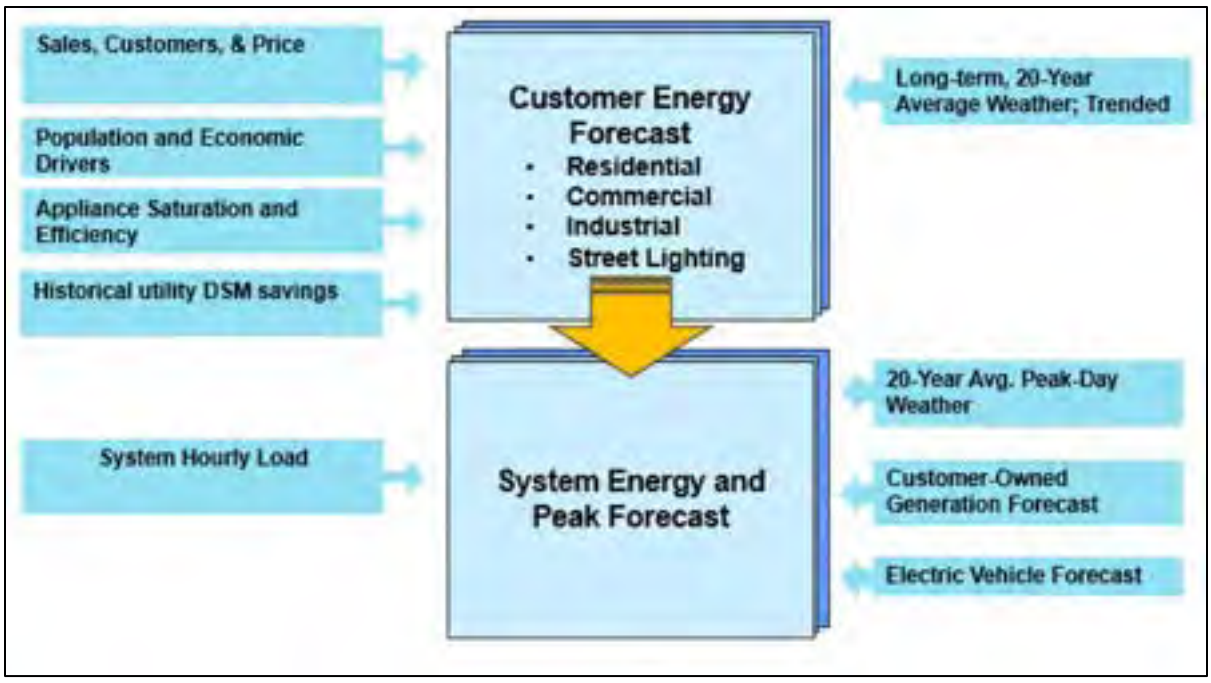
Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including 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 Vectren's service territory based on the latest appliance saturation survey data.

4.3 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 4.2 shows the general framework and model inputs.

Figure 4.2 – 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.

4.4 CUSTOMER OWNED DISTRIBUTED ENERGY RESOURCES

Distributed generation (DG) is an electrical source interconnected to Vectren's transmission or distribution system at the customer's site. The power capacity is typically small when compared to the energy companies' centralized power plants. DG systems allow customers to produce some or all of the electricity they need. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load. With respect to Vectren's electric service territory, DG will likely take these forms:

Small – 10 kW and under – roof-top photovoltaic (PV) systems, small wind turbine, etc. interconnected at distribution secondary voltage (120/240 V, etc.)

Medium – 10 kW to 10 MW – large scale PV systems, wind turbine(s), micro-turbine(s), etc. interconnected at distribution primary voltage (4 kV or 12 kV)

Large – 10 MW and over – heat recovery steam generator, combustion turbine, etc. interconnected at transmission voltage (69 kV and over)

Most renewable DG systems only produce power when their energy source, such as wind or sunlight, is available. Due to the intermittency of the power supply from DG systems, there will be times when the customer needs to receive electricity from Vectren. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to Vectren's electric system through a program called net metering. The customer is charged the retail rate for the net power that they consume.

4.4.1 Current DG

As of December 2019, Vectren had approximately 486 residential solar customers and 71 commercial solar customers, with an approximate installed capacity of 10.7 MW. Based on recent solar installation data, the residential average size is 10.5 KW, while the commercial average system size is 78.7 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren monitors Combined Heat and Power (CHP) developments in its service area and adjusts the load forecast for any known, future customer owned CHP installations. A large CHP system went into service on Vectren's system in 2017.

4.4.2 Solar DG Forecast

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline.

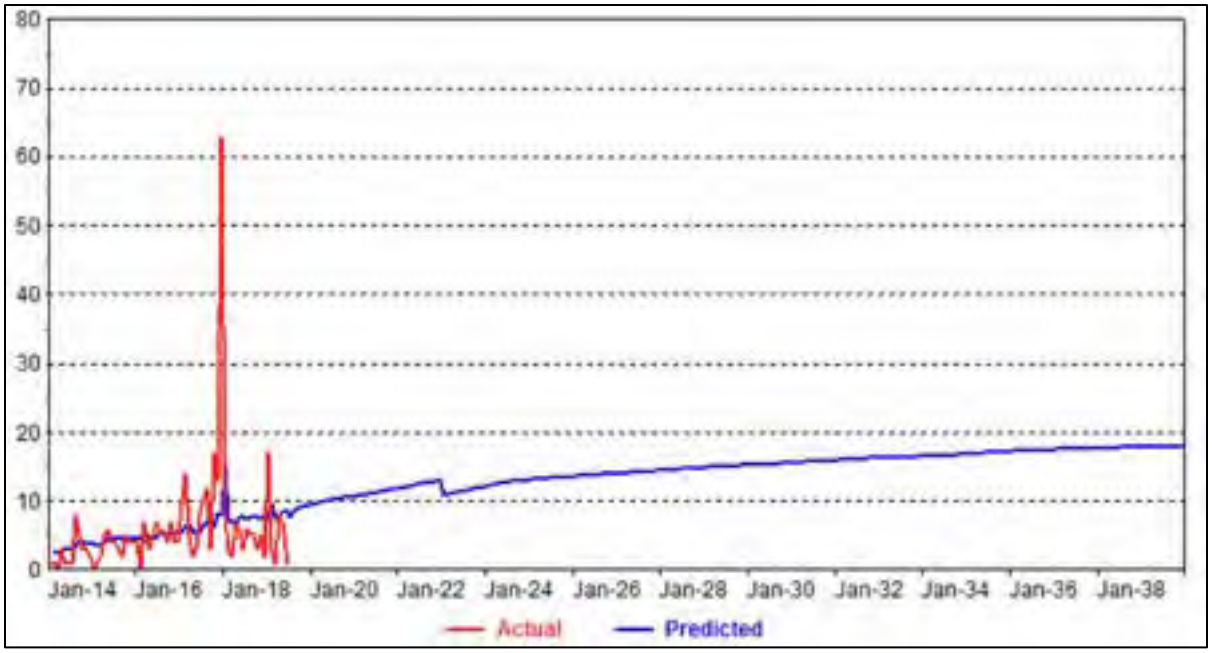
The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity generated from the system is considered "free." Solar

investment payback is calculated as a function of system costs, tax credits, and incentive payments, retail electric rates and treatment of excess generation (solar generation returned to the grid). Currently, excess generation is credited at the customer's retail rate. While current net metering customers will be credited the retail rate, DG installed beyond 2021 will be credited at the wholesale cost plus 25%.

One of the most significant factors driving adoption is declining system costs, which have been declining rapidly over the last several years. In 2010, residential solar system cost was approximately $7.00 per watt. By 2017 costs had dropped to $3.70 per watt. For the forecast period, Itron assumed system costs will continue to decline 10% annually through 2024 and an additional 3% annually after 2024. Customer owned solar cost projections are consistent with the U.S. Dept. of Energy's Sun Shot Solar goals and national trends.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 4.3 shows the resulting residential solar adoption forecast.

Figure 4.3 – Residential Solar Share Forecast



In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Some challenges to commercial adoption are higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill) and physical constraints as to the placement of the system. For this forecast, Itron assumed there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates.

As shown in Figure 4.4, installed capacity of solar is expected to increase at a compound annual growth rate of 10.9% with 84.3 MWs by 2039.

Figure 4.4 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity (Aug) MW	Demand Impact MW
2019	20,144	9.3	2.7
2020	23,260	11.8	3.5
2021	26,856	14.6	4.3
2022	30,834	17.6	5.2
2023	34,842	20.7	6.1
2024	38,999	23.8	7.0
2025	43,290	27.1	8.0
2026	47,880	30.6	9.0
2027	52,577	34.2	10.1
2028	57,535	37.9	11.2
2029	62,462	41.7	12.3
2030	67,499	45.6	13.4
2031	72,742	49.6	14.6
2032	78,272	53.6	15.8
2033	83,492	57.7	17.0
2034	89,074	62.0	18.3
2035	94,787	66.3	19.5
2036	100,707	70.6	20.8
2037	106,394	75.1	22.1
2038	112,446	79.7	23.5
2039	118,499	84.3	24.8
CAGR 2020-2039	8.9%	10.9%	10.9%

4.4.3 Potential Effects of Distributed Generation on Transmission and Distribution

Distributed Generation customers currently affect a small amount of load on each respective distribution circuit, which has not caused significant operational issues for Vectren. At higher levels of DG penetration, Vectren would encounter more operational issues and would need to allocate more resources to mitigate these issues. Some examples of potential issues would include:

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output.

- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer. Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company.
- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc.
- **Short term load forecast uncertainty** – At higher levels of DG penetration, short term load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. A load forecasting technique would need to be implemented that is more granular and more responsive to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and maintain acceptable voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, capacitor bank placement will need to be reevaluated.
- **Electric Rates** – Vectren's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed monthly charge does not reflect the full amount of fixed costs that Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying towards the recovery of the fixed costs of the grid that are recovered through the energy charge, which leads to Vectren's under recovery of the cost of providing service. Over time, as base rates are updated periodically,

recovery of these costs shifts to non-net metering customers, resulting in a subsidy to net metering customers.

- **Transmission Power Flows –** High DG penetration impact power flow on transmission lines. Depending on the concentration and location of these resources, the transmission system may need to be reconfigured, with consideration given to the dependency of the resources on the weather (wind, solar, etc.). High DG penetration may also impact flows on transmission system tie lines to other entities and require additional mitigations, such as installation of reactors or phase shifters to control flows.
- **Generation Reserves** – With the output of DG being weather dependent, the remaining fleet of generators and the electric system must be capable of quickly reacting to the fast and potentially large generation changes on the system, as well as providing generation support during times when DG will not be available (such as nighttime for solar DG). The adoption of Electric Vehicles could also lead to increased load demand in the nighttime hours as they are charging. These issues will need to be evaluated and potentially require mitigations such as storage facilities, quick start generators, etc.
- **Additional Operational Challenges** – High DG penetration causes additional challenges to operate the electric system in a safe and reliable manner due to loss of inertia on the power system by replacing traditional rotating machine generators (high inertia) with inverter-based generators (no/low inertia). These challenges include maintaining spinning and quick start reserves, power system frequency fluctuations and increased system operations (tripping), among others. Each of these issues would need to be evaluated and potentially mitigated to maintain reliable and safe power system operation.

4.5 ELECTRIC VEHICLES

4.5.1 Current EVs

In 2019, Vectren estimated 238 registered electric vehicles were in the counties that Vectren serves: this included full electric (i.e., Battery Electric Vehicles - BEV) as well as plug-in hybrid electric (PHEV) vehicles. The 238 vehicles were comprised of 105 BEVs and 133 PHEVs, with a total of 23 different make/model vehicles represented. This estimate was based on Indiana BMV registration data for the counties that Vectren serves. Vectren purchases quarterly from the BMV a list of vehicle registrations for the counties that Vectren serves.

4.5.2 EV Forecast

As electric vehicles are gaining more traction in the vehicle market, Vectren decided to include an electric vehicle forecast in the 2019/2020 IRP. As described in the 2019 Long-Term Electric Energy and Demand Forecast Report in the Technical Appendix of this IRP, Itron created an electric vehicle forecast utilizing the Energy Information Administration (EIA) Annual Energy Outlook (AEO) transportation forecast to estimate the number of cars per household over time. This number is multiplied by the forecast of residential customers to create a projected number of vehicles per Vectren household. Itron then applied the EIA AEO projected saturation of battery electric vehicles and plug in hybrid electric vehicles.

Electric vehicles' impact on Vectren's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. BEVs consume more electricity than PHEVs and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual kWh for the current mix of EVs registered in Vectren's service territory is 3,752kWh for BEV and 2,180 kWh for PHEV based on annual mileage of 12,000 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since Vectren does not have incentivized BEV/PHEV off-peak charging rates, it is assumed that most of the charging will occur at home in the evening hours. Table 4.5 shows the electric vehicle forecast.

Figure 4.5 – Electric Vehicle Load Forecast

Year	BEV MWh	PHEV MWh	Total EV MWh	Demand Impact MW (Aug)	Demand Impact MW (Jan)
2019	432	305	737	0.1	0.1
2020	1,063	580	1,643	0.2	0.1
2021	2,667	1,110	3,777	0.4	0.3
2022	6,691	2,124	8,815	1.0	0.6
2023	14,769	3,732	18,501	2.1	1.4
2024	19,178	4,503	23,681	2.5	2.2
2025	22,770	5,106	27,876	2.9	2.7
2026	26,320	5,697	32,017	3.3	3.1
2027	29,838	6,275	36,113	3.8	3.5
2028	33,334	6,837	40,171	4.2	3.9
2029	36,869	7,392	44,261	4.6	4.3
2030	40,467	7,933	48,400	5.0	4.8
2031	44,164	8,455	52,619	5.5	5.2
2032	47,920	8,959	56,878	5.9	5.6
2033	51,735	9,438	61,173	6.3	6.1
2034	55,591	9,895	65,486	6.8	6.5
2035	59,461	10,327	69,788	7.2	7.0
2036	63,315	10,741	74,056	7.7	7.4
2037	67,111	11,137	78,248	8.1	7.8
2038	70,863	11,510	82,373	8.5	8.3
2039	74,607	11,872	86,479	8.9	8.7
CAGR 2020-2039	25.1%	17.2%	23.2%	22.7%	25.7%

4.5.3 Potential Effects on Generation, Transmission and Distribution

Electric Vehicles and their associated charging stations currently have a minimal impact on the Vectren electric system and therefore have not caused significant operational issues. As the level of EV charging stations increases, Vectren may encounter multiple operational issues that will need to be evaluated and potentially mitigated. Some examples of potential issues include:

- **Shifting Peak Load** – Increased use of EV will have an impact on the magnitude of daily load demand, as well as the timing of peak loading. If a large concentration of EV charging occurs in the late afternoon and early evening, the daily system peak could be shifted to later in the afternoon or a second (and most likely lesser) peak could occur in the evening.
- **Generation Reserves** – If EV charging largely occurs in the evening or overnight, the electric system would see higher than typical load demand values at times when DG and other solar generation installations would not be available. This would lead to a need for generation support during these hours, such as energy storage facilities, quick start generators, etc.
- **Peak Charging** – If a large portion of EV charging were to occur during peak loading times, the impact of the increased demand could lead to overloaded electrical infrastructure, unless some form of delayed or managed charging is available. These overloaded facilities would need to be upgraded or other system level upgrades would be needed to mitigate the overload conditions.
- **Transmission Planning Concerns** – MISO performs economic studies annually using a range of potential futures. The futures that they are currently evaluating include potential increases in electrification (including EV) at various growth levels. Due to the uncertainty around EV adoption and the differing values being analyzed, uncertainties as to when to complete transmission system upgrades to support a higher level of system peak load due to EV adoption may be introduced. A need for additional planning models and sensitivity analysis would be required to evaluate these uncertainties and determine the appropriate time to perform the needed transmission system upgrades.

- **Dynamic Behavior** – The dynamic behavior of these loads while in a charging state during fault conditions and during re-energization post fault condition is an additional issue that will need to be evaluated. Research is still needed to properly reflect how these types of loads respond from a dynamic behavior perspective and may require additional dynamic modeling for planning studies.

If there is a substantial increase in EV adoption within the next 10 years, it is anticipated that there would be a significant change in the system load profile. As an example, the system peak load hour could shift to later in the day. The load profile and generation expansion implications of the changing load shape suggest that EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

4.6 ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP filing, 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, total energy requirements and peak demand are expected to average 0.6% annual growth over the next 20 years. The table below shows Vectren'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 Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.6 – Energy and Demand Forecast[18]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2019	5,147,837		1,115		826	
2020	5,374,079	4.4%	1,100	-1.4%	831	0.6%
2021	5,380,877	0.1%	1,102	0.2%	828	-0.3%
2022	5,505,660	2.3%	1,126	2.2%	847	2.3%
2023	5,742,090	4.3%	1,168	3.7%	886	4.6%
2024	5,774,656	0.6%	1,173	0.5%	891	0.5%
2025	5,789,928	0.3%	1,176	0.3%	891	0.1%
2026	5,807,569	0.3%	1,179	0.3%	892	0.1%
2027	5,828,395	0.4%	1,183	0.3%	894	0.2%
2028	5,858,975	0.5%	1,189	0.5%	898	0.4%
2029	5,874,831	0.3%	1,192	0.3%	898	0.1%
2030	5,891,575	0.3%	1,196	0.3%	899	0.1%
2031	5,909,760	0.3%	1,200	0.3%	900	0.1%
2032	5,934,963	0.4%	1,205	0.4%	902	0.3%
2033	5,949,314	0.2%	1,209	0.3%	902	0.0%
2034	5,970,284	0.4%	1,214	0.4%	903	0.1%
2035	5,992,643	0.4%	1,219	0.4%	905	0.2%
2036	6,019,773	0.5%	1,225	0.5%	907	0.3%
2037	6,034,306	0.2%	1,229	0.4%	907	0.0%
2038	6,053,929	0.3%	1,234	0.4%	908	0.1%
2039	6,072,712	0.3%	1,239	0.4%	909	0.1%
CAGR 2020-2039		0.6%		0.6%		0.5%

4.7 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD and PEAK LOAD

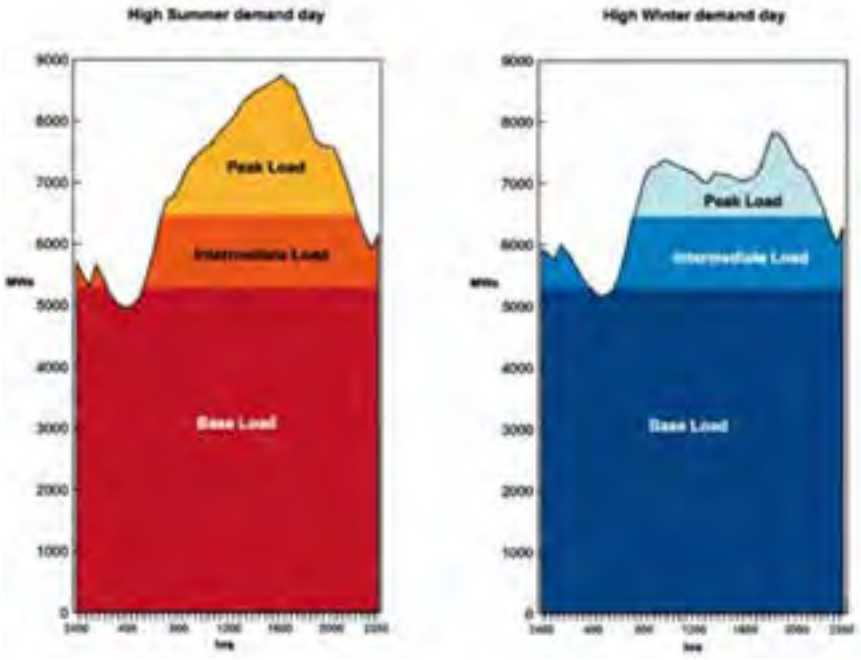
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level of demand. Plants can operate between extremes and generally have output increased in the morning and decreased in the evening. Peak load is the highest level of demand within a 24-hour period. The annual

[18] 2019/2020 IRP energy and demand forecast provided to MISO in Nov. 2019 differed slightly in order to match MISO's requirements which necessitated the following an adjustment. It incorporated the 2016 IRP's preferred level of DSM

peak hour is typically between June and September, when weather is hottest. For modeling purposes, Vectren uses August as the peak summer month and January as the peak winter month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.7 – Typical Load Curve Illustrations (Summer and Winter)



This dynamic is evolving as more intermittent renewable resources, particularly solar, come online. MISO nets out energy produced from renewable resources from customer load. This is expected to shift the net peak into the evening hours where dispatchable resources will be needed to serve customer load.

4.8 STAKEHOLDER INPUT – Load Forecast

Vectren discussed the load forecast with stakeholders in the October 10th stakeholder meeting, providing an opportunity to provide input, question and comment on the draft load forecast before finalizing. There was a robust discussion on trended weather projections used in the load forecast. Some stakeholders believed that the trend utilized did not reflect the findings in a recent Purdue University climate study. Vectren reached out to Purdue University and they provided some clarification on the differences between their study and ours, including using different set points for heating and cooling degree days. Itron reviewed and estimated that the HDD trend was the same, while the CDD trend is nearly two times higher in the Purdue dataset. Utilizing the Purdue CDD trend would add approximately 40 MWs to Vectren's forecast over the next 20 years, which was well within Vectren's high bound forecast. Vectren did not update its load forecast, based on this analysis. This was discussed in the December 13, 2020 stakeholder meeting.

SECTION 5
The MISO Market

5.1 MISO

Midcontinent Independent System Operator (MISO), is the independent, not-for-profit Regional Transmission Operator (RTO) of which Vectren is a member. MISO oversees power delivery across 15 states and the Canadian province of Manitoba and is the largest energy and operating reserves market in the world. MISO is divided into 11 Local Resources Zones (LRZ), Indiana is part of Zone 6, which includes northwest Kentucky (Big Rivers Electric Cooperative). Each LRZ has its own planning requirements regarding energy and capacity and can rely on neighboring Zones to an extent, largely depending on transmission infrastructure. Based on MISO's Local Clearing Requirement (LCR), approximately 70% of Vectren's generation must be physically located within MISO Zone 6.

Figure 5-1 – MISO Local Resource Zones



MISO's two main roles are transmission planning and oversight of its energy, capacity and ancillary service markets. MISO has operational authority to control transmission facilities and coordinate security for its region to ensure reliability. MISO is responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load needs.

5.2 MISO Planning Reserve Margin Requirement (PRMR)

MISO requires Vectren and its other member electric utilities to maintain a Planning Reserve Margin Requirement (PRMR). The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in ten years and is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. To further ensure the NERC standard of one loss of load event in ten years, the PRMR is further detailed by the Local Clearing Requirement (LCR) which mandates how much of a Local Resource Zone's (LRZ) PRMR must be met by generation resources physically located within that LRZ. In recent years the amount of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend appears to continue as some baseload units are projected to retire by 2023. As a result, long term dependence on the market for capacity and energy has considerable risk.

The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 5.2 –Illustration of Load Curve and Planning Reserve Margin

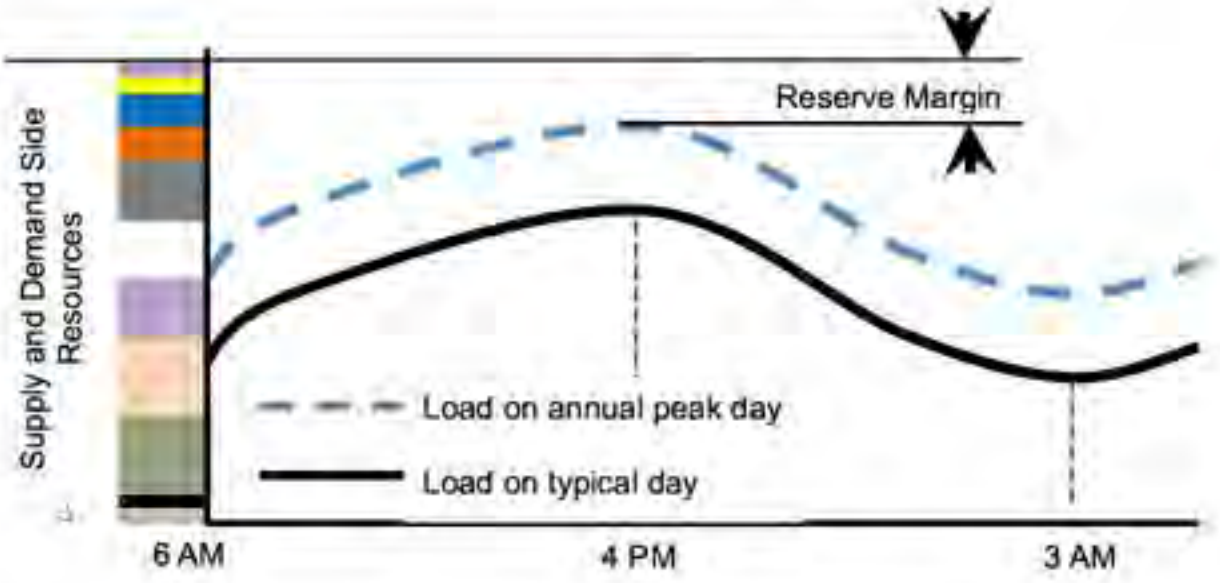


Figure 5.3 –Historic MISO PRMR

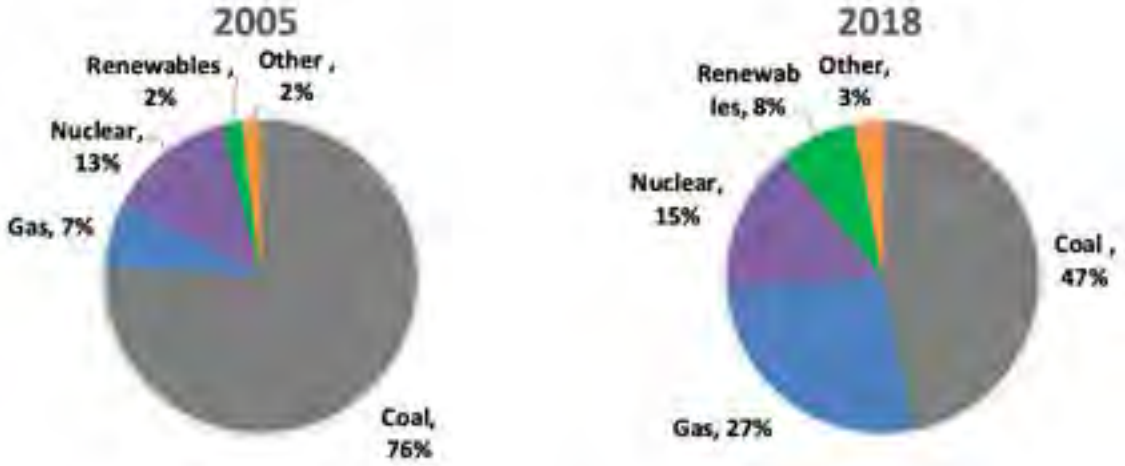
Planning Year	MISO PRMR (UCAP)- Required	MISO PRM (UCAP)- Excess Available:: Offered/PRMR
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: 4.46%
2015-16	7.10%	145,861/136,359: 6.97%

5.3 MISO Resource Mix – Past, Current and Future

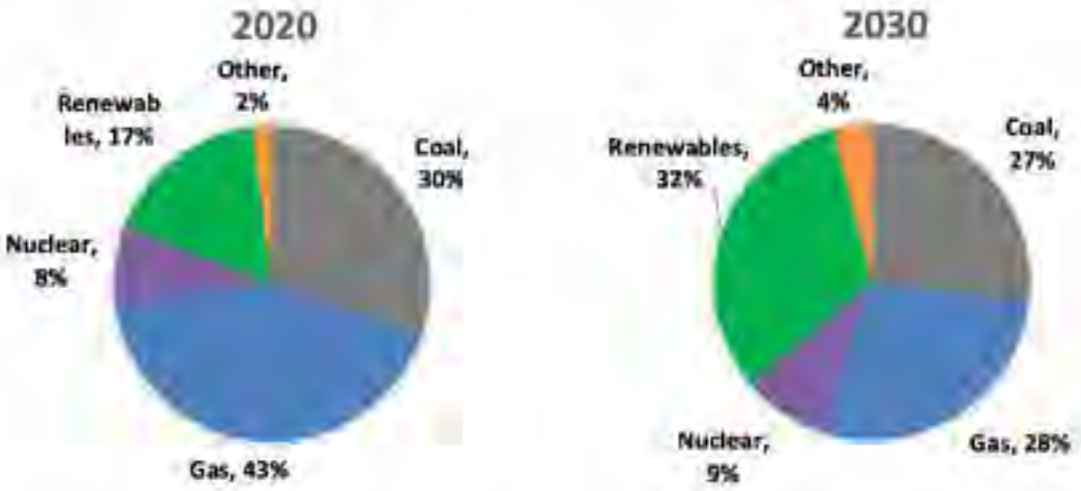
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of the Clean Power Plan and various other regulations and due to cost pressure from low gas price and declining

renewable energy prices, MISO member companies began retiring aging coal units. As a result, its share of the MISO fuel mix dropped to 47%, with natural gas becoming the second leading fuel source and renewables quadrupling in size. This year natural gas (43%) is the leading fuel source in MISO, followed by coal (30%) and renewables (17%), while nuclear has decreased to only 8%. MISO now projects that by 2030 renewables will be the leading fuel source of MISO capacity at 32%, followed by gas at 28% and coal decreasing to 27%.

Figure 5-4 – MISO Fuel Mix[19]



[19] Sources: 2005 Mix: MISO Evolution of the Grid presentation on 11/07/17 https://ecaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf
2018 Mix: MISO 2019 MTEP https://cdn.misoenergy.org/MTEP19%20Executive%20Summary%20and%20Report398565.pdf
2020 Mix: MISO Corporate Fact Sheet accessed 03/20 https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
2030 Mix: MISO RASC Presentation 2020 Focus presented on March, 2020 https://cdn.misoenergy.org/20200304%20RASC%20Item%2002%20RAN%20Overview%20(RASC009%20RASC010%20RASC011%20RASC012)432103.pdf



5.4 Dispatchable vs. Intermittent

Dispatchable generation refers to sources of electricity that can be used or dispatched on demand at the request of the power grid operator. Intermittent generation is associated with renewable forms of electricity, mainly solar and wind, that cannot be dispatched at a moment's notice and without storage capabilities only generate electricity as available. Dispatchability of a generation resource allows for planning that is reflected in capacity accreditation, which provides a generator an annual value based on: expected generation output during peak-load conditions, generator characteristics and the past three years of operational performance. Lack of dispatchability creates planning challenges best illustrated through the recent increase in MISO Emergency Max-Gen Events that have occurred throughout the four seasons as the reliance on intermittent resources has increased. An intermittent resource that may be capable of 100% of nameplate generating capacity on a certain day may be reduced to 0% of capacity during another hour of that same day due to a weather pattern. This volatility of intermittent renewable resources has challenged grid planners as these resources have been added to the system. Dispatchable resources that are not on outage remain available as called upon during these severe conditions when intermittent resources do not meet planned output.

MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 83% currently and is forecasted to be at 60% in

2030. In response to these conditions MISO commenced its Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) to plan market rule changes to deal with the future resource mix. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them.

5.5 MISO Maximum-Generation Emergency Events

Maximum-Generation (Max-Gen) Events are the final step in MISO's emergency operating procedure before firm-load shed, otherwise known as blackouts. Max-Gen Events have historically been rare in nature, with MISO experiencing 3 events between 2009 to 2015 and they occurred only during peak load condition summer months. However, since 2016 there have been 10 events, spanning all four weather seasons. In January of 2019, MISO, for the first time in its existence, interrupted energy service to Industrial Customers enrolled as Load Modifying Resources (LMR). Going forward customers enrolled as LMRs must consider the increased possibility of future interruptions. It is likely that some LMRs will end their participation due to the heighted risk.

5.6 MISO Resource Adequacy Reform

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, MISO implemented its RAN initiative. The goal of this initiative is to "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region."

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[20] that are high priority that include Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events, increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold, instituting a Seasonal Planning Resource Auction construct, which would break up the current annual capacity auction to seasonal auctions that would adjust the PRMR and capacity accreditation for resources during these periods. Vectren considered the potential for winter and summer accreditation.

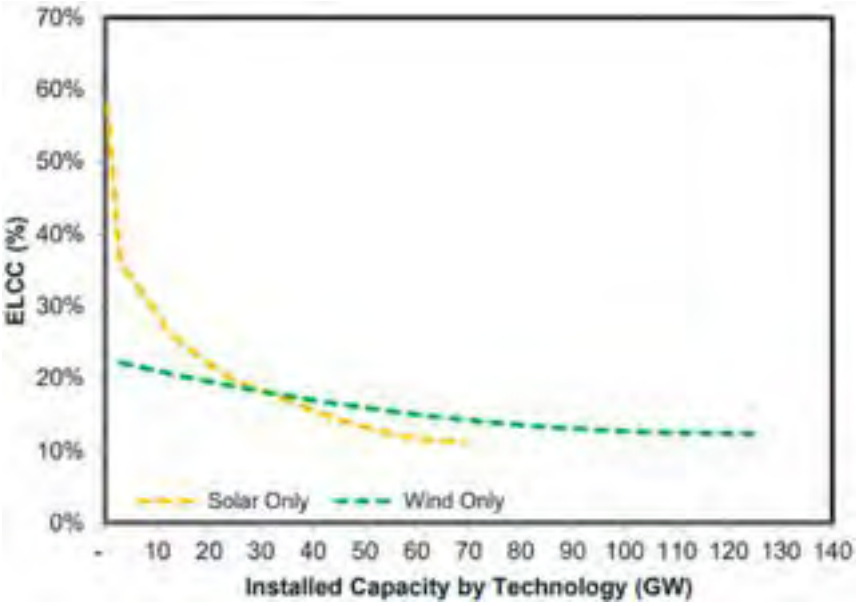
5.7 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit towards MISO's resource adequacy requirement based on their ability to reliably contribute energy at the peak demand hour. Thermal generation, such as natural gas and coal-fired power plants, can produce an expected level of output when called upon. For this reason, utilities can count nearly the full installed capacity of thermal generation towards their resource adequacy requirement (less their historical outage rate). A new thermal generator can count ~96 MWs out of every 100 MWs of installed capacity towards meeting MISO's summer planning reserve margin requirement. This amount increases in the winter for gas resources due to air density in cold weather conditions. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Because neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, they receive less capacity credit.

[20] MISO 2019 Market Roadmap: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

While renewable wind resources produce a lot of renewable energy over the course of the Planning Year, their capacity accreditation is typically a lot lower than dispatchable generation. MISO calculates the capacity which will be accredited for wind resources by calculating the resources' Effective Load Carrying Capability (ELCC). Wind resources located in MISO Zone 6 received a capacity credit of only 7.8% for MISO's 2019-2020 planning year, meaning for every 100 MWs of installed wind capacity, 7.8 MWs would count towards meeting MISO's planning reserve margin. As part of MISO's RIIA, MISO evaluated the ELCC of wind and solar resources as penetration levels increased. Renewable penetration is expected to increase as shown in Figure 5.4. Renewable penetration increasing results in the net peak load shifting. This shift results in lower renewable energy production coincidence with the net peak load and therefore a lower ELCC accreditation as seen in Figure 5-5.

Figure 5-5 Decreasing solar and wind ELCC as more is installed[21]



[21] Renewable Integration Impact Assessment (RIIA) Assumptions Document Version 6, December 2018, MISO, page 11, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

The solar and wind accreditation used in the IRP modeling was calculated using MISO's ELCC accreditation formulas and adjusted based upon the level of renewable penetration expected on MISOs system. As additional renewable resources were included in the model the UCAP accreditation for these resources was revised. Over time, this results in a lower accreditation value as additional resources come online.

While MISO's current methodology for determining resource adequacy only considers the summer peak, they have begun to discuss the inclusion of other seasons. Wind and solar capacity factors and energy coincidence with the net peak load vary seasonally. A Solar PV production chart comparison for the winter and summer is shown in Figure 5-6. It shows solar output has a higher coincident with peak demand in the summer months than winter months, due to not only the lower winter solar production, but also the typical peak demand occurring later in the day. These combined effects result in lower solar winter capacity accreditation. Wind resources typically have higher capacity factors during winter months leading to a higher output during winter peak demand hours. Summer and winter wind production compared to load shape are shown in Figure 5-7 gas resource or other dispatchable generation, benefits from being able to turn on and off as needed with exception to unit outages and therefore have higher capacity accreditation than non-dispatchable intermittent resources. For reference, a typical gas resource seasonal capability difference is shown in Figure 5-8.

Figure 5-6 Average Solar PV energy production summer versus winter

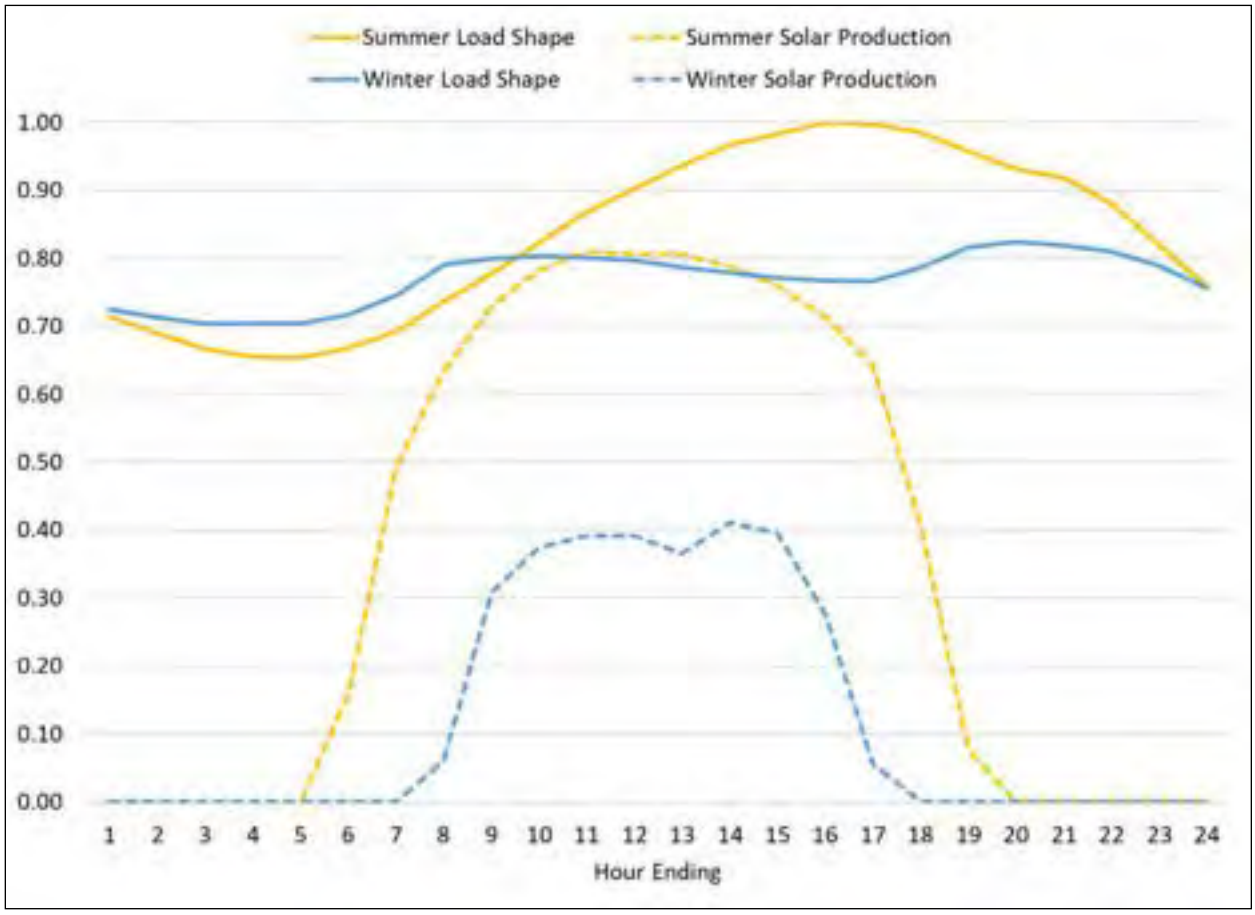


Figure 5-7 Average Wind energy production summer versus winter

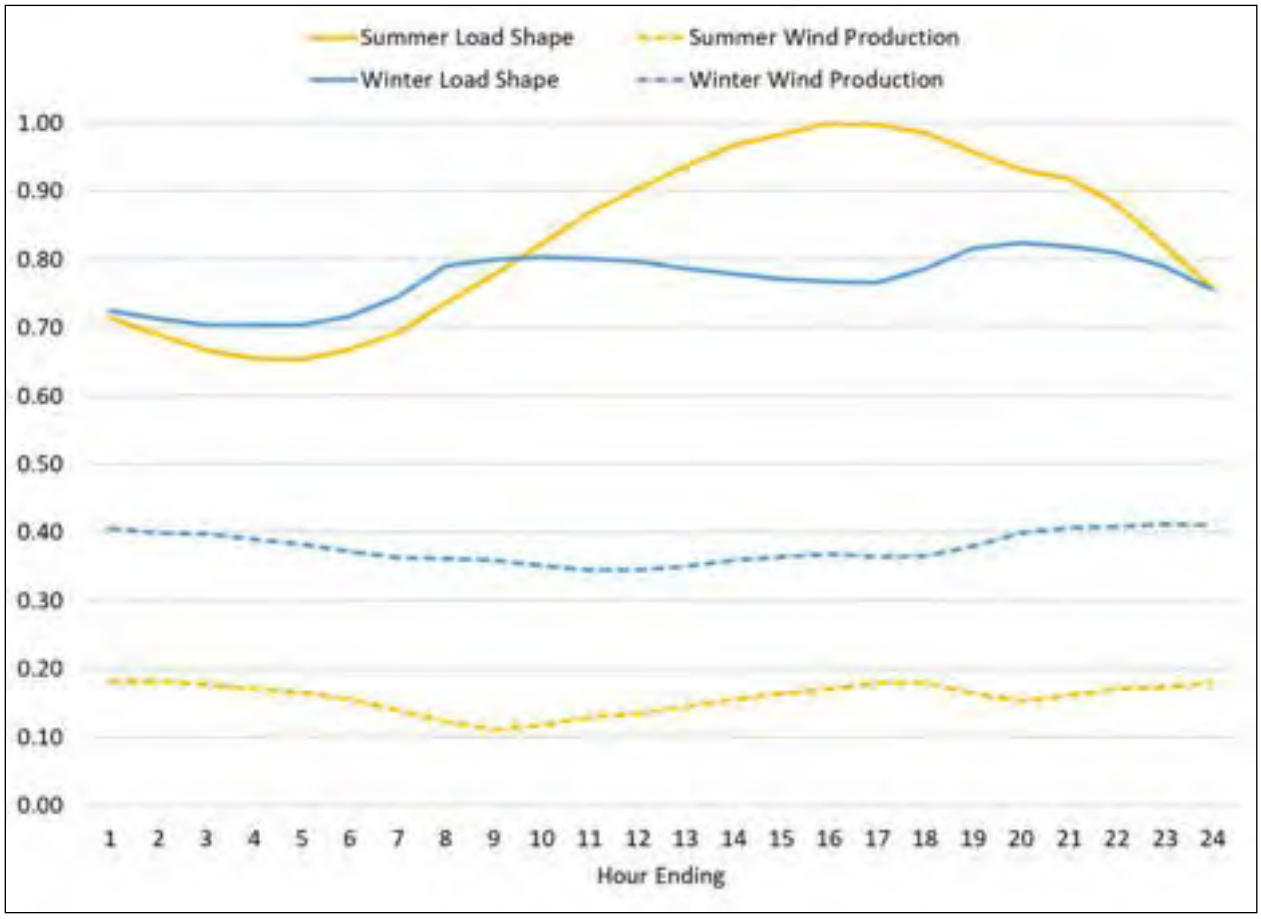
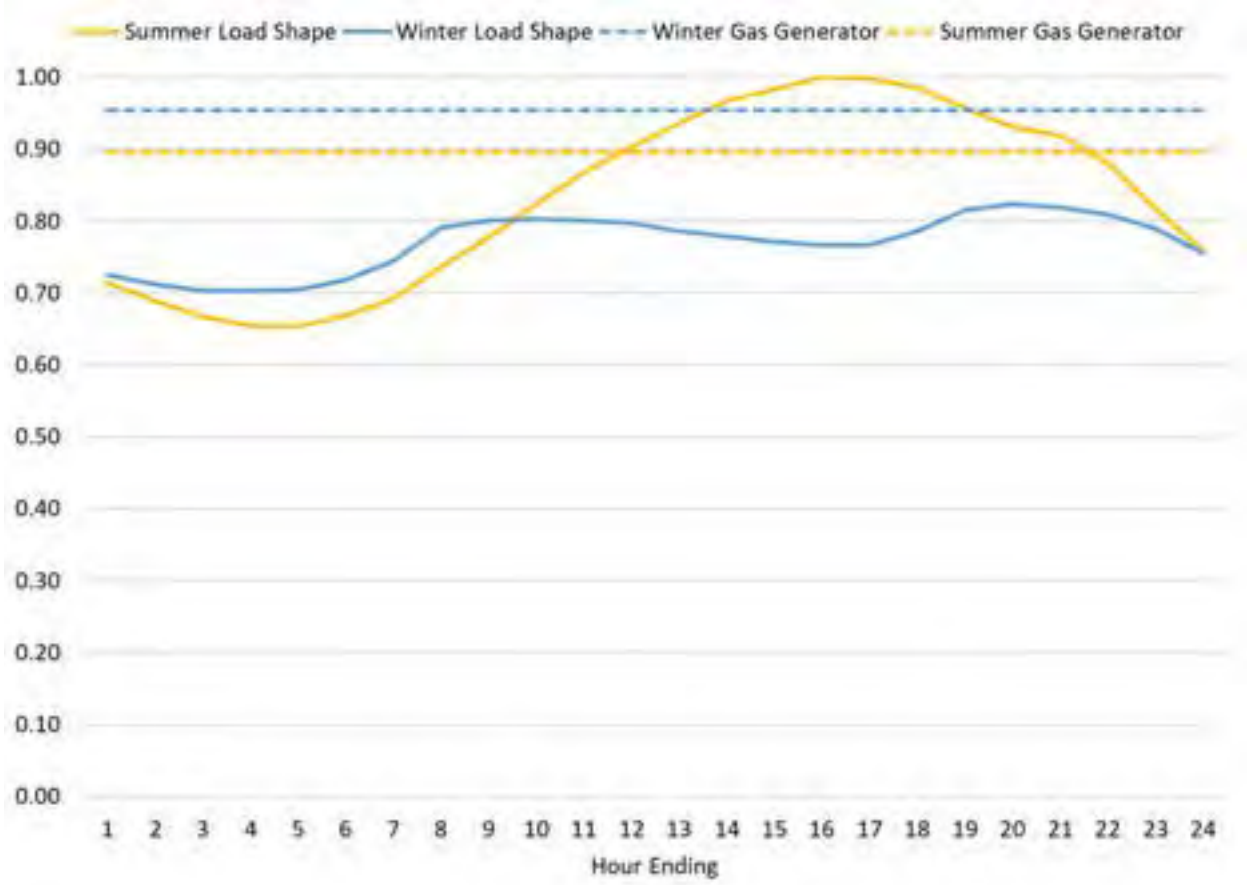


Figure 5-8 Average Gas Resource energy potential summer versus winter



MISO has already implemented seasonal coordinated maintenance schedule reporting. Additionally, MISO currently is considering implementing a seasonal construct to capacity accreditation. Based on recent MISO publications, discussions and input, this likely could be a four-season construct which is planned to be implemented as soon as 2022. Publicly posted feedback from MISO stakeholders and MISO indicated accreditation should vary by season and reflect expected availability of resources in each season. Vectren is a member of MISO and as such cannot ignore nor avoid updates to MISO's accreditation process. Vectren has utilized a conservative summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation.

5.8 MISO Capacity

Historically, the price for capacity in MISO's annual auction has been volatile. The Organization of MISO States (OMS), of which the IURC is a participant and MISO teamed together to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has served as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and is a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned that there may be inadequate capacity within the MISO footprint at some future date. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. Figure 5.9 below illustrates Zone 6's increasing proportion of the entire MISO region shortfall projection and thus increased reliance on neighboring state generation resources. Over the years, the OMS and MISO have updated the methodology to project simply which resources are considered high certainty in hopes of increasing the accuracy of the projection. With these improvements in place since 2017, there is still a projected shortfall. This shortfall is concerning, especially from a zonal standpoint that shows certain zones relying heavily on other zones to meet the overall MISO capacity requirement. The latest OMS survey shows IN Zone 6 as one of the zones most at risk of a shortfall, with a deficit projected to surpass the entire MISO region's deficit. It is worth noting that since 2016 Indiana's Zone 6 has imported capacity to meet its PRMR needs. This means based on current MISO member plans and expectations, Zone 6 is expected to continue importing energy to meet a substantial amount of its needs through the year 2025, the last year of the survey period. This potential long-term reliance on the market makes Zone 6 and Vectren's customers susceptible to volatility in the auction clearing price and the resource adequacy policy and decisions of neighboring Zones. The table below demonstrates that

since 2018 the MISO region has cut its projected shortfall in half, while Zone 6's shortfall has almost doubled.

Figure 5.9 – OMS-MISO Resource Adequacy Survey Results

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, 5-Year Projected	MISO-wide Resource Adequacy Shortfall, 5-Year Projected
2014	No 5-year projection provided	5.8 GW shortfall in 2019
2015	1.1 GW shortfall in 2020	2.3 GW shortfall in 2020
2016	800 MW shortfall in 2021	2.6 GW shortfall in 2021
2017	400 MW shortfall in 2022	No shortfall projected
2018	1.6 GW shortfall in 2023	4.5 GW shortfall in 2023
2019	2.4 GW shortfall in 2024	2.3 GW shortfall in 2024

5.8.1 Capacity Prices

The projected capacity shortfalls can result in volatile capacity prices. MISO's Planning Resource Auction (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 5.10 below. These large swings in prices have made it difficult to forecast forward year prices. While the 2020-2021 capacity price was relatively low, neighboring Zone 7, which consists of the lower peninsula of Michigan reached the Cost-of-New-Entry (CONE) rate, which is approximately $257, or ~50 times higher than the $5.00 clearing price. Michigan very narrowly missed cone in the 2019-2020 planning year. Since then, MISO updated market rules to ensure only units that enter the auction will be available at the time of need, the likelihood of price increases intensifies.

Figure 5.10 – MISO Capacity Prices

Planning Year	Highest Clearing price for MISO-region	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[22]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$1.05	$383.25	-
2014-2015	$16.75	$16.75	$6,113.75	1495% Increase
2015-2016	$150.00	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$72.00	$26,280.00	1969% Increase
2017-2018	$1.50	$1.50	$547.50	98% Decrease
2018-2019	$10.00	$10.00	$3,650.00	567% Increase
2019-2020	$24.30	$2.99	$1,091.35	70% Decrease
2020-2021	$257.53	$5.00	$1,825.00	67% Increase

5.9 MISO Energy Prices

Energy prices in MISO have decreased in the last 18 months and are at all-time lows. The main driver of the price decrease is tied to the marginal generation units that set the energy price. Natural gas and renewables have shifted the marginal generation mix from coal to natural gas. Even prior to COVID-19, Natural gas prices were at historic lows, recently in the $2 range due to increased U.S. and global production and warmer than normal winter weather causing an oversupply, which has lowered the operating costs of natural gas generation. This has lowered the bids of generation in the MISO market and led to lower clearing prices as depicted below:

[22] MW/day is the amount customers are required to pay should they purchase capacity via the MISO Planning Resource Auction. For example, in the 2016-2017 planning year each MW cost $72 per day ($26,280 per MW annually).

Figure 5.11 – MISO Clearing Prices

Indiana Hub/Henry Hub Yearly Averages
2015 - YTD Apr. 2020

Year	Indiana Hub Real Time ATC Average	YoY% Change	Indiana Hub Day Ahead ATC Average	YoY% Change	Henry Hub Average	YoY% Change
YTD 2020	$21.02	-20.39%	$21.60	-19.81%	$1.83	-27.05%
2019	$26.41	-19.95%	$26.98	-18.72%	$2.51	-19.41%
2018	$32.99	12.59%	$33.19	12.97%	$3.12	5.36%
2017	$29.30	4.86%	$29.38	4.50%	$2.96	19.10%
2016	$27.94	-0.27%	$28.11	-1.94%	$2.49	-4.60%
2015	$28.02		$28.67		$2.61	

Over time, it is expected that natural gas prices will increase, but remain low and stable, keeping energy prices low.

5.10 MISO Interconnection of New Resources

Before a new generating facility can connect to the grid, the reliability impacts associated with interconnection must be studied. Issues uncovered during this process can be mitigated through electric transmission Network Upgrades (NU). The addition of upgrades to address system reliability have the potential to increase the costs associated with a new generating facility. Each of the All-Source RFP proposals were analyzed to determine its associated impacts to the transmission system as well as the associated Network Upgrade costs.

The MISO Generator Interconnection (GI) process is a three-phase study cycle that has been conducted twice annually (recent schedule is reduced to once per year) to study the impact and any associated transmission system upgrade costs as a result of new generation connecting to the MISO transmission system. Usually there is a study cycle in the 1st quarter and 3rd quarter of each year. Application and milestone payment requirements based on the size of the unit to be studied are required 45 days prior to the start of the study cycle. These two study cycles are the only two periods in which to enter

the GI queue each year. Mid-year and mid-queue requests are not allowed. After all modeling details are finalized the study enters the Definitive Planning Phase (DPP). The DPP is broken into three phases that are restudies based on immaterial changes to generator attributes and the removal of projects that decide not to proceed to the next study phase. Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement (GIA) process. Upon 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.

MISO estimates the process to take 505 days, start to finish. However, with the record amount of interconnection requests that MISO has seen in the last two years, the process is averaging over 2 and a half years per MISO's DPP schedule update posted 3/1/2020. As increased renewable development continues in order to qualify for tax incentives before expiration, the number of GI requests is not expected to subside and as a result, the timeline is likely to remain delayed.

GI costs are determined based on the MW impact from each project on identified constrained facilities. As such, cost allocation is assigned to the generator that causes or contributes to a constraint and therefore projects that are studied after prior cycles are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying after prior cycles are more likely to be assigned higher costs as a result of prior projects connecting to and exhausting current transmission system topology. For this reason, existing interconnection rights at the Brown site are valuable. MISO allows for an expedited process for new generation with existing interconnection rights; this helps to shield customers from potential upgrade costs should Vectren enter the MISO queue at another site.

SECTION 6
RESOURCE OPTIONS

6.1 ALL SOURCE RFP

The All-Source RFP was conducted according to the schedule outlined in Figure 6-1. More details on the steps included in the RFP timeline are described below.

Figure 6-1 RFP Timeline

Step	Completed/Proposed Date
RFP Issued	Wednesday, June 12, 2019
Notice of Intent, RFP NDA and Respondent Pre-Qualification Application Due	5:00 p.m. CDT, Thursday, June 27, 2019
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. CDT, Wednesday, July 10, 2019
Proposal Submittal Due Date	5:00 p.m. CDT, Friday, August 9, 2019
Initial Proposal Review and Evaluation Period	Friday, August 9, 2019 – Wednesday, September 18, 2019
Proposal Evaluation Completion Target and Input to Vectren	2nd Quarter, 2020
Due Diligence and Negotiations Period	Mid 2020
Definitive agreement(s) Executed (subject to regulatory approvals) with Selected Respondent(s)	Late 2020
Petitions (if required) filed with the IURC, the Federal Energy Regulatory Commission (FERC), or any other required agency/commission	TBD

6.1.1 RFP Issued

Burns & McDonnell issued the All-Source RFP on behalf of Vectren on Wednesday, June 12, 2019 (http://vectrenrfp.rfpmanager.biz/default.aspx). Notice was sent to all known IRP stakeholders and posted on www.vectren.com/IRP. The RFP was advertised across multiple media outlets, including Megawatt Daily (~20,000 recipients), North American Energy Markets Association (NAEMA) (150 members) and Midwest Energy Efficiency Alliance (MEEA) Minute (161 members). It was also sent directly via e-mail to participants of Vectren's 2017 RFP, an internal Burns & McDonnell RFP contact list (>450 industry

contacts) and Vectren industry contacts. While the RFP included general requirements and communicated that Proposals which do not meet the general requirements may be subject to disqualification, all were included for evaluation. For more details please refer to the submitted Vectren 2019 All-Source RFP in Technical Appendix Attachment 6.3.

6.1.2 Notice of Intent

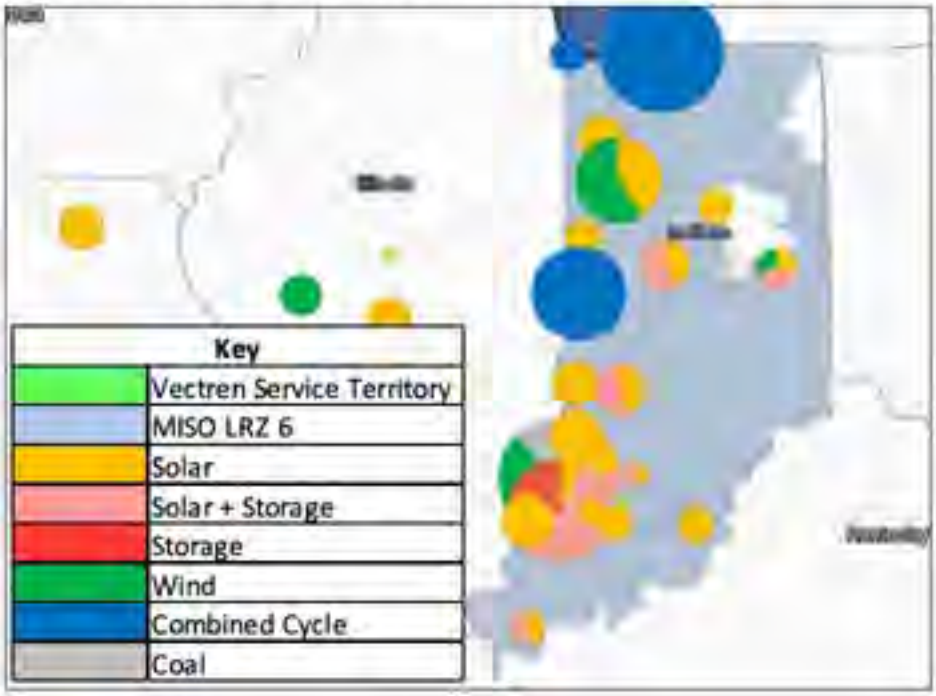
Respondents were given more than two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify that Respondents have adequate experience and financial capability to support their Proposal(s).

6.1.3 Proposal Review

The Proposal Submittal Due Date was Friday, August 9, 2019. After all Proposals had been received, Burns & McDonnell began the Initial Proposal Review. While Proposals were being reviewed, information was clarified with Respondents to confirm Proposals were interpreted as intended.

A total of 110 Proposals were received from 22 Respondents. The Proposals comprised eight battery storage, two coal, seven combined cycle gas, one LMR/DR, 57 solar, 19 solar plus storage, three system energy and 13 wind. Of the 110 Proposals, 91 were in Indiana. The Proposals contained approximately 21 GW of total installed capacity; however, many of the projects were included in multiple proposals. There was approximately 10 GW of unique project installed capacity after accounting for double counting. For example, a single 100 MW wind farm project could be offered as a purchase option or various PPA options. A graphical overview of all Proposals received is shown in Figure 6-2.

Figure 6-2 Map of Proposals Received



6.1.4 MISO Interconnection

The appropriate MISO DPP Generation Interconnection Study Group was identified for each of the respective Proposals. For the Proposals that reside in Study Groups with posted DPP reports, the identified NU and associated costs were used.

For the proposals that reside in Study Groups without posted DPP reports, Burns & McDonnell performed a steady state analysis using the appropriate DPP Study Group cases and auxiliary files. These selections were evaluated against the impact criteria defined in Section 6.1.1.1.8 of MISO's BPM-015 (Business Practices Manual), including the cumulative impact criteria.

Finally, for those selections that have not entered the queue or did not have a DPP Study Group case available, the most recent DPP Study Group case was used for the

evaluation. The same impact criteria were applied with the exclusion of the cumulative impact criteria.

Figure 6-3 - RFP Project Definitive Planning Phase (DPP) Study Groups

Number of RFP Projects in DPP Study Group	Study Group	Network Upgrade (NU) Cost From:	Burns and McDonnell Action:
1	DPP-2016-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm Generator Interconnection Requests (GIRs) sharing allocations are active.
1	DPP-2016-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
4	DPP-2017-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
10	DPP-2017-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
5	DPP-2018-APR Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
1	DPP-2018-APR West	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.
18	DPP-2019-Cycle1 Central	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.

For any impacts reported, without any information on the limitation of the facility, Burns & McDonnell assumed a full rebuild scope and cost of the facility. NU costs for the reported impacts were developed using MISO's MTEP transmission cost estimation guide. These NU costs were considered for the evaluation of each proposal. Many Proposals included allowances for NU costs or indicated all NU were included in their Proposal and these nuances were accounted for during the analysis.

6.1.5 Grouping

Proposals were divided into groups based on characteristics such as technology type, ownership structure and contract duration. Aggregated cost and performance information from the RFP Proposals was provided to the IRP team to facilitate portfolio modeling. There are many benefits to modeling the RFP bids in Groups. These benefits include allowing the IRP modeling to help evaluate the technology, size, duration and mix of resources which would be included in the Preferred Portfolio. Given the volume of proposals received as part of the IRP, it may not have been possible and would not have been practical to model each individual project. Moreover, it would be difficult to maintain confidentiality of individual projects. IRP modeling of individual projects does not holistically evaluate all relevant factors, such as locational differences of wholesale market pricing and potential congestion impacts. Using a grouping method allows for IRP inputs to reflect anticipated project costs.

Proposals were divided into two tiers, based on factors that could add cost risk to Vectren customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW (Vectren's load node) or were physically located in Vectren's service territory. Tier 2 included the remaining Proposals that were not classified as Tier 1. Tier 2 Proposals generally did not provide a binding bid price and/or were located off Vectren's system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, Vectren wanted, to the extent possible, to include bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Seventeen (17) groups were formed. This resulted in data from 49 Tier 1 Proposals being used in IRP analysis. A summary of the Proposal grouping is shown in Figure 6-4. As seen in Figure 6-4, the energy-only Proposals were not put into a group because they did not meet the capacity requirement of the RFP. Due to a high quantity of bids in the group and to provide additional granularity in IRP modeling, groups 15 and 17 were split into high and low-cost groups.

Figure 6-4 Proposal Grouping

Grouping		RFP Count	Tier 1	Tier 2
1	Coal PPA	2	0	2
2	LMR/DR PPA	1	1	0
3	CCGT PPA	2	0	2
4	CCGT Purchase	5	0	5
5	Wind Purchase	2	0	2
6	12-15 Year Wind PPA	9	4	5
7	20 Year Wind PPA	2	1	1
8	Storage Purchase	4	4	0
9	Storage PPA	4	4	0
10	Solar + Storage PPA	6	5	1
11	Solar + Storage Purchase	9	5	4
12	Solar + Storage Purchase/PPA	4	1	3
13	Solar Purchase/PPA	6	1	5
14	12-15 Year Solar PPA	8	3	5
15	20 Year Solar PPA	16	10	6
16	25-30 Year Solar PPA	9	3	6
17	Solar Purchase	18	7	11
N/A	Energy Only	3	0	3
	Total	**110**	**49**	**61**

The costs for Tier 1 Proposals are outlined in Figure 6-5. Costs were not shown for groups that contained only one project to ensure confidentiality.

Figure 6-5 - Tier 1 Cost Summary[23]

	Group	# Proposals	# Projects	Proposal ICAP (MW)	Project ICAP (MW)	Capacity Weighted Average LCOE ($2019/MWh)	Capacity Weighted Purchase Price ($/kW)[2]
1	Coal PPA	0					
2	LMR/DR PPA	1	1	50	50		
3	CCGT PPA	0					
4	CCGT Purchase	0					
5	Wind Purchase	0					
6	12-15 Year Wind PPA	4	1	800	200		
7	20 Year Wind PPA	1	1	300	300		
8	Storage Purchase	4	2	305	152	$157	
9	Storage PPA	4	2	305	152	$135	
10	Solar + Storage PPA	5	3	902	526	$44	
11	Solar + Storage Purchase	5	3	862	486	TBD[1]	$1,417[3]
12	Solar + Storage Purchase/PPA	1	1	110	110		
13	Solar Purchase/PPA	1	1	80	80		
14	12-15 Year Solar PPA	3	2	350	225	$32	
15	20 Year Solar PPA	10	8	1,522	1,227	$35	
16	25-30 Year Solar PPA	3	2	400	275	$34	
17	Solar Purchase	7	6	902	732	TBD[1]	$1,262

1. The method for realizing tax incentives is being reviewed by Vectren
2. $/kW costs are in COD$, purchase option cost is the purchase price unsubsidized by applicable tax incentives and does not reflect ongoing operations and maintenance costs
3. Cost based on simultaneous MW injectable to the grid

6.1.6 Evaluation of Proposals

Burns & McDonnell quantitatively and qualitatively evaluated all conforming generation facility Proposals. Proposals were evaluated relative to others within the same grouping

[23] Note that proposals based on one project do not include capacity weighted Average LCOE or Capacity Weighted Purchase Price to maintain confidentiality of the bid.

using the scoring criteria set forth in the RFP. The scoring criteria included four major categories: LCOE, energy settlement location, interconnection/development status and local clearing requirement and project risk factors.

Scoring of the individual RFP Proposals was not part of the IRP process. Scoring criteria has been provided for transparency to respondents and to demonstrate that Vectren is serious about pursuing projects following the completion of the IRP analysis. Vectren does not believe that RFP's should be conducted just to obtain market data. The Proposals were scored to aid in the selection process after the preferred portfolio results were provided from the IRP. The Proposals were scored according to the criteria shown in Figure 6-6.

Figure 6-6 Scoring Summary

Scoring Criteria Name	Points		Scoring Method	Definition	Importance
LCOE Evaluation	150		Curve	$/MWh calculation within asset class	An LCOE evaluation comparing similar resource groups will help to show which Project(s) may provide lower cost energy to Vectren's customers.
Energy Settlement Location	100		Binary	Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW)	Having financial settlement or direct delivery to Vectren's load node provides Project's true resource cost to Vectren's customers, eliminating risks/costs associated with the delivery of energy.
Interconnection and Development Status	60		Binary	Executed a pro-forma MISO Service Agreement and Interconnection Construction Services Agreement (12 points) Completed a MISO Facilities Study (12 points) Completed a MISO System Impact Study (12 points) Achieved site control and completed zoning requirements (12 points) EPC Contract awarded (12 points)	These points are for completion of various critical milestones in the interconnection and development process. Projects which are further through the interconnection and development process will receive more points as cost certainty improves.
Local Clearing Area Requirement	30		Binary	Physically and electrically located in LRZ 6	Being located in LRZ 6 provides greater certainty that asset capacity can be deliverable to Vectren and fall within LCR requirements through entire life or contract term.
Credit and Financial Plan	20		Curve	Vectren will be reviewing the credit rating and financing capabilities in relation to a Bidder's Project.	Projects which lack the financial wherewithal to ensure development pose a significant risk to Vectren and their customers.
Development Experience	20		Curve	Scored based on 1,500 MW of relevant development experience	Relevant technology experience is important when looking at asset purchases or PPA's for facilities which are not in service. A Bidder's track record of project completion is a benefit to the Project's scoring.
Sole Ownership/Partial Owner	20		Binary	Being a sole owner would allow full site and dispatch rights/preferences	Being able to solely own, operate, and maintain a Project lowers risks for Vectren and their customers.
Ownership Structure (Purchase/PPA)	20		Binary	Vectren has a preference for ownership	Owning an asset and having control with regards to dispatch, maintenance, and operation of the facility lowers risks for Vectren and their customers.
Operational Control	20		Binary	Dispatch parameters used for the scheduling of energy into MISO and approval for maintenance outage periods	Operational control provides the ability to make prudent operational decisions when it makes economic sense for Vectren's customers.
Fuel Risk	20		Binary	Sites having firm and reliable fuel supply	Having fuel restrictions or a lack of reliable fuel could effect the operation of the Project and be a risk to the owner/off taker.
Delivery Date	20		Curve	For each year prior or after MISO PY 2023/2024, 25% of the points will be deducted	To the extent resources are brought on-line before potential Vectren unit retirements, Vectren customers could pay for duplicative capacity and/or energy; while there may be reasons to proceed with such projects, in recognition of their incremental costs, it is appropriate for such projects to not score as well in terms of timing.
Site Control	20		Binary	Proper rights to the site in which the facility will be located	Without proper permitting and permissions from the owner, there is a risk that the project may not move forward or could experience significant delays.

RFP bids were rank ordered consistent with the evaluation criteria and will be considered based on the RFP evaluation and the IRP determined need. Projects consistent with the

IRP have undergone further due diligence and have led to negotiations with bidders. As such, there is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected. For further discussion of the evaluation criteria and results see Technical Appendix 6.9.

6.1.7 Challenges with Conducting an All-Source RFP within an IRP

While there are advantages to conducting an All-Source RFP as part of the IRP process, there are several challenges that must be considered, particularly the long lead time. Developers prefer certainty on project selection to minimize project development cost risk. Conducting an RFP as an input to the IRP necessitates a long process. Vectren believes that, at a minimum, a year is needed to conduct an IRP analysis. While Vectren asked bidders to keep bids open for a year after bid submittal, this does not mean that developers are able to wait until the process is complete.

As a result, some bids were withdrawn from Vectren's RFP during the IRP because the projects were acquired by other load serving entities. This delay has hurt the ability to act on proposals before they are acquired. During this IRP, at least one project, was purchased by another utility. Competition for projects in MISO zone 6 is steep with many utilities (NIPSCO, IPL, Hoosier Energy, IMPA and Vectren) currently all vying for announced projects that have more certainty of being developed.

Vectren has also had several attractive local wind and solar projects drop out of the MISO Generation Interconnection queue due to commitments/costs required from interconnection studies and they are no longer available at this time. Often projects are speculative. Developers apply with MISO to develop a project and are put in the MISO queue, as a series of studies is conducted. Each study requires more money from the developer in the form of milestone payments. Early studies put less money at risk for the developer. As interconnection costs for a project are identified the developer must make

a choice to stay in the queue or drop out. Without certainty of an off taker, many projects drop. Long lead times increase this risk.

Additionally, some initial cost estimates have proved to be too low. As a project moves along, several issues can arise, including: updated engineering identifying new costs, environmental permitting, local pushback, local permitting, updated interconnection costs, updated risk assessments by the developers, etc.

6.2 CURRENT RESOURCE MIX

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. Vectren's larger coal units have historically operated as base load units but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. Vectren's coal units more recently have operated more like intermediate units, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. Vectren'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, Vectren's gas turbines 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.

Vectren's current generation mix consists of approximately 1,280 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal-fired generation, 160 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 4 MW of solar, Purchase Power Agreements (PPA's totaling 80 MW from wind) and a 1.5% ownership share of Ohio Valley Electric Corporation (OVEC) which equates to approximately 32 MW.

Figure 6.7 below references both Installed Capacity (ICAP) and Unforced Capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO UCAP planning reserve margin requirements (8.9% PRM[24]) in the current IRP. This information was utilized to help ensure that all portfolios met MISO obligations on a seasonal basis.

Figure 6.7 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 1	245	197	235	Coal	1979
A.B. Brown 2	245	232	221	Coal	1986
F.B. Culley 2	90	85	84	Coal	1966
F.B. Culley 3	270	261	263	Coal	1973
Warrick 4	150	133	137	Coal	1970
A.B. Brown 3	80	73	90*	Gas	1991

[24] Planning Year 2020-2021 Load of Load Expectations Report; MISO; https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf; 11/01/2019; page 5

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 4	80	72	82*	Gas	2002
Blackfoot	3	N/A[25]	N/A[26]	Landfill Gas	2009
Oak Hill Solar	2	N/A[22]	N/A[25]	Sun	2018
Volkman Road Solar	2	N/A[25]	N/A[25]	Sun	2018

*Installed capacity shown at 59°F, winter UCAP shown at 20°F

6.2.1 Coal

The A.B. Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986. Over the last three years these units have operated at an average capacity factor of 53%.

Both A.B. Brown units are scrubbed for sulfur dioxide (SO_2) emissions, utilizing a dual-alkali Flue Gas Desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide (SO_3) is removed via Sodium Based Sorbents (SBS) injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides (NO_x) with Selective Catalytic Reduction (SCR) systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is captured via an electrostatic precipitator (ESP) on Unit 2. PM control at Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly

[26] The Blackfoot landfill gas generator and 2 MW solar installations are connected at the distribution level and are not part of the transmission connected generation network managed by MISO. Therefore, they are not assigned a MISO UCAP value.

ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

While the A.B. Brown units began commercial operation after the Culley units, the dual-alkali scrubbers on these units present several operational challenges. First, based on historical costs the variable production cost associated with the scrubbers is approximately six times greater than the limestone-based scrubber installed on the Culley units. Also, the dual-alkali process is corrosive which results in high maintenance costs to keep the FGD's and associated equipment operational. And finally, these FGD's are the last dual-alkali scrubbers in operation in the U.S. and are nearing the end of their useful life. This can lead to challenges obtaining operational support and replacement parts when needed.

A.B. Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, IN and is delivered via rail.

The A.B. Brown plant site also has two natural gas turbine generators which are discussed in Section 6.2.2, Natural Gas.

The F.B. Culley Generating Station (FBC), located near Newburgh, IN, is a two-unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973. Over the last three years Unit 2 has operated at an annual capacity factor of 23% while Unit 3 was 65%.

FBC is scrubbed for Sulfur Dioxide (SO_2) emissions, utilizing an FGD process which is shared by both units and was retrofitted in 1994. This standard technology is much more cost effective than A.B. Brown's scrubber. The captured SO_2 is converted into synthetic gypsum within the system and, as part of Vectren's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, LA and is shipped via truck to a facility near

Shoals, IN where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed from FBC Unit 3 via a Dry Sorbent Injection (DSI) system installed in 2015. FBC Unit 3 is also scrubbed for NO_x with a Selective Catalytic Reduction (SCR) system that was installed in 2003. NO_x control on FBC Unit 2 is provided by low NO_x burners. Mercury removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP retrofitted on Unit 2 in 1972. Unit 3 was upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

The F.B. Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck. F.B. Culley 3 is Vectren's most efficient coal unit with an industry standard scrubber, which has much lower variable costs than ABB1 and ABB2. As such F.B. Culley 3 is in the process of upgrades to comply with EPAs ELG rule.

Warrick Unit 4 (Warrick) located near Newburgh, IN is a coal fired unit operated and maintained by Alcoa Power Generating Inc. Vectren maintains 50% ownership of Warrick Unit 4. It has an installed capacity of 300 MW which began commercial operation in 1970. Vectren's 50% interest is equal to 150 MW. Over the last three years this unit has operated at a capacity factor of 62%.

Warrick Unit 4 is scrubbed for SO_2 emissions, utilizing a FGD process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system and (as part of Vectren's beneficial reuse program) is shipped via truck to a facility near Shoals, IN where it is used in the manufacture of drywall. SO_3 is removed via a DSI system installed in 2010. Unit 4 is also scrubbed for NO_X with a SCR system which was retrofitted in 2004. Mercury removal is accomplished as a co-benefit of SCR and FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP. The PM that is captured, also known as fly ash, is part

of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

Warrick Unit 4 burns Illinois basin bituminous coal. Vectren purchases coal for its share of Warrick Unit 4, which is mined in Knox County, IN and is delivered by rail.

6.2.2 Natural Gas

The A.B. Brown Generating Station has two natural gas fired Simple Cycle Gas Turbine (SCGT) peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002. Over the last three years Unit 3 has operated at a capacity factor of 1% with Unit 4 at 2%.

6.2.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN is a base load facility consisting of two Internal Combustion (IC) landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each. Over the last three years these units have operated at a capacity factor of 42%.

The Oak Hill and Volkman Road universal solar projects in Evansville, IN became operational in 2018 with each location having an installed solar capacity of 2 MW. In addition to the solar capacity the Volkman Road site includes 1 MW of battery storage. These assets are located on the distribution system and are therefore netted out of Vectren load for this analysis. In 2019 the solar installations operated at an average annual capacity factor of 21%. The average annual capacity factor is affected by hours of daylight, cloud cover, temperature, etc. This installation was available over most hours in 2019.

A third solar facility is under development near Troy, IN and will have an installed capacity near 50 MW. It is expected to be operational in early 2021.

6.2.4 Energy Efficiency

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

Since 1992, Vectren has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads 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. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete. Between 2010 and 2018, Vectren's DSM programs reduced demand by approximately 69,000 kW and provided annual incremental gross energy savings of approximately 360,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since Vectren 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 6.8 Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.53	.00051	0.04%
2011	5,594.84	19.40	.00331	0.35%
2012	5,464.75	66.95	.01212	1.23%
2013	5,459.11	128.64	.02271	2.36%

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2014**	3,498.69	175.98	.03053	5.03%
2015	3,223.81	202.82	.03552	6.29%
2016	3,256.3	236.40	.04336	7.26%
2017	3,280.7	268.86	.05005	8.20%
2018	3,490.7	309.28	.05759	8.86%

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

**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.

6.2.4.1 2018-2020 Plan Overview

Consistent with the 2016 IRP, the framework for the 2018-2020 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2018-2020. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2018-2020 EE Plan detail found in the Technical Appendix Attachment 6.2 Vectren Electric 2018-2020 DSM Plan.

Residential Programs

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Prescriptive
- Residential New Construction
- Residential Behavior Savings
- Residential Smart Thermostat Demand Response (Incentives only)
- Bring Your Own Thermostat (BYOT)

- Food Bank – LED Bulb Distribution
- Conservation Voltage Reduction (CVR) Residential

Commercial & Industrial Programs

- Small Business Direct Install
- Commercial & Industrial Prescriptive
- Commercial & Industrial New Construction
- Commercial & Industrial Custom
- Building Tune-Up
- Multi-Family Retrofit
- Conservation Voltage Reduction - Commercial

The 2018-2020 plan was included an existing resource in the 2019/2020 IRP and has an assumed average measure life of 12 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 6.2 Vectren Electric 2018-2020 DSM Plan).

Figure 6.9 2018-2020 Energy Efficiency Savings

	2018*		2019**		2020***	
Sector	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings
Residential	19,241	4.0	19,129	4.0	15,821	4.7
Commercial & Industrial	21,602	3.2	16,495	3.4	16,208	1.7
Total	40,843	8.5	35,624	7.4	32,029	6.4

* 2018 Evaluation Results used for 2018
** 2019 Operating Plan used for 2019 savings and Net to Gross (NTG) Factors
*** 2018-2020 Filed Plan used for 2020 Savings and NTG Factors

6.2.5 Demand Response

Vectren's tariff currently includes two active demand response programs: 1) the Direct Load Control and 2) interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also

includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time.

6.2.5.1 Current DLC (Summer Cycler)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps through radio-controlled load management receivers. Under the program, Vectren compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren 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.

Vectren 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. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2020 Cadmus predicted that the DLC Program was capable of generating approximately 8.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. This is roughly half of prior predictions, which were used for IRP modeling.

Until recently, DLC switches have been the default choice for residential load control programs. Vectren has had a DLC program since the early 1990's and as of 2019 had approximately 21,000 residential customers with 27,000 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they

offer for both EE and DR, Vectren plans to begin replacing DLC switches with smart thermostats.

6.2.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. Vectren included three customers who were participating for a total demand reduction of 35 MW. New MISO testing requirements are currently being put into place to ensure these DR resources are available throughout the year. MISO is proposing interruptible resource accreditation based on the amount of interruptions and available hours to curtail. MISO has already implemented mandatory annual testing for the first time that will require load interruptions to meet the test requirements. Prior to January 31, 2019, Vectren had never been requested by MISO to deploy LMRs, thereby interrupting customer load. Because of these changes that will now require annual interruptions that are likely to increase in occurrence and duration, Vectren expects some, if not all, of its currently enrolled customers to drop out, as frequent interruptions in service can be very costly to industrial customers' operations. Since implemented, one customer (~7MWs) has left the program. While aggressive, Vectren maintained industrial interruptible load at the 35 MWs within the model throughout the analysis period. Given Vectren's mix of industrial customers, it is unlikely that new customers will sign up for this program. As such, Vectren did not allow the model to select additional interruptible DR.

6.2.5.3 Smart Thermostats

Vectren 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. Preliminary evaluation results are showing significantly more load reduction delivered by smart thermostats. The current DLC switch program is a well-established means for Vectren to shed load during

peak demand; however, over time, this option is will become obsolete. As such, Vectren has designed a program to change out from switches to smart Wi-Fi thermostats, a strategic option for cost effective load control. The Smart DLC Change-out program will focus on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, Vectren 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.

Additionally, Vectren also launched the Bring your Own Thermostat (BYOT) program as a demand response program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2018-2020 Plan provides for 240kW demand each year from the BYOT program based on 400 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in DR and other load curtailing programs managed through the utility. 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 0.6 kW - 1 kW per thermostat in load reductions during a DR event.

6.3 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

Vectren utilized the All-Source RFP for modeling inputs through 2024 for wind, solar, solar + storage resources, (Tier 1 bids) as shown in Figure 6.5. The following supply side information was based on a technology assessment from Burns and McDonnell unless otherwise noted and was used to help provide needed information to model other

resources where Vectren did not receive a Tier 1 bid and for resources in future years and utilizing the cost curve information in Figure 6.21.

6.3.1 Supply Side

Resources are typically divided into supply side and demand side resources. Supply side simply means resources that produce energy.

6.3.1.1 Coal Technologies

Coal power plants, also known as Pulverized Coal (PC) steam generators, are characterized by pulverizing coal, then burning the coal in a boiler to create heat. The heat from the boiler is then used to turn water into high pressure steam which is used to turn the turbine causing the generator to create electricity.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3208 psia and 705°F, supercritical units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

Proposed greenhouse gas (GHG) regulations for new construction will limit CO_2 emissions to 1,100 lbs./MWh, a level which would require carbon capture on PC plants. Carbon capture on PC plants has been demonstrated in the field and as the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. See Figure 6-10 for further details on the coal technologies evaluated.

Figure 6-10 – Coal Technologies

Coal		
Operating Characteristics and Estimated Costs	**Supercritical Pulverized Coal with Carbon Capture**	**Ultra-Supercritical Pulverized Coal with Carbon Capture**
Base Load Net Output (MW)	506	747
Base Load Net Heat Rate (HHV Btu/kWh)	11,290	10,480
Base Project Costs (2019$/kW)	$6,370	$5,760
Fixed O&M Costs (2019$/kW-year)	$29.10	$29.10

6.3.1.2 Natural Gas Technologies

6.3.1.2.1 Simple Cycle Gas Turbines (Combustion Turbines or CT)

SCGT 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 6-11 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. Estimates were developed for firm gas supply (as opposed to interruptible) because MISO has signaled that while summer peak hours are important all hours of the year matter and a dispatchable resource needs to be available for service when needed by the system. The A.B. Brown site was used for this analysis. It is an existing brownfield site with interconnection rights through MISO. The cost estimates were developed in partnership with a potential service provider, Texas Gas.

Figure 6-11 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines					
Operating Characteristics and Estimated Costs	**1xLM 6000 SCGT**	**1xLMS 100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**	**1xG/H-Class SCGT**
Base Load Net Output (MW)	41.6	97.2	84.7	236.6	279.3
Base Load Net Heat Rate (HHV Btu/kWh)	9,280	8,895	11,527	9,928	9,311
Base Project Costs (2019$/kW)	$2,230	$1,660	$1,470	$730	$810
Fixed O&M Costs (2019$/kW-year)[27]	$36.28	$16.04	$21.46	$8.32	$8.02

6.3.1.2.2 Combined Cycle Gas Turbines

Combined Cycle Gas Turbines (CCGT) 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 Heat Recovery Steam Generator (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 Heat Recovery Steam Generator (HRSG) to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, a 1x1 F class and G/H class, as shown in Figure 6-12, were evaluated with General Electric (GE) turbines as representative CCGT technologies. The F class is based on the GE 7F.05 turbine and the G/H class is based on the GE HA.01 turbine. A 1x1 CCGT is configured with one gas turbine and one steam turbine. Vectren did not model a large 2x1 CCGT. See Figure 6-12 for further details on the CCGT technologies evaluated.

[27] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs

Figure 6-12 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines		
Operating Characteristics and Estimated Costs[28]	**1x1 7F.05 CCGT (ABB)**	**1x1 7HA.01 CCGT (ABB)**
Duct-Firing	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	365	420
Incremental Duct-Fired (Peaking) Net Output (MW)	72	79
Base Load Net Heat Rate (HHV Btu/kWh)	6,460	6,247
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,269	8,221
Base Project Costs (2019$/Fired kW)	$1,153	$1,087
Fixed O&M Costs (2019$/Base Load kW-year)[29]	$13.99	$15.94

6.3.1.3 Renewables Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, hydroelectric and waste-to-energy.

6.3.1.3.1 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 6-13 for further details on the variety of wind technologies evaluated. Beyond the RFP bids, the following assumptions were based on the Burns and McDonnell tech assessment.

[28] Combined cycle gas turbines are shown as fired configuration at A.B. Brown site for this table. Reference the Technology Assessment for additional details on duct-firing
Operational and cost estimates developed by Black & Veatch
[29] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs

Figure 6-13 – Wind Renewables

Operating Characteristics and Estimated Costs[30]	Wind (Southern Indiana)	Wind (Northern Indiana)	50 MW Wind (Indiana) & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	200	200	50
Base Project Costs (2019$/kW) / ($/kWh for Storage)	$1,450	$1,450	$1,800 / $650
Fixed O&M Costs (2019$/kW-year)	$40.00	$40.00	$44.14
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Annual Capacity Factor	28%	38%	

The Production Tax Credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 2.2% past 2019 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 60 percent for wind facilities commencing construction in 2019. See Figure 6-14 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date. Modeling assumed a safe harbor assumption of two years PTC extension for generic wind builds.

[30] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

Figure 6-14 –Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%
2021	60%*
2022	0%
2023	0%

*PTC Extended

6.3.1.3.2 Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a 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 photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

Photovoltaic (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 6-15 for further details on the solar PV technologies evaluated.

Figure 6-15 – Solar Photovoltaic

Operating Characteristics and Estimated Costs[31]	10 MW Solar PV	50 MW Solar PV	100 MW Solar PV	50 MW Solar PV & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	10	50	100	50
Base Project Costs (2019$/kW)	$1,961	$1,526	$1,414	$1,860
Fixed O&M Costs (2019$/kW-year)	$23.41	$22.91	$18.82	$22.33
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	Included in FOM	$5.74 (Storage MWh Only)

The Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible solar generation. ITC percentage depends on the commencement of construction as shown below in Figure 6-16. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The ITC was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 6-16 – Investment Tax Credit by Year

Commence Construction (Prior to)	Investment Tax Credit (%)
2017	30%
2018	30%
2019	30%
2020	30%
2021	26%
2022	22%
1/1/2022 & beyond	10%

[31] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

For the purposes of the IRP, all modeled bids received safe harbor for full realization of the ITC. Modeling assumed a safe harbor assumption of two years ITC extension for generic solar builds.

6.3.1.3.2.1 Safe Harboring Methods

There are two options, often referred to as safe harboring methods, that developers can utilize to extend qualifications for the ITC and PTC. First, a project can prove that they have started and maintained construction of the project. Second, a project can purchase five percent of the total project cost. Once these safe harboring methods are initiated the developer has 4 years to complete the project. This allows developers to prolong the usefulness of the ITC and PTC.

6.3.1.3.3 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 6-17 for further details on the hydroelectric technology evaluated.

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 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 that the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 6-17 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2019$/kW)	$6,050
Fixed O&M Costs (2019$/kW-year)	$92.40

6.3.1.3.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator to produce electricity. It should be noted that these types of projects are very site specific and hard to have generic assumptions for use in an IRP. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 6-18.

Figure 6-18 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Bubbling Fluidized Bed	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,000	10,740
Base Project Costs (2019$/kW)	$5,640	$4,110
Fixed O&M Costs (2019$/kW-year)	$124.00	$111.78

6.3.1.3.5 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered resources and are the most difficult to estimate. Congestion charges are calculated by taking the difference in Locational Marginal Pricing (LMP's) where the energy is injected (source) and where the energy is withdrawn (sink). For Vectren to purchase energy outside of Zone 6 (Indiana) or even off Vectren's system in Indiana, Vectren would be responsible to pay the LMP at the sink and would receive

payment from the source. Therefore, any price differential is an added risk and possible added cost to the delivery of energy. MISO does not provide estimates of congestion charges due to the volatility and immense variability that impacts the MISO transmission system and the congestion related charges. When taking into consideration the cost of a resource, the required transmission charges and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

Vectren's modeling accounted for congestion. As previously described, Vectren modeled tier 1 bid information, which included a "delivered price" (all in price from the developer), or projects on Vectren's system, which minimizes congestion risk. Outside of bid information, projects were generally assumed to be on Vectren's system. Any resource that is outside of Vectren's system must include an evaluation of potential congestion charges.

6.3.1.4 Energy Storage

Two types of energy storage technologies were evaluated in the IRP –lithium-ion batteries (typically short-duration) and flow batteries (long-duration). These are shown in Figure 6-19.

Batteries utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity and ease of installation and operation.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge and cycling tolerance.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

Both Li-ion and flow batteries offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours (wholesale energy market arbitrage). These storage technologies can also function as transmission assets that can assist in maintaining the reliability of the grid, potentially displacing or deferring the need for more traditional transmission upgrades.

Figure 6-19 – Energy Storage Technologies

Operating Characteristics and Estimated Costs[32]	Lithium Ion 10 MW / 40 MWh	Lithium Ion 50 MW / 200 MWh	Flow Battery 10 MW / 60 MWh	Flow Battery 10 MW / 80 MWh	Flow Battery 50 MW / 300 MWh	Flow Battery 50 MW / 400 MWh
Base Load Net Output (MW)	10	50	10	10	50	50
Round-Trip Cycle Efficiency	85%	85%	68%	68%	68%	68%
Base Project Costs (2019$/kW)	$1,972	$1,562	$3,823	$4,305	$3,034	$3,478
Fixed O&M Costs (2019$/kW-year)	$22.36	$18.85	$110.10	$110.10	$35.06	$35.06
Variable O&M Costs (2019$/MWh)	$6.07	$6.07	$1.50	$1.50	$1.50	$1.50

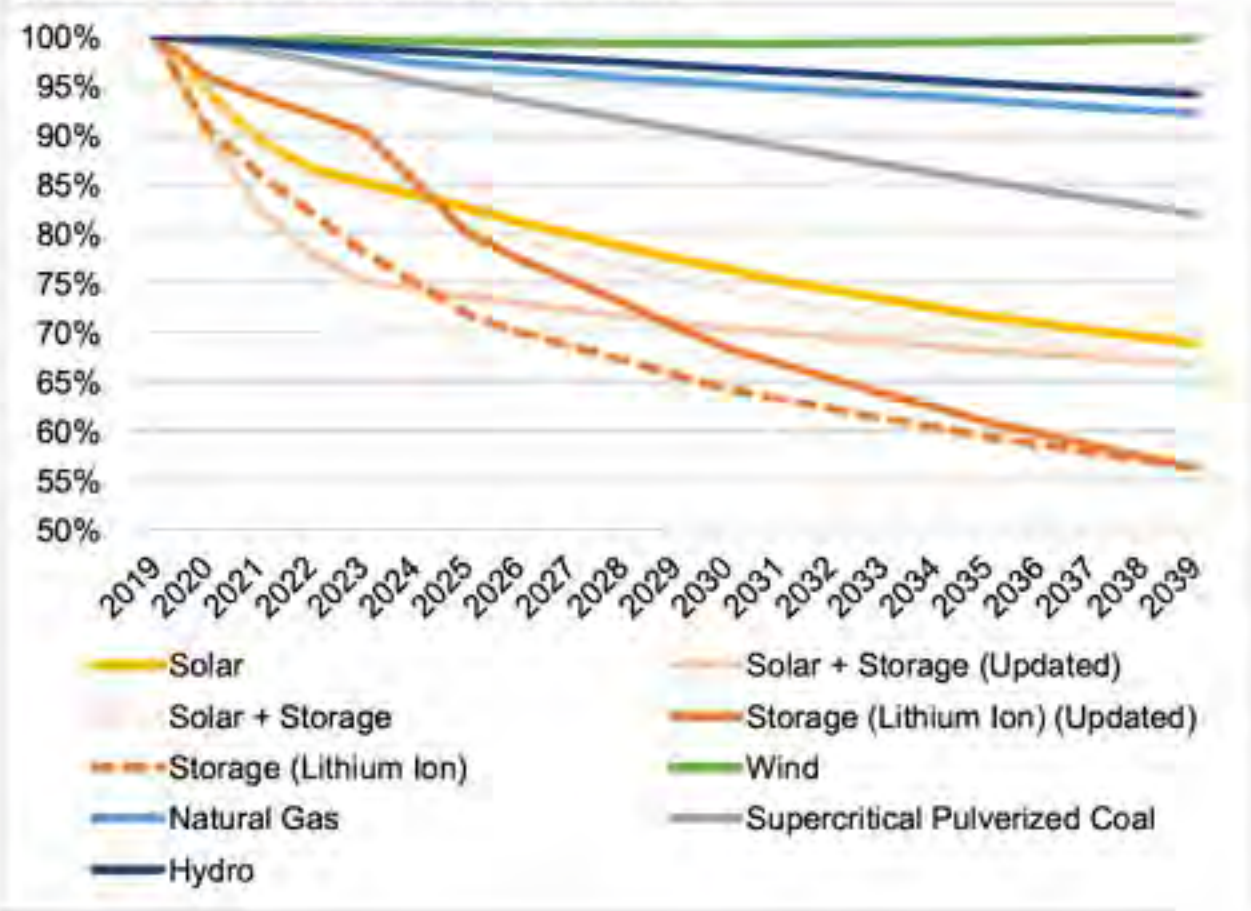
[32] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

6.3.1.5 Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2019/2020 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 6-21.

Technologies whose capital costs do not decline significantly over the IRP time period such as wind, natural gas, coal and hydro are generally more mature, while technologies such as solar and storage are less mature and are expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies in solar and storage are expected to decrease capital costs by ~30% and ~40%, respectively. Due to uncertainty associated with these less mature technologies, Vectren relied upon multiple third-party sources to develop consensus capital cost forecasts. The capital cost forecast curves were adjusted for solar + storage and storage based on data received as part of the RFP process. Solar bids received in the RFP aligned very closely with the original consensus cost curve forecast (these curves are on top of each other in Figure 6-21, solar + storage bids resulted in lowering the near-term forecast, while the bids received for standalone storage resulted in a slight increase to the near term cost curve forecast. These updates help to align Vectren's forecasts with real market data for these less mature technologies. Figures 7.12-7.14 show modeled values by scenario.

Figure 6-20 - Forward Capital Cost Estimates



6.3.2 DSM

6.3.2.1 Energy Efficiency Background

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 demand side (DSM) options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service

requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

In addition, this process aligns with Senate Enrolled Act (SEA) 412 which requires that 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.

6.3.2.2 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, decisionmakers 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."[33] 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.

[33] "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

Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: society as a whole, all ratepayers, the program administrator, program participants and utility rates.

Vectren's MPS completed in 2019 was both to inform the IRP and support the development of a DSM Action Plan for Vectren. The study included primary market research and a comprehensive review of current program, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study collected primary market research on up-to-date C&I data for the Vectren service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. Primary market research was also conducted to understand 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 that 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 that 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 that 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:

1) **Maximum Achievable Potential** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
2) **Realistic Achievable Potential** estimates achievable potential with Vectren 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 that the estimates of technical, economic and achievable 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 Vectren's energy efficiency programs. In the Vectren service area, approximately 75% of large C&I customers are eligible to opt-out and nearly 40% of eligible customers have chosen to do so. As a result, only 22% of total large C&I energy (MWh) sales have not presently opted out of funding Vectren's energy efficiency programs.[34]

6.3.2.3 Energy Efficiency – IRP Reference Case

For the DSM reference case of the IRP analysis, Vectren used the realistic achievable potential identified in the 2019 Market Potential Study as the starting point for developing bundles of energy efficiency to be modeled in .25% increments of eligible sales. However, two additional adjustments to the MPS' realistic achievable energy efficiency potential were necessary prior to inclusion in the IRP.

[34] These percentages are calculated based on 2019 Vectren large C&I customer data and 2018-2019 billing history.

The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts in order to remove MWh and MW impacts that would have occurred even in the absence of Vectren's programs. Net savings were calculated by applying Vectren's most recent (2017) program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings. Due to annual differences in the mix of energy efficiency measures included in the realistic achievable potential, the weighted average NTG ratio adjustment ranged from 0.84 to 0.88 across the 20-year IRP analysis timeframe.

The second adjustment aligned the level of low-income potential identified in the realistic achievable potential with levels achieved historically by Vectren. The MPS assumes Vectren pays the full cost for all possible low-income potential savings, regardless of cost-effectiveness. However, this produces a low-income budget that significantly outpaces historical spending for the low-income sector and would create cross-subsidization concerns across customer segments. As a result of aligning the low-income sector spending in the IRP with recent historical levels, low-income achievable savings were also scaled accordingly.

The model included 2020 savings as a fixed resource as savings are currently approved by the Commission in Cause 44927. A total of 10 bundles were modeled for DSM, including one fixed low-income bundle, one fixed DR bundle (AC DLC as well as Smart Thermostat), one selectable DR BYOT (Bring Your Own Thermostat) and seven selectable energy efficiency bundles each representing 0.25% of annual load excluding opt-out sales.

Figure 6-22 shows the realistic achievable potential (as a % of annual forecast sales) identified in the MPS and the impacts after applying the two adjustments described above.

Figure 6-21 – MPS Realistic Achievable Potential (as a % of annual eligible sales) – Pre- & Post-Adjustments

	2020	2021	2022	2023	2024	2025
MPS Realistic Achievable	1.7%	2.1%	2.0%	2.0%	2.0%	2.0%
Adj#1: Gross to Net	1.4%	1.8%	1.7%	1.8%	1.8%	1.7%
Adj#2: Low Income Alignment	1.2%	1.5%	1.4%	1.5%	1.5%	1.5%

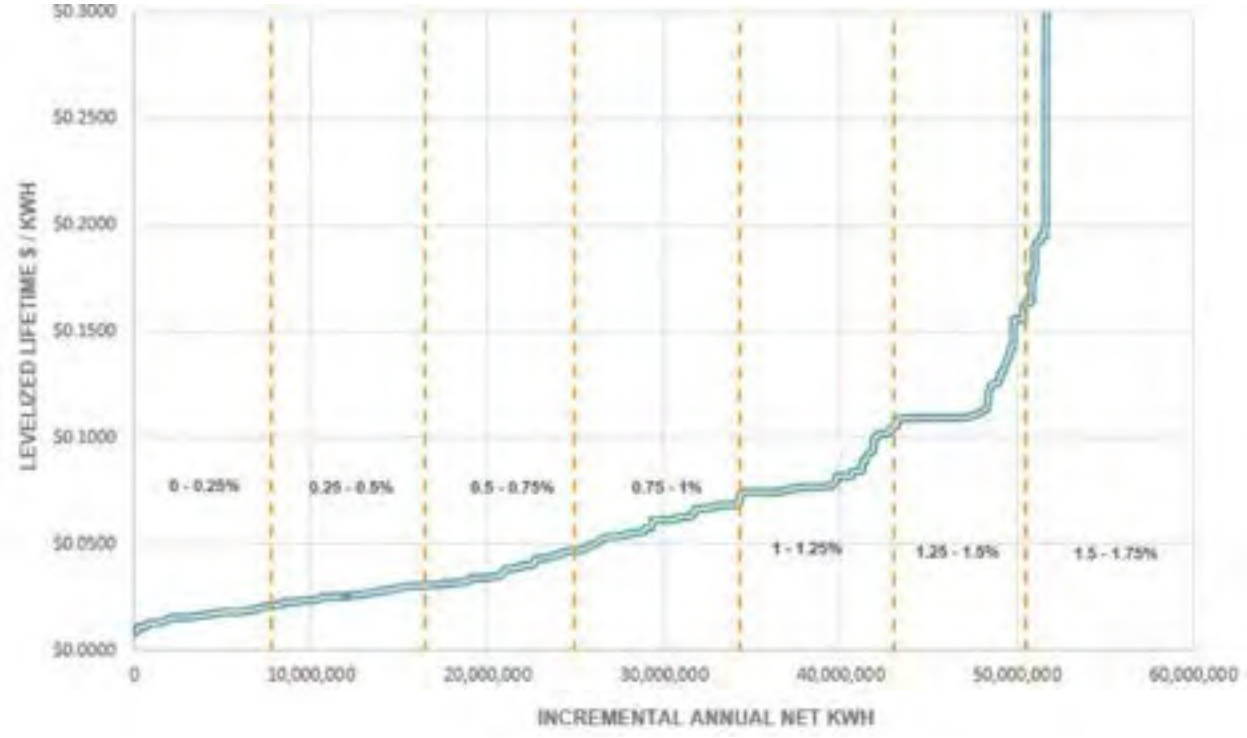
For the Vectren IRP process, energy efficiency is a selectable resource. Once the total energy efficiency savings to be included in the IRP Reference Case were calculated, a cost was assigned to each bundle of energy efficiency so that it can compete and be selected against supply-side resources. Again, the 2019 MPS and the annual supply curves were used to develop costs for each energy efficiency bundle. The costs from the MPS include incentive costs, program delivery costs and other cross-cutting program costs based on reported historical levels. Two modifications to the MPS cost estimates were created to further align the IRP Reference Case with empirical Vectren data. The first adjustment was to reduce incentive costs in the C&I sector from 2020 through 2027. This adjustment served to align modeled costs with Vectren recent historical and 2019 planned costs in the C&I sector. The second adjustment was to change the escalation rate for non-incentive program costs to 2.2% (in lieu of the 1.6% modeled in the MPS) to be consistent with other IRP planning assumptions.[35]

Following these savings and costs adjustments, a supply curve of the remaining electric energy efficiency potential was developed for each year of the MPS. A supply curve of energy efficiency potential is a device for demonstrating the total amount of energy efficiency savings available at specific price points, with the x-axis representing the cumulative annual energy savings available and the y-axis representing the cost of saved energy. The energy efficiency supply curve is useful in that it creates a logical order for pursuing energy efficiency measures based on least cost planning. Energy efficiency measures along the supply curve were then bundled into blocks of approximately 0.25%

[35] Incentive costs were not escalated in the MPS or IRP DSM inputs. Incentives (as a % of measure costs) were held constant in nominal dollars. Any fluctuation in incentives is a result of changes in annual participation.

net energy savings relative to forecast sales. The total number of energy efficiency bundles, each year, is dependent on the realistic achievable potential identified in that year. For example, the realistic achievable potential identified in 2024 allows for 6 complete bundles of 0.25% net efficiency savings and a partial 7th bundle (Figure 6-23).

Figure 6-22 – 2024 Supply Curve for Electric Energy Efficiency



As a final step in the IRP Reference Case energy efficiency bundle development, a single low-income bundle of energy efficiency was created. As noted earlier, this savings bundle is aligned so that total low-income spending in 2020-2039 is consistent with recent historical levels ($1.15 million annually). The cost per lifetime kWh-saved is expected to change over time as the associated mix of low-income measures in the realistic achievable potential changes. Annual savings associated with the LI Bundle range from 889 MWh in the early years of the IRP to a low of 457 MWh as the measure mix converts to higher $/kWh measures over time.

The following table (Figure 6-24) provides the estimated levelized costs, on a cumulative basis, used for each of the energy efficiency bundles included in the IRP Reference Case.

Except for the low-income bundle, no minimum level of energy efficiency impacts was locked in for the IRP optimization modeling for scenario analysis. Empty cells reflect a lack of net achievable potential (based on the MPS results) in that year.

Figure 6-23 – IRP Reference Case Cost of Energy Efficiency; Cost per Net Lifetime kWh[36]

CUM. BIN NET $/kWh	1	2	3	4	5	6	7	LI
2020	$ 0.0163	$ 0.0204	$ 0.0240	$ 0.0299	$ 0.0369			$ 0.1241
2021	$ 0.0154	$ 0.0201	$ 0.0232	$ 0.0268	$ 0.0314	$ 0.0380		$ 0.1448
2022	$ 0.0154	$ 0.0202	$ 0.0245	$ 0.0289	$ 0.0326	$ 0.0394		$ 0.1594
2023	$ 0.0158	$ 0.0206	$ 0.0246	$ 0.0292	$ 0.0342	$ 0.0397		$ 0.1754
2024	$ 0.0162	$ 0.0204	$ 0.0247	$ 0.0302	$ 0.0355	$ 0.0377	$ 0.0412	$ 0.1997
2025	$ 0.0168	$ 0.0217	$ 0.0263	$ 0.0321	$ 0.0375	$ 0.0410	$ 0.0427	$ 0.2134
2026	$ 0.0172	$ 0.0226	$ 0.0278	$ 0.0336	$ 0.0391	$ 0.0426	$ 0.0446	$ 0.2255
2027	$ 0.0179	$ 0.0237	$ 0.0291	$ 0.0357	$ 0.0409	$ 0.0442	$ 0.0462	$ 0.2429
2028	$ 0.0185	$ 0.0250	$ 0.0311	$ 0.0372	$ 0.0426	$ 0.0468	$ 0.0485	$ 0.2469
2029	$ 0.0194	$ 0.0262	$ 0.0330	$ 0.0399	$ 0.0443	$ 0.0499		$ 0.2481
2030	$ 0.0202	$ 0.0283	$ 0.0342	$ 0.0402	$ 0.0457	$ 0.0521		$ 0.2453
2031	$ 0.0210	$ 0.0294	$ 0.0350	$ 0.0423	$ 0.0470	$ 0.0531		$ 0.2517
2032	$ 0.0220	$ 0.0304	$ 0.0366	$ 0.0443	$ 0.0491	$ 0.0557		$ 0.2299
2033	$ 0.0233	$ 0.0317	$ 0.0409	$ 0.0478	$ 0.0505	$ 0.0574		$ 0.2345
2034	$ 0.0241	$ 0.0328	$ 0.0432	$ 0.0497	$ 0.0525	$ 0.0596		$ 0.2038
2035	$ 0.0203	$ 0.0262	$ 0.0323	$ 0.0405	$ 0.0462	$ 0.0480	$ 0.0545	$ 0.2285
2036	$ 0.0206	$ 0.0262	$ 0.0320	$ 0.0405	$ 0.0456	$ 0.0482	$ 0.0547	$ 0.2413
2037	$ 0.0208	$ 0.0264	$ 0.0322	$ 0.0399	$ 0.0457	$ 0.0485	$ 0.0547	$ 0.1969
2038	$ 0.0218	$ 0.0256	$ 0.0324	$ 0.0395	$ 0.0450	$ 0.0498	$ 0.0558	$ 0.2006
2039	$ 0.0231	$ 0.0262	$ 0.0333	$ 0.0398	$ 0.0458	$ 0.0506	$ 0.0564	$ 0.2068

6.3.2.4 Demand Response

Two bundles for demand response savings were included in the IRP Reference Case. The first bundle was included as a fixed adjustment to the total system load, similar to a "must-run" generation unit. This bundle includes demand response savings associated with Vectren's current demand response capabilities including the historical number of

[36] Savings bundles were based on net savings that were roughly equivalent to 0.25% of annual sales. Projected costs per kWh for each bundle are shown at the gross-level for easier comparison to prior IRP. Projected costs by bundle are cumulative (i.e. the projected cost in Bundle 4 represent the cost to achieve up to 1.0% of forecast sales).

direct load control switches on residential air conditioning units in the Vectren service area. Over the IRP time frame, Vectren anticipates replacing existing direct load control switches with smart thermostats that integrate demand response capabilities (via the Smart Cycle Program). The estimated annual impacts for the fixed bundle of DR is approximately 16 MW in 2020, increasing to 26 MW by 2039.

A second bundle, consisting of additional demand response enabled smart thermostats (BYOT Thermostats) above and beyond the current penetration of demand response devices, was included as a selectable resource. This bundle represents an additional 1.6 MW of peak reduction capabilities in 2020 increasing to 10 MW by 2039.

6.3.2.5 DSM Resources – IRP Sensitivities

The previous sections provided the Reference Case projection of DSM resource costs. DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20-year implementation period, alternate views of the costs should be examined in the context of the scenario analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections.

To that end, high and low DSM resource cost trajectories were developed by leveraging Vectren's 2011-2018 historical DSM spend per first-year kWh saved and calculating one standard deviation from the mean to develop high and low DSM spend scenarios. This approach uses the actual variation in Vectren's energy efficiency resource acquisition costs to define upper and lower bounds on future DSM costs per first-year kWh-saved. The result is an 11.9% increase or reduction in estimated annual DSM costs relative to the IRP Reference Case. Figure 6-25 shows the 2011-2018 average cost per first-year kWh-saved used to determine the IRP sensitivities on DSM costs.

Figure 6-24 – 2011-2018 Vectren Portfolio Cost per 1st-Year kWh Saved



Applying a range of expected costs produces the following high and low tables of projected DSM resource costs.

Figure 6-25 – High Case Cost per kWh: Plus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0182	$ 0.0229	$ 0.0269	$ 0.0335	$ 0.0413		
2021	$ 0.0173	$ 0.0225	$ 0.0259	$ 0.0300	$ 0.0351	$ 0.0428	
2022	$ 0.0172	$ 0.0226	$ 0.0274	$ 0.0323	$ 0.0365	$ 0.0440	
2023	$ 0.0177	$ 0.0230	$ 0.0275	$ 0.0326	$ 0.0383	$ 0.0444	
2024	$ 0.0181	$ 0.0229	$ 0.0277	$ 0.0338	$ 0.0397	$ 0.0421	$ 0.0461
2025	$ 0.0188	$ 0.0242	$ 0.0294	$ 0.0359	$ 0.0419	$ 0.0458	$ 0.0478
2026	$ 0.0192	$ 0.0253	$ 0.0311	$ 0.0376	$ 0.0437	$ 0.0476	$ 0.0499
2027	$ 0.0200	$ 0.0265	$ 0.0325	$ 0.0399	$ 0.0457	$ 0.0495	$ 0.0517
2028	$ 0.0207	$ 0.0280	$ 0.0348	$ 0.0416	$ 0.0477	$ 0.0524	$ 0.0543
2029	$ 0.0217	$ 0.0293	$ 0.0369	$ 0.0446	$ 0.0496	$ 0.0559	
2030	$ 0.0226	$ 0.0317	$ 0.0382	$ 0.0450	$ 0.0511	$ 0.0582	
2031	$ 0.0235	$ 0.0329	$ 0.0391	$ 0.0473	$ 0.0526	$ 0.0594	
2032	$ 0.0246	$ 0.0341	$ 0.0434	$ 0.0496	$ 0.0550	$ 0.0624	
2033	$ 0.0260	$ 0.0355	$ 0.0458	$ 0.0535	$ 0.0585	$ 0.0642	
2034	$ 0.0269	$ 0.0367	$ 0.0483	$ 0.0556	$ 0.0587	$ 0.0667	
2035	$ 0.0227	$ 0.0293	$ 0.0361	$ 0.0453	$ 0.0517	$ 0.0537	$ 0.0610
2036	$ 0.0231	$ 0.0293	$ 0.0358	$ 0.0453	$ 0.0511	$ 0.0539	$ 0.0612

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2037	$ 0.0233	$ 0.0295	$ 0.0360	$ 0.0446	$ 0.0511	$ 0.0543	$ 0.0612
2038	$ 0.0244	$ 0.0287	$ 0.0363	$ 0.0442	$ 0.0503	$ 0.0558	$ 0.0624
2039	$ 0.0258	$ 0.0293	$ 0.0373	$ 0.0445	$ 0.0513	$ 0.0567	$ 0.0631

Figure 6-26 – Low Case Cost per kWh: Minus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0143	$ 0.0180	$ 0.0212	$ 0.0264	$ 0.0325		
2021	$ 0.0136	$ 0.0177	$ 0.0204	$ 0.0236	$ 0.0276	$ 0.0335	
2022	$ 0.0135	$ 0.0176	$ 0.0216	$ 0.0254	$ 0.0287	$ 0.0347	
2023	$ 0.0139	$ 0.0181	$ 0.0216	$ 0.0257	$ 0.0302	$ 0.0350	
2024	$ 0.0143	$ 0.0180	$ 0.0218	$ 0.0266	$ 0.0313	$ 0.0332	$ 0.0363
2025	$ 0.0148	$ 0.0191	$ 0.0232	$ 0.0282	$ 0.0330	$ 0.0361	$ 0.0377
2026	$ 0.0151	$ 0.0199	$ 0.0245	$ 0.0296	$ 0.0344	$ 0.0375	$ 0.0393
2027	$ 0.0158	$ 0.0209	$ 0.0256	$ 0.0314	$ 0.0360	$ 0.0389	$ 0.0407
2028	$ 0.0163	$ 0.0220	$ 0.0274	$ 0.0328	$ 0.0375	$ 0.0412	$ 0.0427
2029	$ 0.0171	$ 0.0231	$ 0.0291	$ 0.0351	$ 0.0390	$ 0.0440	
2030	$ 0.0178	$ 0.0250	$ 0.0301	$ 0.0354	$ 0.0403	$ 0.0459	
2031	$ 0.0185	$ 0.0259	$ 0.0308	$ 0.0373	$ 0.0414	$ 0.0468	
2032	$ 0.0194	$ 0.0268	$ 0.0342	$ 0.0391	$ 0.0433	$ 0.0491	
2033	$ 0.0205	$ 0.0279	$ 0.0361	$ 0.0421	$ 0.0445	$ 0.0506	
2034	$ 0.0212	$ 0.0289	$ 0.0380	$ 0.0436	$ 0.0462	$ 0.0525	
2035	$ 0.0179	$ 0.0231	$ 0.0284	$ 0.0357	$ 0.0407	$ 0.0423	$ 0.0480
2036	$ 0.0181	$ 0.0231	$ 0.0282	$ 0.0356	$ 0.0402	$ 0.0425	$ 0.0482
2037	$ 0.0183	$ 0.0232	$ 0.0284	$ 0.0351	$ 0.0402	$ 0.0428	$ 0.0482
2038	$ 0.0192	$ 0.0226	$ 0.0286	$ 0.0348	$ 0.0396	$ 0.0439	$ 0.0492
2039	$ 0.0203	$ 0.0231	$ 0.0293	$ 0.0350	$ 0.0404	$ 0.0446	$ 0.0497

No IRP sensitivities for the low-income savings or demand response savings were included in the IRP as these bundles were modeled as fixed load impacts.

6.3.2.5.1 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 2016 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 2021 and 2024 and then evaluates the remaining years

beginning in 2027 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences between the short, mid and long run. Another improvement is the addition of bin specific load shapes which improved accuracy versus utilizing the same average load shape for each bin. Further, DR bundles have been added to the model. The modeled savings were aligned to the latest MPS and conducted price sensitivities mentioned in section "DSM Resources – IRP Sensitivities". The addition of price sensitivities guides Vectren's understanding of energy savings potential as costs might vary.

6.3.2.6 Other Innovative Rate Design

Vectren periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives will be considered now that the required technology upgrades are being finalized, including technology to improve access to multitudes of data provided by installation of AMI. This information was not available for the 2019/2020 IRP.

6.4 TRANSMISSION CONSIDERATIONS

6.4.1 Description of Existing Transmission System

Vectren's transmission system is comprised of 64 miles of 345 kV lines, 377 miles of 138 kV lines and 570 miles of 69 kV lines. It 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 (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, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at Vectren's Newtonville Substation.

6.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren'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 750 MWs (or approximately 65% of peak demand). Although Vectren 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

6.4.3 Transmission Facilities as a Resource

As part of this year's IRP, Vectren performed a multitude of transmission planning analysis to study a wide range of potential futures. These included studying the replacement of various levels of coal generation with a Combined Cycle Gas Turbine (CCGT), Combustion Turbines (CTs) and import from the MISO market. Each of these cases also included the addition of various levels of renewable resources, primarily solar and wind. The models utilized were from the latest cycle of the MISO generation interconnection process in order to have the latest modeling data for generation resources in Vectren's area. The renewable resources used for Vectren's analysis were projects already in the MISO queue and existing in the MISO models, while the CCGT and CT's were modeled at Vectren's A.B. Brown power plant for ease of modeling.

The CCGT case was modeled at a similar MW output as the coal generation it was replacing and therefore the results of the transmission planning study analysis showed very few differences from the study case with the system as it is today, or Base Case.

As the level of power imported from the MISO market increased due to the coal generation retirements, network upgrades were identified to increase the Vectren system import capability to suitable levels. These projects included the replacement of three transformers at an estimated total cost of $11 million and were needed for all non-CCGT cases, including the CT cases. In addition to these identified import capability issues, voltage issues also arose due to insufficient reactive power reserves as the level of imported power increased. These issues were minimal in the CT cases due to the reactive capability of the CT's and could be resolved with existing facilities, but the issues became substantial in the all renewables by 2030 portfolio and all import cases and would require additional upgrades of $20-$30 million beyond the $11 million described above. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed.

6.5 Partnering with Other Utilities

As a part of the 2019/2020 IRP process, Vectren contacted utilities in the region to discuss opportunities to partner together on generation projects to lower costs. Partnership opportunities with other Indiana utilities did not materialize due to a variety of factors including a lack of alignment in timing, needs, or other factors.

SECTION 7
MODEL INPUTS AND ASSUMPTIONS

7.1 RESOURCE MODEL (AURORA)

AURORAxmp was the primary tool for conducting Vectren's analysis. AURORAxmp is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a mixed integer linear programming approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets.

The model can be run in several modes; two were utilized for this study. The Long-Term Capacity Expansion mode (LTCE), the model was utilized to determine the least cost mix of existing and new generating assets that meets demand (electric load) over time and also meets regulatory and reliability requirements. In dispatch mode, the model was utilized to assess how a portfolio of assets will perform under a fixed set of market conditions.

AURORAxmp is widely used by electric utilities, consulting agencies and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g. heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model assesses the potential performance, fixed and variable O&M costs and capital costs of prospective and existing generation technologies and resources and makes resource addition and retirement decisions for economic, system reliability and policy compliance reasons on a utility system, regional and nationwide scale. Outputs of the model include plant generation, gross margin, emissions, power prices, capacity additions, retirements and a variety of other metrics.

Pace Global has used Aurora for well over 15 years as its primary model for asset valuation, power market forecast and IRPs. The model is equipped to determine least cost portfolios and it can analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Pace Global has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic uncertainty in key market drivers and cross relationships between different market drivers. Pace Global has also developed modules to simulate the different operating characteristics of ISO/RTO regions across the country. For this reason, it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. Pace Global has successfully conducted numerous IRPs for many utilities across the country. Aurora has gained wide acceptance among electric utility executives, stakeholder groups and regulatory commissions.

In order to perform both the required deterministic (scenario based) and probabilistic (stochastic) modeling, Pace Global developed five scenarios and a set of probability distributions for key market driver variables. These include both forecasts of each variable under the five conditions and probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon) and capital costs. In the sections below is a description of how these forecasts and distributions were developed.

7.2 REFERENCE CASE SCENARIO

Vectren developed a Reference Case forecast of key market drivers that collectively represent the expected or most likely to occur path forward for each input variable. For key assumptions, including natural gas prices, coal prices and capacity prices, a range of views from four vendors were incorporated into a consensus forecast.

The Reference Case scenario is based upon consensus forecasts from several consultants. Hence, it is impossible to describe specifics regarding the assumptions driving each forecast. However, the Reference Case can be described in more general

terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth, best guess forecasts of market conditions, regulatory requirements and technological change. Typically, market participants under Reference Case conditions can adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2020-2021), the Reference Case assumes an overall positive sales growth as Vectren adds general service and large customer growth. Residential customer annual consumption is expected to decline slightly to 2021 before rising again in the medium-term and long-term. Large commercial and industrial (C&I) customers are expected to increase both in numbers and consumption, also with a partial offset of this growth by increasing efficiency. As a result, average energy sales grow at 2.2% for 2019-2021.

Natural gas prices are expected to decline in 2020 compared to 2019, as the oversupply situation from shale gas and associated gas production continues to dominate gas market dynamics. In the short-term, natural gas prices are expected to remain below $2.80/MMBtu.

Meanwhile, coal prices decline in the near-term as domestic markets remain soft. Exports of coal provide a small amount of upward pressure demand, but mine prices are expected to continue to decline in the short-term from the 2019 price of $1.78/MMBtu in the Illinois Coal Basin.

Coal plant retirements were high in 2015 driven by regulation including MATS and again in 2018 for economic reasons. Capacity additions in the form of efficient combined cycle gas turbine plants or fast-ramping simple cycle gas turbines grew rapidly over the past few years as merchant plants and utilities took advantage of low gas prices. The EIA in

its AEO 2020 report anticipates a continued pace of capacity additions over the next few years, balanced between gas plants and renewables.[37]

Medium Term: In the medium-term (2022-2028), the Reference Case reflects the assumption that a carbon price will be implemented on the national level and will begin in 2027 at approximately $4/short ton of CO_2 (in real 2018$). CO_2 prices in California and in Northeast states participating in RGGI are expected to harmonize with the broader U.S. market at this time. In this IRP, Vectren is accounting for both direct CO_2 emissions and CO_2-equivalent (CO_2e) emissions for the life cycle of assets.

In the medium-term as in the short-term, energy efficiency standards and energy company sponsored DSM programs mostly offset the growth in energy sales from a growing residential customer base. However, overall load growth continues, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas.

Natural gas prices at the Henry Hub in the medium-term will continue to be low but will rise over time, with the consensus forecast anticipating prices in the $3.00-$3.50/MMBtu range. Low prices tend to be self-correcting, resulting in restricted production and reduced gas supply. Coupled with LNG export capacity growing through 2023 and increased industrial consumption in many parts of the country, overall demand is expected to rise and gas markets to tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, increasing prices beginning in 2021.

Coal prices in the Illinois Basin are expected to continue to decline gently in the medium-term, as the modest export market is unable to compensate for declining domestic demand. Consensus Illinois Basin prices at the mine are low, averaging $1.60/MMBtu over the study period, with a slight decline over time.

[37] https://www.eia.gov/outlooks/aeo/

Power prices, which are an output of the AURORA model for MISO Zone 6, continue to move upward moderately as natural gas prices increase from the currently low levels. As the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to improve and the unemployment rate remains near historically low levels, capital costs rise as competitive upward pressure remains on labor costs.

Coal retirements in the Reference Case mean no emissions from retired units, which contribute to lowering total CO_2 (and CO_2e) emissions. Coal plant retirements will continue to be driven by plant-specific going-forward economics, which rise as a national CO_2 price is assumed to begin in 2027. Meanwhile, capacity additions in the medium-term are expected to come from natural gas combined cycle plants as well as solar and wind facilities.

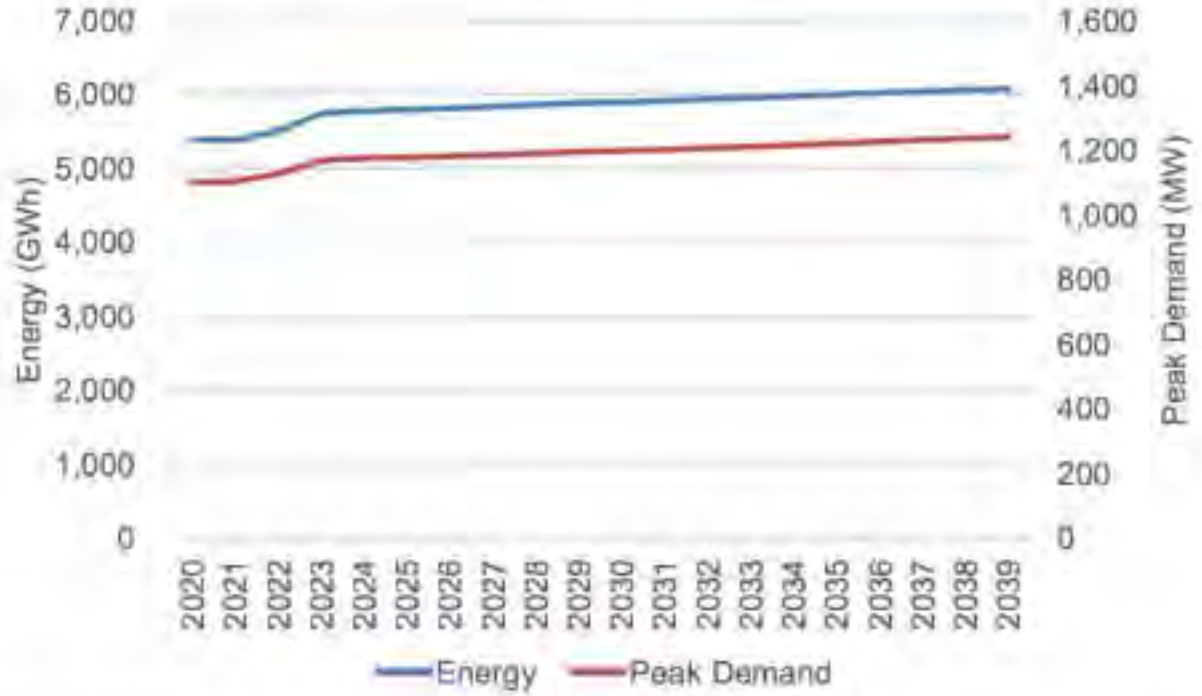
Long Term: In the long-term (2029-2039), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.6% CAGR for 2020-2039). The consensus forecast for Henry Hub has prices reaching $4/MMBtu by 2036 (in real 2018$), while ILB coal prices at the mine decline to $1.58/MMBtu by 2039 (in real 2018$). Market participants have enough time to adapt and adjust as regulatory compliance costs increase, helping to keep CO_2 prices moderate albeit rising to approximately $15/short ton by 2039 (in real 2018$). Energy demand grows as electric vehicle sales take hold and as residential and commercial customers electrify their energy use, but this is partially offset by continued gains in distributed solar generation, demand side management and energy efficiency measures. Domestic shale gas resources help to keep fuel cost growth to a low level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more and as higher borrowing costs come from long-term rising

interest rates. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

7.2.1 Input Forecasts

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron. The long-term energy and demand forecast for the MISO market comes from the System Forecasting for Energy Planning section of MISO's website.[38] For more information, please see Section 4 Customer Energy Needs. The forecast is based on a combination of historical usage trends and a bottom-up approach to drivers such as residential and commercial demand, industrial load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, electric vehicle adoption and an outlook for economic factors.

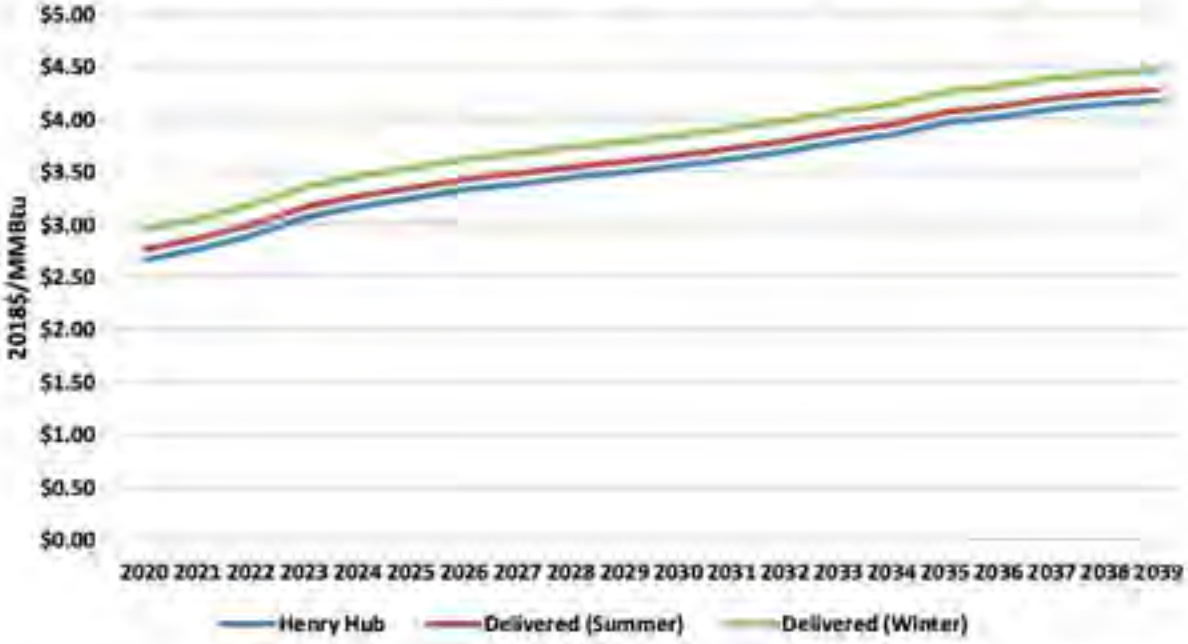
Figure 7.1 – Reference Case Vectren Load Forecast (MWh and MW)



[38] https://www.misoenergy.org/planning/policy-studies/system-forecasting-for-energy-planning/#nt=%2Freport-study-analysistype%3ALoad%20Forecast&t=10&p=0&s=FileName&sd=desc

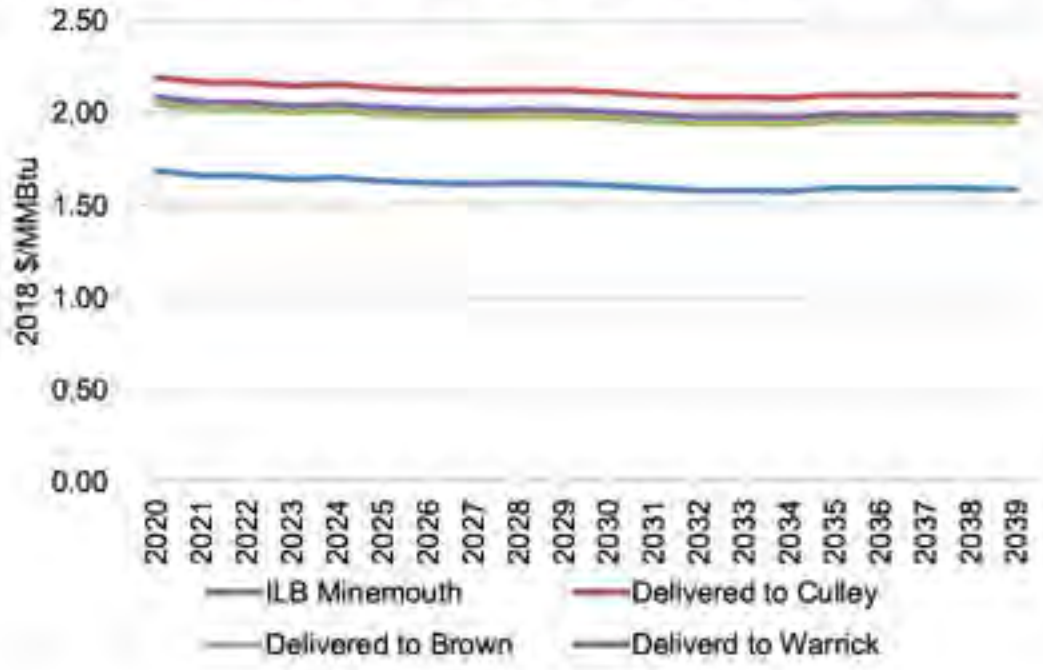
For both natural gas and coal Vectren used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. For natural gas and coal, forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, & EVA were averaged. For capacity, Vectren used a consensus forecast, using Pace Global, ABB and Wood Mackenzie[39]. This helps to capture views from several experts and allows Vectren to be more transparent in the planning process. Delivered natural gas prices are $0.10-$0.29 higher than Henry Hub due to seasonal transportation tariffs.

Figure 7.2 – Reference Case Natural Gas Price Forecast (2018$/MMBtu)



[39] Vectren did not have access to a capacity forecast from PIRA or EVA

Figure 7.3 – Reference Case Coal Price Forecast (2018$/MMBtu)

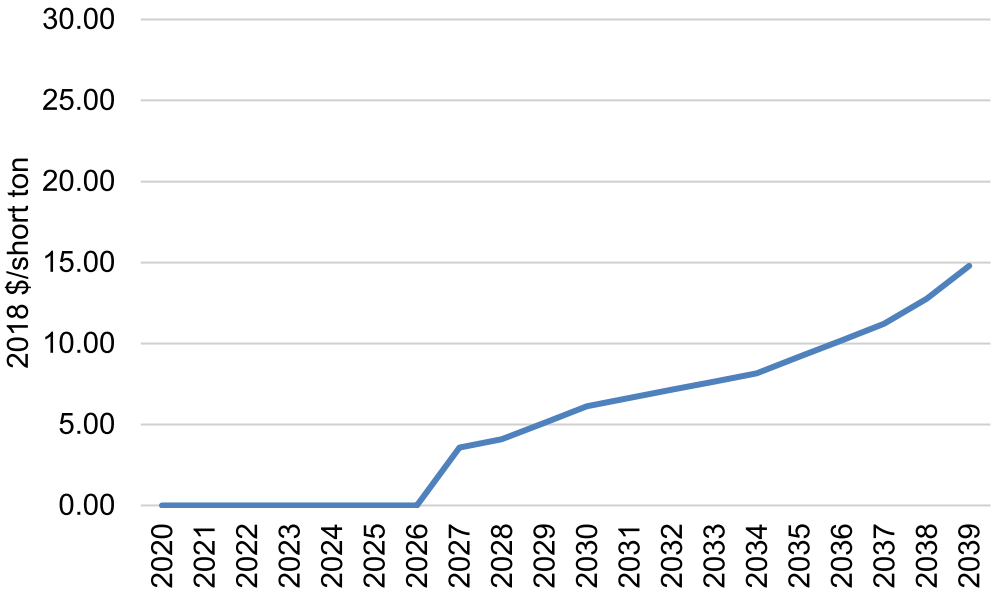


No comprehensive national legislation of carbon emissions exists in the United States currently. Efforts to enact federal policy covering carbon emissions from major sources have occurred over the years. This included efforts by the U.S. Congress to pass a national cap-and trade regime, the EPA's regulation of GHG emissions from new and existing power generators which culminated in the current ACE rule, and more recently proposals in the U.S. Congress for carbon taxes and comprehensive clean energy targets.

Action to limit carbon emissions has increased in recent years with states taking the lead in defining low and no-carbon generation requirements. Indiana does not have a state policy limiting or otherwise placing a price on carbon emissions from power generation. However, the potential remains for enactment of such a policy at the national level over the study period. To account for this uncertainty and per stakeholder request, a moderate price on CO_2 emissions from fossil generators is assumed in the Reference Case. This outlook includes a national carbon price to become effective in 2027, covering emissions

from electric generating units in the United States. Pace's EBA's CO_2 price projections in the Reference Case are presented in the figure below.

Figure 7.4 – Reference Case CO_2 Price Forecast (2018$/short ton)



Capital costs in the near to midterm (through 2024) were based on Tier 1 bids, as described in Section 6.1.5 Grouping. As described in Section 6, non-renewable capital costs were developed by Burns & McDonnell, while long term solar, wind and battery storage costs were developed using a consensus forecast from Burns & McDonnell, Pace Global and the NREL ATB 2018. Long-term capital costs for storage and solar + storage were adjusted to reflect bid pricing in the near term and then the capital cost indexes were used to adjust prices beyond the bid period. The long-term cost for solar was in line with the consensus forecast and therefore was not adjusted. Forward capital cost estimates can be found in Figure 6-21.

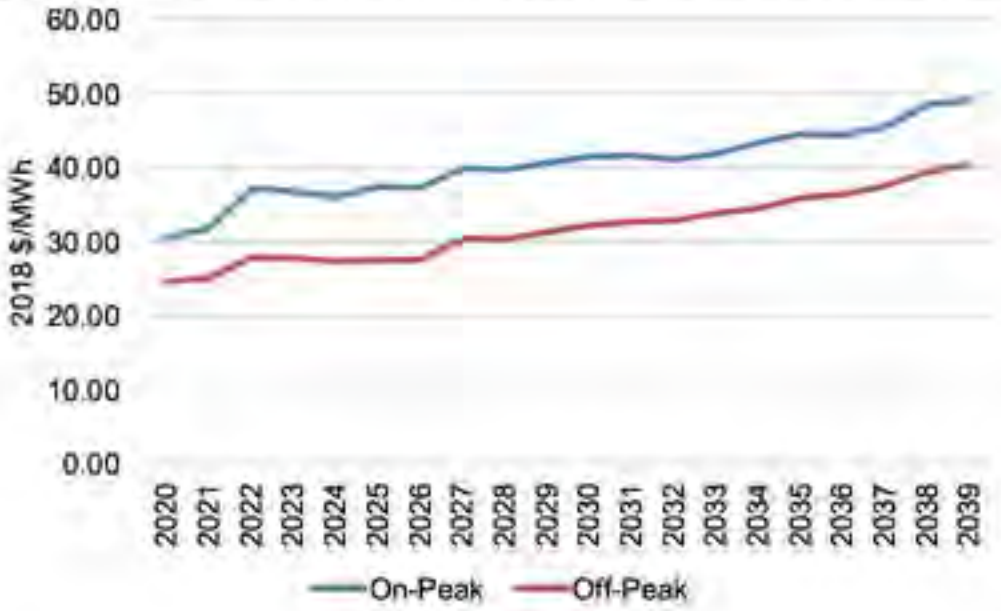
7.2.2 Energy Prices

On- and off-peak (day ahead) power price forecasts were a modeling output developed by Pace Global using the Reference Case assumptions described above, together with

Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Vectren's modeling does assume curtailment of resources when more energy is produced than is needed to meet customer load and Vectren's All-Source RFP sought operational control of resources.

Figure 7.5 – Reference Case Power Price Forecast (2018$/MWh)



Levelized DSM costs were developed by utilizing the 2019 MPS and the annual supply curves to develop costs for each energy efficiency bundle, as described in Section 6-32 Energy Efficiency Reference Case.

7.2.3 Environmental Regulations

The current modeling analysis primarily focused on evaluation of alternatives to comply with the CCR, ELG, 316(b) and ACE rule requirements. For CCR and ELG compliance, conversion to dry or closed loop bottom ash handling, wastewater treatment and landfill construction options were evaluated. For 316(b) compliance, based on site-specific

considerations, standard mesh and fish friendly screens and fish return systems were assumed. All 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 and vendor bids.

7.2.3.1 Effluent Limitations Guidelines (ELG)

A. B. Brown: ELG related changes include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash and a new system to handle process waters. ($138M)

F. B. Culley: Required plant upgrades include conversion to dry bottom ash, FGD wastewater treatment and access to a landfill that can handle dry ash. ($62M)

For Warrick Unit 4, Vectren modeled its share of the total capital spend.

7.2.3.2 Coal Combustion Residuals (CCR)

For A. B. Brown and F. B. Culley, it was assumed that ash ponds would be closed at the end of their useful life. The timing of the closures are based on forced closure (i.e. exceedance of GWPS and failure of aquifer location restriction) and whether alternative disposal capacity is available. The base cost for the closures does not change regardless of future generation. In order to continue operating coal-fired units, the A.B. Brown facility will potentially need to construct a new CCR rule compliant landfill capacity and a new CCR rule compliant pond, both of which depend on the scrubber technology utilized in the future. Vectren has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by WPP4 and therefore is not liable for pond closure costs.

7.2.3.3 Affordable Clean Energy (ACE)

As described earlier, In June 2019 EPA finalized the ACE, which replaces the Clean Power Plan from 2015 (a cap and trade program which sought to lower CO_2 emissions

from existing power plants by 30% from 2005 levels). Vectren assumed that ACE compliance would begin in 2024.

Figure 7.6 – ACE Cost

Unit	Total ACE Upgrade Cost (2019$)
A.B. Brown 1	$10 Million
A.B. Brown 2	$10 Million
F.B. Culley 2	$26 Million
F.B. Culley 3	$30 Million
Warrick 4	N\A[40]

7.2.3.4 316(b)

EPA issued its final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for cooling water intake structures (CWISs) at existing facilities.

This requirement applies to both F. B. Culley and Warrick. At this time, based on available information for A. B. Brown, IDEM has made a Best Technology Available determination that the existing cooling water intake structures represent best technology available to minimize adverse environmental impact. This determination will be reassessed at the next NPDES permit reissuance. Standard fine mesh and fish friendly screens and fish return systems were estimated to be $21M at F. B. Culley. Warrick is required to install modified travelling screens and a fish handling and return system at Warrick. Vectren is responsible for its share of total capital.

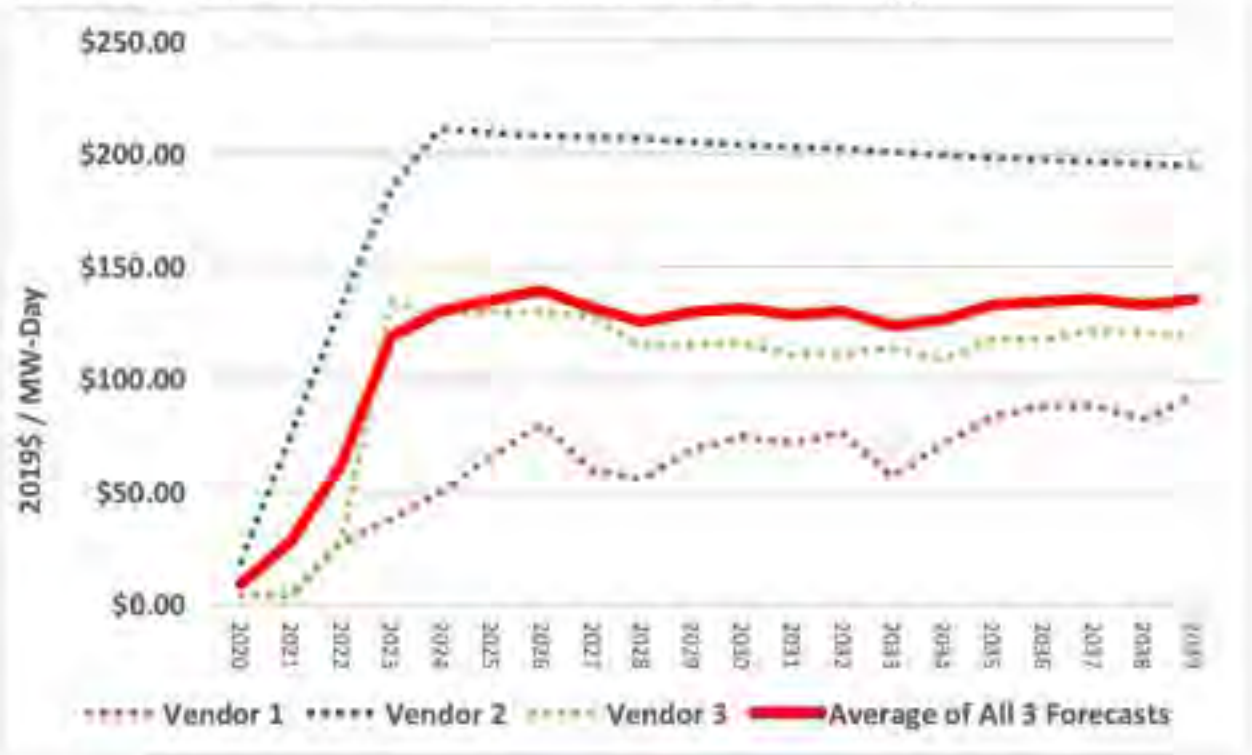
7.2.3.5 Market Capacity Price

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown. This is especially true when analyzing the clearing price for the entire MISO-region. The clearing price in neighboring zones can be drastically different than

[40] In this analysis it is assumed joint operations of Warrick 4 ends in 2023 or 2026; In the 2026 scenario there is a cost of ~$1 million

Zone 6's and becomes an important consideration as Zone 6 imports capacity to meet its planning reserve margin requirement. Nonetheless, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. For illustrative purposes only, for every $1 per MW-day increase in the auction clearing price, there is an approximate $438,000 ($1 x 1,200 MW x 365 days) annual cost of capacity impact to Vectren customers. Some capacity will be bought or sold nearly every year since load and planning reserve margin requirements vary while most supply side resources, such as generating units, come in large blocks with 30+ year expected lifetimes. Vectren used a consensus forecast, utilizing Pace Global, ABB and Wood Makenzie for Reference Case MISO Indiana capacity prices for modeling purposes.

Figure 7.7 – Capacity Market Value Forecast (2019$/MW-Day)



For reference, MISO has set the Cost of New Entry (CONE) for Zone 6 in the 2020-2021 planning year at $255/MW-Day which sets the maximum offer and clearing price in the annual capacity auction. While the forecast used in this analysis is significantly

lower than CONE it is necessary to consider that capacity prices could reach this level making long term reliance on the capacity market a risk that should be avoided. This consideration is even more relevant due to Zone 7, the lower peninsula of Michigan, clearing at CONE during this year's PRA.

It is a combination of the MISO warnings, the widely varying Consultant forecasts and the risks associated with an illiquid market that suggests to Vectren that the best way to mitigate the capacity market risk is through building Combustion Turbines for capacity rather than rely heavily on the market.

7.2.4 Additional Modeling Considerations

Vectren received approval in 2019 from the Commission to upgrade F.B. Culley 3, Vectren's most efficient coal unit, for continued operations. As such, the unit was modeled with continued operations throughout the planning period. As stated in that case, there is a premium for resilience and diversity with continuing to run the Culley unit. Based on updated reference case modeling in this IRP, that premium is estimated to be about ~0.5% in total NPV for continuing to run the plant through 2034. Vectren has chosen to continue operating this unit for the resiliency that it provides. All other coal units could retire economically within the model beginning December 31, 2023.

Modeling also included other fixed considerations. All candidate portfolios were designed to include the first five selectable energy efficiency bins, corresponding to 1.25% of energy efficiency, in the near-term years of 2021-2023. The model also included one fixed low-income bundle and one fixed demand response bundle (an air conditioning direct load control measure to a smart thermostat measure). Vectren's coal units were modeled to dispatch to LRZ6 on the basis of full variable costs (fuel, emissions, VOM) in the years 2019-2023, while dispatching to serve native load on the basis of fuel only in these same years. All coal units (whether selected to continue or not) were modeled to dispatch to full variable costs to LRZ6 and Vectren from 2024 through the end of the forecast period (2039). Long term annual capacity market purchases were limited to ~180 MW.

While a dynamic peak capacity credit (automatically adapting to the penetration level of solar and wind resources in MISO) proved to be challenging to implement in Aurora, Vectren's modeling efforts did include a seasonal, declining peak capacity credit for both solar and wind resources. Summer solar peak capacity credit began at 29% in 2023 (the first year in which new solar resources are available) and declined to 17% by 2039, while winter solar peak capacity credit began at 7% in 2023 and declined to 4% in 2039. Summer wind peak capacity credit began at 7.23% in 2022 (the first year in which new wind resources are available) and declined to 6.62% by 2039, while winter wind peak capacity credit began at 16.1% in 2022 and declined to 14.74% in 2039. Battery storage was modeled with a 95% peak capacity credit. Non-bid solar and Non-bid wind resources were not permitted until 2025 after short-term renewable and storage PPAs were no longer available.

Additional modeling parameters were included to account for logistical, commercial and operational limitations. These included limiting wind energy resources to 400 MW per year, wind plus storage resources to 150 MW per year, solar photovoltaic resources to 500 MW per year, solar plus storage resources to 150 MW per year, lithium-ion battery storage resources to 300 MW per year and flow battery storage to 400 MW per year. Combined cycle gas resources were limited to one unit per year, while simple cycle gas turbine resources were limited to a total of three units. Combined heat and power (CHP), reciprocating engines and aeroderivative gas turbines were excluded as resource options on the basis of lack of a dedicated facility for steam in the case of CHP and for technical considerations (for example, gas pipeline pressure requirements and cost) in the case of aeroderivatives.

7.3 ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren used a construct that allowed for increasing regulatory restrictions across four alternative scenarios. As previously mentioned, there were two purposes for these scenarios. First,

each alternative market scenario was used to develop a least cost portfolio. Second, the final list of portfolios was evaluated against each alternative market scenario.

The alternate scenarios were created with increasing order of regulatory restriction included the Low Regulatory scenario, the High Technology scenario, the 80% Reduction in CO_2 scenario and the High Regulatory scenario. Pace Global provided the qualitative descriptions and quantitative inputs for each of these scenarios, which were based on collaboration between Vectren, Pace and stakeholders.

Each of the four alternative scenarios provided a framework of market inputs in which a least cost portfolio solution was developed. Of the four scenario based portfolios that were developed, only the High Technology portfolio was selected for further analysis.

The High Technology portfolio provided a useful boundary condition on the Reference Case, relying on a second combustion turbine unit, 1,146 MW of solar, 300 MW of wind and 176 MW of storage. The other three alternative scenario based portfolios included significantly greater renewable resources in their respective market scenario conditions than needed to serve Vectren customers under reference case conditions. In these three scenarios that were not selected for further analysis, the portfolios selected as least cost assumed large quantities of off-system sales in order to reduce portfolio costs. The high level of sales associated with these portfolios precluded them from further consideration as that was a significant issue raised in several of the portfolios in the 2016 study in the Director's report.

For example, the Low Regulatory portfolio included higher load and higher gas prices than in the Reference Case. However, the portfolio (optimized to those different market conditions) included 2,146 MW of solar, 2,700 MW of wind, 126 MW of battery storage and a relatively heavy reliance on capacity market purchases, in addition to F.B. Culley 3 and one new CT.

The least cost 80% Reduction of CO_2 portfolio included 1,946 MW of solar, 3,050 MW of wind and 392 MW of battery storage. Due to the significant increase in late-term renewables buildout, this portfolio saw annual net energy sales climb from 2,500,000 MWhs in 2033 to over 9,300,000 MWhs by 2039.

The least cost High Regulatory portfolio included 2,956 MW of solar, 3,600 MW of wind and 618 MW of battery storage. Due to the heavy buildout of renewables, this portfolio reached 10,000,000 MWh of annual net energy sales by 2029 and stayed above this level for the remainder of the study period.

7.3.1 Description of Alternate Scenarios

As described in Section 2.4, the second purpose of developing these "boundary" scenarios was to test a relevant range for each of the key market drivers (gas, coal, CO_2, load and capital costs) on how various technologies perform under boundary conditions.

7.3.1.1 Low Regulatory

The Low Regulatory scenario is meant to be a lower boundary scenario in which there is a general laissez-faire attitude toward regulations. In the Low Regulatory scenario, only the ACE rule is included for CO_2 regulation and remains in place throughout the forecast. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3).

In this scenario, fewer regulations are expected to result in a better economy and higher load. Gas prices are expected to move upward with increased demand, while coal prices continue to remain at Reference Case levels as demand for coal continues to decline nationally due to investor pressure and demand for cleaner alternatives. Technology capitals costs are expected to continue to decline at Reference Case levels.

Energy efficiency costs are expected to net to the Reference Case level. There is downward pressure with fewer codes and standards being implemented, leaving some low hanging fruit, but upward pressure with increasing load, netting to no change from the Reference Case level.

7.3.1.2 High Technology

The High Technology scenario was constructed to be indicative of significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency gas-fired generation and natural gas extraction productivity. Overall, there are significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth.

The High Technology scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to become more competitive. A relatively low CO_2 tax is implemented in this scenario. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the CO_2 tax. The increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the Reference Case. There is less demand for coal, which results in lower prices relative to the Reference Case. In addition, utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below Reference Case levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy.

As technology costs fall, customers begin to move towards electrification, driving increased electric vehicle sales and higher adoption of rooftop distributed solar and battery storage, which trend towards highly efficient electric heat pumps in new homes.

7.3.1.3 80% CO_2 Reduction by 2050

The 80% CO_2 Reduction by 2050 scenario assumes that a carbon cap regulation is implemented, which mandates an 80% reduction of CO_2 by 2050 from 2005 levels. A glide path is then set based on a gradual ratcheting-down of CO_2 emissions and an increasing CO_2 allowance cost.

In this scenario, load decreases as the costs for energy and backup power increase and as the energy mix transitions into areas such as increased electrification. In this scenario, regulations on methane emissions initially drive up gas prices, but are partially offset by increased supply. The price of natural gas remains on par with the Reference Case. However, there is less demand for coal, which drives prices lower than the Reference Case. Some large and efficient coal plants remain as large fleets can comply with the regulation on a fleet wide basis.

Renewable energy and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns. Market-based solutions are implemented to lower CO_2. Innovation continues to occur but is offset by more codes and standards with no incentives. As a result, energy efficiency costs rise.

7.3.1.4 High Regulatory

The High Regulatory scenario is characterized by a more heavily regulated path. The High Regulatory path is indicative of the following plausible circumstances relative to the Reference Case:

- A much higher cost for compliance with emissions controls, which begins virtually immediately in 2022 at $50/short ton of CO_2;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the Reference Case, including a potential expansion of carbon costs not only at

the upstream level (which is relatively efficient to administer across a few thousand producers) but also on the downstream level (which is much less efficient to administer across millions of consumers, a policy that is adopted to force through more rapid change);

- Greater adoption of distributed generation in the form of solar and combined heat and power; and
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices and result in an additional push and economic case for renewable energy.

The social cost of carbon is implemented via a high CO_2 tax early in the scenario. Monthly rebate checks (dividends) help to redistribute the revenues from the tax to American households based on number of people in the household. Furthermore, a fracking ban is imposed, driving up the cost of natural gas to historical levels last seen in the pre-shale boom era (pre-2008) in the long-term as supply dramatically shrinks (quantitatively, the price path is +2 standard deviations above current levels). For coal, a strong decline in demand puts downward pressure on coal prices.

The economic outlook remains at the Reference Case level as any potential benefit of the CO_2 dividend is offset by the drag on the economy imposed by additional regulations, including the fracking ban. Innovation occurs as renewables and battery storage are widely implemented to avoid paying high CO_2 prices, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

7.3.2 Coordinated Forecasts for Alternate Scenarios

The qualitative description of alternate scenarios described in Section 7.3.1 were next translated into quantitative inputs for use as modeling inputs. The steps in this process were described in Section 2.

- Stochastic distributions were developed for each input variable

- A table was developed that determined whether the variable would be above or below the Reference Case in the short, mid and long term.
- Values in specific years were developed by moving up or down one standard deviation (for gas sometimes two standard deviations) from the mean or reference forecast.
- Smoothing occurred to reach interim year values.

This was done using a probabilistic modeling framework, described below, which allowed the development of higher and lower forecasts, relative to the Reference Case for natural gas prices, CO_2 prices, coal prices, average and peak load for Vectren as well as surrounding markets (MISO, PJM and SERC) and capital costs for renewables, storage and fossil technologies.

7.3.2.1 Stochastic Distributions

In order to perform the probabilistic modeling, also known as stochastic analysis, a set of probability distributions were required for the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in the Technical Appendix 11.6.

7.3.2.1.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and SERC. Pace Global' s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather and the possible disruptive impacts of energy efficiency penetration in constructing the average and peak demand outlook. Pace Global benchmarked the projections against MISO-sponsored load

forecasting studies that are conducted by independent consultants, institutions and market monitors and then released into the public domain.

7.3.2.1.2 Gas Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

7.3.2.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on a consensus Reference Case view of coal prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the NYMEX. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

7.3.2.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance

requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the Northeast) to estimate the parameters for developing carbon costs distributions.

7.3.2.1.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

7.3.2.1.6 Cross-Commodity Stochastics

Pace Global captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from

historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

7.3.2.2 Model Inputs

The following graphs illustrate the key market driver inputs across all the alternate scenarios.

Figure 7.8 – Vectren Peak Load (MW) Alternate Scenarios

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,115	1,115	1,115	1,115	1,115
2020	1,100	1,100	1,100	1,100	1,100
2021	1,102	1,102	1,102	1,102	1,102
2022	1,126	1,146	1,146	1,084	1,126
2023	1,168	1,191	1,191	1,066	1,168
2024	1,173	1,235	1,235	1,049	1,173
2025	1,176	1,303	1,303	1,055	1,176
2026	1,179	1,325	1,325	1,045	1,179
2027	1,183	1,322	1,322	1,036	1,183
2028	1,189	1,348	1,348	1,028	1,189
2029	1,192	1,338	1,338	1,035	1,192
2030	1,196	1,337	1,337	1,059	1,196
2031	1,200	1,356	1,356	1,055	1,200
2032	1,205	1,371	1,371	1,055	1,205
2033	1,209	1,386	1,386	1,056	1,209
2034	1,214	1,356	1,356	1,051	1,214
2035	1,219	1,379	1,379	1,051	1,219
2036	1,225	1,379	1,379	1,065	1,225
2037	1,229	1,383	1,383	1,060	1,229
2038	1,234	1,386	1,386	1,076	1,234
2039	1,239	1,391	1,391	1,062	1,239

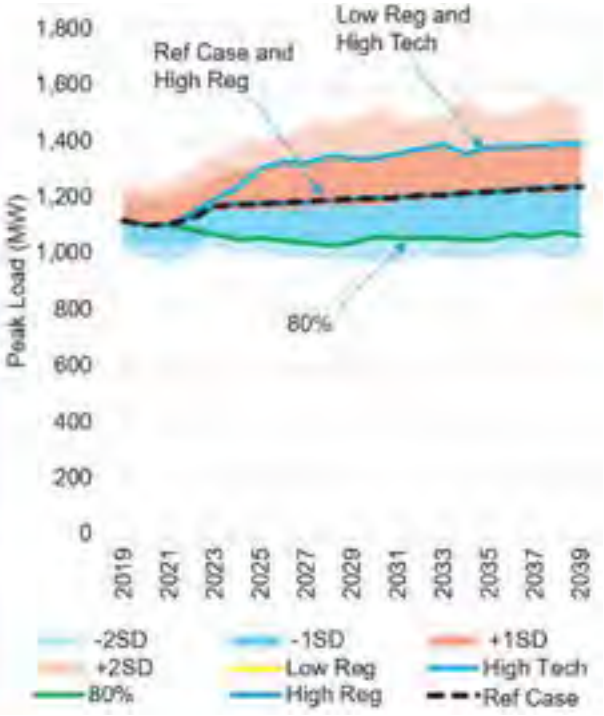


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1.78	1.78	1.78	1.78	1.78
2020	1.68	1.68	1.68	1.68	1.68
2021	1.66	1.66	1.66	1.66	1.66
2022	1.65	1.65	1.57	1.57	1.57
2023	1.64	1.64	1.49	1.49	1.49
2024	1.64	1.64	1.41	1.41	1.41
2025	1.63	1.63	1.27	1.27	1.27
2026	1.62	1.62	1.29	1.29	1.29
2027	1.61	1.61	1.25	1.25	1.25
2028	1.62	1.62	1.25	1.25	1.25
2029	1.61	1.61	1.25	1.25	1.25
2030	1.60	1.60	1.25	1.25	1.25
2031	1.59	1.59	1.25	1.25	1.25
2032	1.58	1.58	1.25	1.25	1.25
2033	1.58	1.58	1.25	1.25	1.25
2034	1.57	1.57	1.25	1.25	1.25
2035	1.59	1.59	1.25	1.25	1.25
2036	1.59	1.59	1.25	1.25	1.25
2037	1.59	1.59	1.25	1.25	1.25
2038	1.59	1.59	1.25	1.25	1.25
2039	1.58	1.58	1.25	1.25	1.25

A price floor is set at $1.25/MMBtu

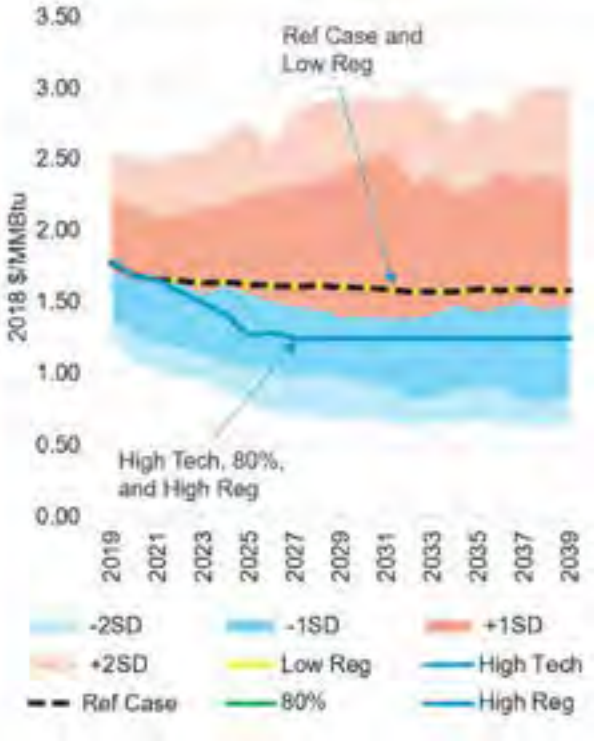


Figure 7.10 – $C0_2$ Alternate Scenarios (2018$/ton)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	49.46
2023	0	0	0	0	50.40
2024	0	0	0	0	51.34
2025	0	0	1.20	3.57	52.28
2026	0	0	1.44	4.08	53.23
2027	3.57	0	2.06	5.10	54.17
2028	4.08	0	2.28	6.12	55.11
2029	5.10	0	2.38	6.63	56.05
2030	6.12	0	2.68	7.14	56.99
2031	6.63	0	2.94	7.65	57.94
2032	7.14	0	3.17	8.16	58.88
2033	7.65	0	3.89	9.18	60.06
2034	8.16	0	4.49	10.20	61.23
2035	9.18	0	5.46	11.22	62.41
2036	10.20	0	6.01	12.75	63.59
2037	11.22	0	6.85	14.79	64.77
2038	12.75	0	7.52	17.34	65.94
2039	14.79	0	8.50	19.89	67.12

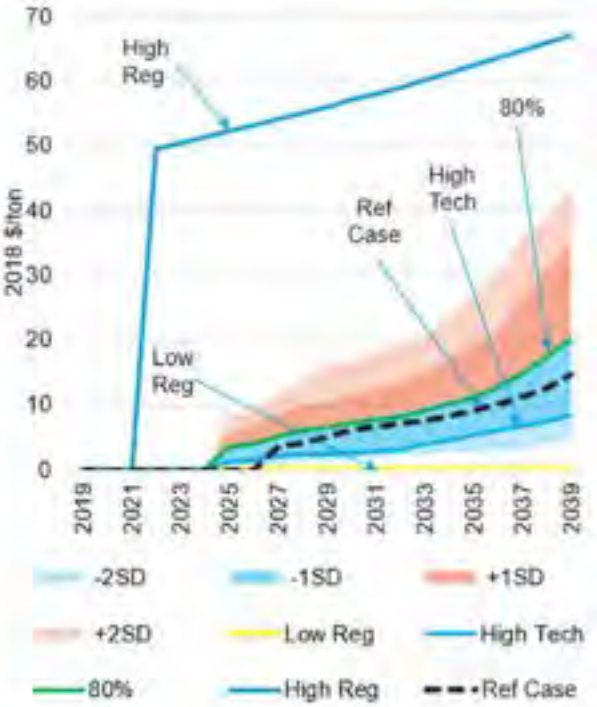


Figure 7.11 – Natural Gas (Henry Hub) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.77	2.77	2.77	2.77	2.77
2020	2.66	2.66	2.66	2.66	2.66
2021	2.76	2.76	2.76	2.76	2.76
2022	2.89	3.46	3.01	2.89	3.58
2023	3.06	4.10	2.82	3.06	4.39
2024	3.16	4.75	2.64	3.16	5.21
2025	3.24	5.12	2.33	3.24	6.03
2026	3.33	5.27	2.08	3.33	7.14
2027	3.38	5.20	2.13	3.38	7.10
2028	3.44	5.45	2.06	3.44	7.43
2029	3.49	5.62	2.04	3.49	8.37
2030	3.55	5.77	2.12	3.55	7.53
2031	3.62	5.60	2.13	3.62	7.17
2032	3.69	5.76	1.97	3.69	7.89
2033	3.78	5.95	2.02	3.78	8.40
2034	3.85	6.02	1.95	3.85	7.49
2035	3.96	6.12	2.12	3.96	8.95
2036	4.02	6.64	2.12	4.02	9.29
2037	4.09	6.23	2.07	4.09	8.75
2038	4.14	6.77	2.19	4.14	9.07
2039	4.17	6.85	2.20	4.17	8.63

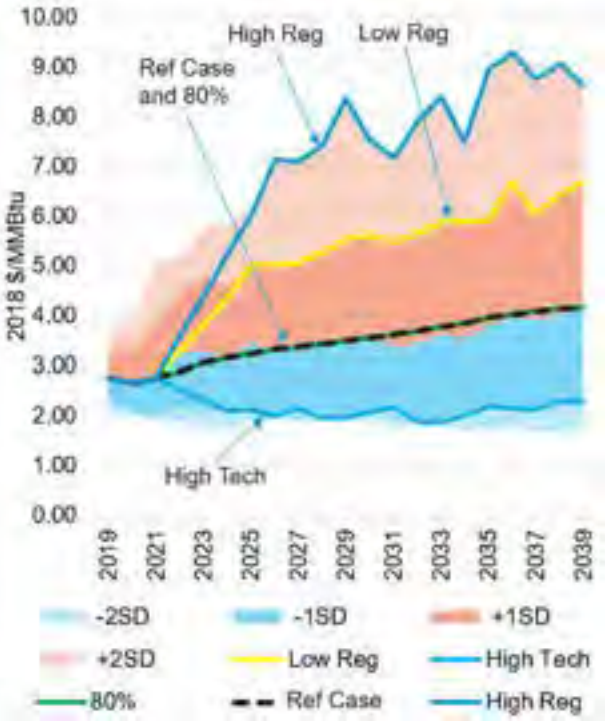


Figure 7.12 – Solar Capital Costs Alternate Scenarios(100 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,384	1,384	1,255	1,255	1,255
2020	1,305	1,305	1,160	1,160	1,160
2021	1,237	1,237	1,093	1,093	1,093
2022	1,198	1,198	1,043	1,043	1,043
2023	1,179	1,179	1,008	1,008	1,008
2024	1,161	1,161	996	996	996
2025	1,143	1,143	954	954	954
2026	1,124	1,124	956	956	956
2027	1,106	1,106	943	943	943
2028	1,089	1,089	949	949	949
2029	1,072	1,072	921	921	921
2030	1,057	1,057	887	887	887
2031	1,041	1,041	878	878	878
2032	1,028	1,028	871	871	871
2033	1,016	1,016	858	858	858
2034	1,003	1,003	817	817	817
2035	990	990	801	801	801
2036	981	981	790	790	790
2037	972	972	792	792	792
2038	962	962	789	789	789
2039	952	952	800	800	800

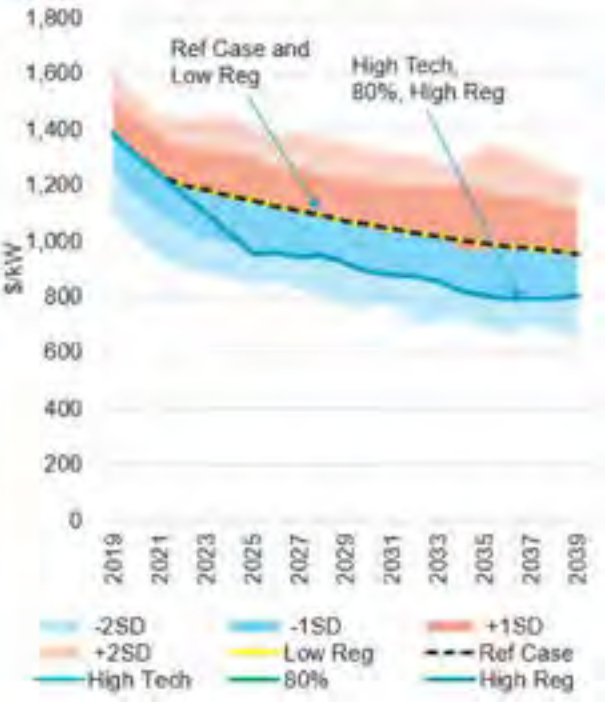


Figure 7.13 – Wind Capital Costs Alternate Scenarios (200 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,334	1,334	1,334	1,334	1,334
2020	1,332	1,332	1,332	1,332	1,332
2021	1,330	1,330	1,330	1,330	1,330
2022	1,329	1,329	1,289	1,289	1,289
2023	1,328	1,328	1,249	1,249	1,249
2024	1,327	1,327	1,208	1,208	1,208
2025	1,326	1,326	1,167	1,167	1,167
2026	1,325	1,325	1,163	1,163	1,163
2027	1,324	1,324	1,123	1,123	1,123
2028	1,324	1,324	1,157	1,157	1,157
2029	1,324	1,324	1,160	1,160	1,160
2030	1,324	1,324	1,182	1,182	1,182
2031	1,324	1,324	1,152	1,152	1,152
2032	1,324	1,324	1,152	1,152	1,152
2033	1,324	1,324	1,166	1,166	1,166
2034	1,325	1,325	1,161	1,161	1,161
2035	1,326	1,326	1,139	1,139	1,139
2036	1,327	1,327	1,129	1,129	1,129
2037	1,328	1,328	1,142	1,142	1,142
2038	1,329	1,329	1,142	1,142	1,142
2039	1,330	1,330	1,143	1,143	1,143

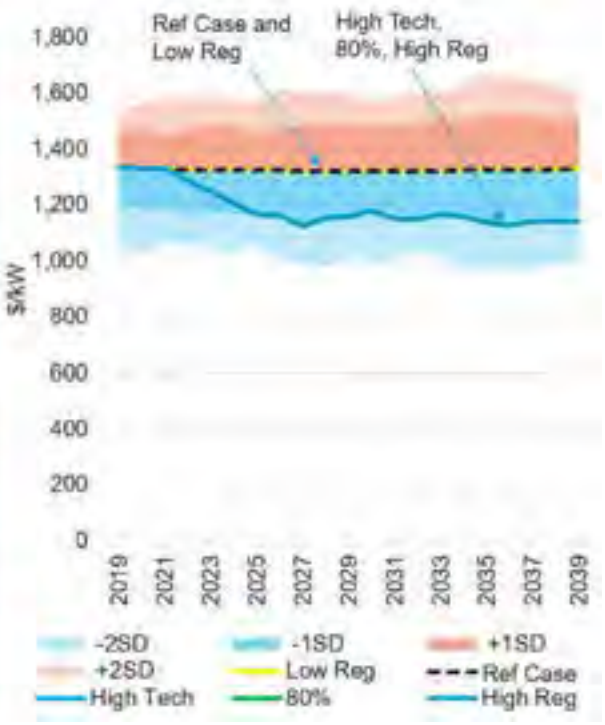
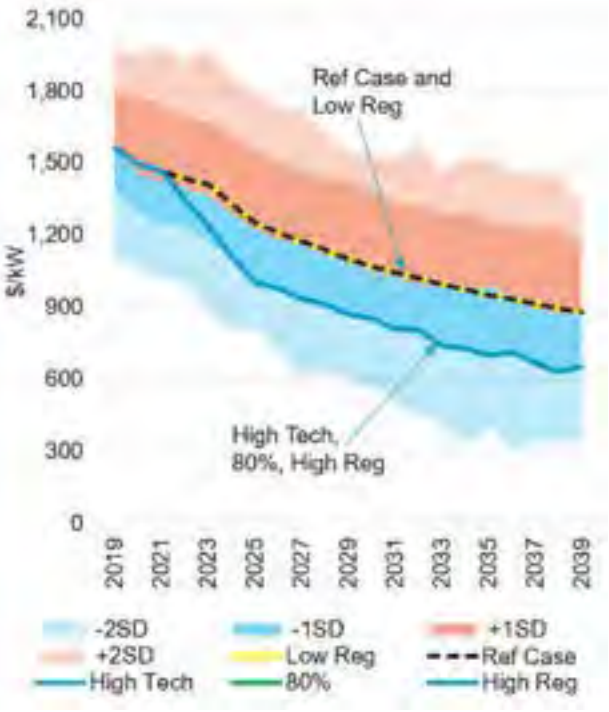


Figure 7.14 – Lithium-Ion 50 MW / 200 MWh Battery Storage Capital Costs Alternate Scenarios (2018$/kW)[41]

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,562	1,562	1,390	1,390	1,390
2020	1,498	1,498	1,299	1,299	1,299
2021	1,467	1,467	1,247	1,247	1,247
2022	1,439	1,439	1,236	1,236	1,236
2023	1,412	1,412	1,178	1,178	1,178
2024	1,332	1,332	1,100	1,100	1,100
2025	1,252	1,252	1,001	1,001	1,001
2026	1,209	1,209	982	982	982
2027	1,175	1,175	936	936	936
2028	1,140	1,140	916	916	916
2029	1,103	1,103	869	869	869
2030	1,068	1,068	852	852	852
2031	1,044	1,044	811	811	811
2032	1,020	1,020	806	806	806
2033	996	996	739	739	739
2034	975	975	727	727	727
2035	951	951	699	699	699
2036	933	933	714	714	714
2037	915	915	669	669	669
2038	897	897	631	631	631
2039	878	878	654	654	654



[41] Note that storage costs were updated since the October 10th stakeholder meeting and are lower

SECTION 8
PORTFOLIO DEVELOPMENT AND EVALUATION

8.1 PORTFOLIO DEVELOPMENT

Vectren developed a wide range of portfolios for scenario modeling in the dispatch module of Aurora and ultimately for the probabilistic modeling portion of this IRP process. Working with external stakeholders and building upon feedback from the IURC Director's Report from the 2016 IRP, Vectren developed 15 "least cost" portfolios for evaluation that included the continuing use of coal plants (status quo) for comparative cost and performance benchmarking purposes, scenario-based portfolios optimized under widely varying market conditions, bridge portfolios designed to take advantage of existing resources during the transition to a generation fleet with many new resources, diversified portfolios with a balanced mix of generation technology types and renewables-focused portfolios designed with directed input from stakeholders. Each least cost portfolio was constructed with the option to include near-term solar, wind and battery storage options, from the All-Source RFP solicitation, while medium-term and long-term resource options were available for selection from a comprehensive technology assessment performed by Burns & McDonnell (with capital costs developed from a consensus view of prices from Burns & McDonnell, Pace Global and NREL for renewable and storage options). These resource portfolios were then selected on a least-cost basis using the LTCE module of the Aurora model. DSM resource options were also available for selection

8.1.1 Portfolio Strategies with Stakeholder Input

Vectren strived to take into consideration the many diverse interests of a broad range of stakeholders. Accordingly, several of the 15 candidate portfolios were developed with direct and indirect input from stakeholders. Three portfolios were designed to be focused on renewables, including a Renewables 2030 portfolio in which all fossil generation is retired at the end of 2029; a Renewables plus Flexible Gas portfolio, that includes closing F.B. Culley 3 by December 31, 2033 and excludes any new gas combined cycle plants; and an HB 763 portfolio modeled after a bill in the U.S. Congress that includes a CO_2 price in 2022 of $15, increasing by $10 per short ton each year (approximately $200 by 2039). Other portfolios, including the Business as Usual and Bridge portfolios, were designed to consider the interests of a separate set of stakeholders.

8.1.2 Least Cost Portfolio Construction

Each of the 15 strategies were utilized to construct portfolios in the Aurora model using a Least Cost Capacity Expansion module in AURORA with a cost minimization objective function. The scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) each selected the lowest cost combination of assets assuming their respective market inputs. In Section 7 it is noted that three of those portfolios were eliminated from consideration because they employ greater capacity than needed in the form of renewable resources and rely on extensive off-system sales to reduce costs.

Other portfolios were determined by forcing certain design considerations for specific generating stations, including bridge options that include converting existing coal units into gas peaking units or extending the life of A.B. Brown coal units and then the model selected the least cost portfolio of remaining assets. Vectren also constructed in diverse energy portfolios with two sizes of gas combined cycle technologies and portfolios focused primarily on renewable and battery storage technologies. Utilizing this strategy allowed for a wide range of portfolios that were least cost portfolios using available resources, subject to initial design parameters in each strategy. All portfolios were also designed to include five (5) blocks of near-term (2021-2023) energy efficiency, which is equivalent to approximately 1.25% of eligible retail sales. Each portfolio description below details the optimized amount of EE selected.

8.1.3 Portfolio Descriptions

The following sections describe in detail designed portfolios (including bridge, diverse and renewables-focused portfolios). Figure 8.1 Portfolio Details shows a summary table of the build outs for each of the selected set of portfolios for consideration in the Risk Analysis. Note that the last line of each table shows long-term capacity market exposure under reference case conditions. Also, based on a sensitivity described in Section 8.2.2 near-term energy efficiency of 1.25% included in all portfolios.

Figure 8-1 – Portfolio Details

Year	Reference Case	Business as Usual to 2039	Business as Usual to 2029	Gas Conversion ABB1	Gas Conversion ABB1 + ABB2
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Scrubber control on ABB1 and ABB2, Exit Warrick (150 MW)	Exit Warrick (150 MW)	Retire ABB2, FBC2, Exit Warrick (485 MW)	Retire FBC2, Exit Warrick (240 MW)
2024	New Combustion Turbine (236 MW)	-	-	ABB1 Conversion (245 MW)	ABB1+ABB2 Conversions (490 MW)
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency
2027-39	0.75% Energy Efficiency	0.25% Energy Efficiency	0.50% Energy Efficiency	0.75% Energy Efficiency	0.50% Energy Efficiency
2029-30	-	-	Retire ABB1, ABB2, FBC2 (580 MW), New Combustion Turbine (236 MW)	-	-
2033-34	-	-	-	Retire ABB1, New Combustion Turbine (279 MW)	Retire ABB1+ABB2, New Combustion Turbine (279 MW)
2037-39	New Solar (250 MW)	-	-	-	-
2024-39	Avg Annual Capacity Mkt Purchases (137 MW)	No Capacity Market Purchases	Avg Annual Capacity Mkt Purchases (101 MW)	Avg Annual Capacity Mkt Purchases (133 MW)	Avg Annual Capacity Mkt Purchases (56 MW)

Year	Gas Conversion ABB1 + CCGT	Diverse Small CCGT	Diverse Medium CCGT	Renewables + Flexible Gas	Renewables 2030
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (278 MW)
2023	Retire ABB2, FBC2, Exit Warrick (485 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	ABB1 Conversion (245MW)	-	-	New Combustion Turbine (236 MW)	-
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2025	-	New Small CCGT (433 MW)	New Medium CCGT (497 MW)	-	-
2026	New Small CCGT (433MW)	-	-	-	-
2024-26	0.50% Energy Efficiency	0.50% Energy Efficiency	0.25% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2029-32	-	-	-	-	Retire FBC3, ABB3, ABB4 (427 MW), New Storage (360 MW), Solar (700 MW)
2033-34	-	-	-	Retire FBC3 (270 MW), New Combustion Turbine (236 MW)	New Solar (450 MW)
2024-39	Avg Annual Capacity Mkt Purchases (18MW)	Avg Annual Capacity Mkt Purchases (23 MW)	Avg Annual Capacity Mkt Purchases (18 MW)	Avg Annual Capacity Mkt Purchases (135MW)	Avg Annual Capacity Mkt Purchases (170MW)

Year	HB 763	Low Regulatory	High Technology	80% Reduction of CO2 by 2050	High Regulatory
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (202 MW)	New Solar (731 MW) New Storage (278 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	New Landfill Gas (27 MW)	New Combustion Turbine (279 MW)	New Combustion Turbine (236 MW)	-	-
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	1.50% Energy Efficiency	1.25% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	1.25% Energy Efficiency
2025	New Solar (550 MW) New Wind (650 MW) New Storage (50 MW)	-	New Combustion Turbine (236 MW)	-	New Solar (550 MW) New Wind (650 MW) New Storage (50 MW)
2026-39	New Solar (1,100 MW) New Wind (2,500 MW) New Storage (220 MW)	New Solar (1,000 MW) New Wind (2,400 MW)	-	-	New Solar (1,260 MW) New Wind (2,650 MW) New Storage (290 MW)
2027-39	1.25% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency	0.5% Energy Efficiency	0.50% Energy Efficiency
2033-39	-	-	New Storage (50 MW)	New Solar (800 MW) New Wind (2,750 MW) New Storage (190 MW)	-
2024-39	Avg Annual Capacity Mkt Purchases (10 MW)	Avg Annual Capacity Mkt Purchases (12 MW)	Avg Annual Capacity Mkt Purchases (4 MW)	Avg Annual Capacity Mkt Purchases (203 MW)	Avg Annual Capacity Mkt Purchases (11 MW)

8.1.3.1 Reference Case

The Reference Case is considered to be the “most likely” case, built with commodity forecasts based on a consensus outlook from industry experts as described in Section 7.2 Reference Case Scenario.

The least cost Reference Case portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW CT selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 137.5 MW during the period 2024-2039. Finally, 250 MW of solar is selected in the final three years of the forecast (2037-2039).

8.1.3.2 Status Quo

The BAU to 2039 status quo portfolio was designed, by definition, to provide a business as usual outlook through the forecast period. In this portfolio, each of the four Vectren-owned coal generation units are kept in operation to 2039, subject to various upgrades to keep them in compliance with existing environmental regulatory requirements. The Warrick 4 unit was given the option to extend for an additional three years of operation before exiting the joint agreement, but ultimately was not selected by the optimization routine for continuation based on purely economic considerations. This portfolio provides a useful, status quo benchmark for financial and operational performance to compare against all the other candidate portfolios. Vectren exits Warrick 4 joint operations with Alcoa. This 150 MWs is replaced with renewables. The optimized (least costs) BAU to 2039 portfolio includes 300 MW of wind resources selected in 2022, approximately 746

MW of solar selected in 2023 and 2024 and the selection in 2023 of paired "solar plus storage" resources (400 MW solar; 126 MW storage). Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while an additional block of EE (0.25%) is selected in the time period 2024-2026. This portfolio is capacity-rich, so no capacity market purchases are required during the period 2024-2039.

8.1.3.3 Four Scenario Based Portfolios

Four scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions and technological progress. In general, the scenario-based portfolios move from low to high regulation, with intermediate levels of regulation characterized by the High Technology and 80% Reduction of CO_2 portfolios.

While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to bookend the Reference Case with higher than, lower than, or similar inputs to the Reference Case. The following sections describe the qualitative and quantitative development of the scenario-based portfolios.

8.1.3.3.1 Low Regulatory

The Low Regulatory portfolio (optimized under high load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 279.3 MW CT is selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,000 MW of solar is selected beginning in 2026, while an additional 2,600 MW of wind is selected beginning in 2032. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional block (0.25%) of energy efficiency is selected in the time period 2024-2026 and the optional demand response bin is selected in the time periods 2024-2026 and 2027-

2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 18.4 MW during the period 2024-2033. Because the Low Regulatory portfolio was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.2 High Technology

The High Technology portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and two new 236.6 MW gas CT is selected in 2024 and 2025, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 50 MW of storage is selected in the final year of the forecast. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized High Technology portfolio buildout had less reliance on the capacity market than the Reference Case portfolio, it offered a useful comparison of cost and performance. It was selected for further analysis and was eventually selected as the preferred portfolio.

8.1.3.3.3 80% CO_2 Reduction

The 80% Reduction of CO_2 by 2050 portfolio (least cost under reference case load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 800 MW of solar is selected beginning in

2035, an additional 2,750 MW of wind is selected beginning in 2033 and an additional 266 MW of battery storage is selected beginning in 2036. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized 80% Reduction of CO_2 by 2050 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.4 High Regulatory

The least cost High Regulatory portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, approximately 152 MW of storage in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,810 MW of solar is selected beginning in 2025, an additional 3,300 MW of wind is selected beginning in 2025 and an additional 340 MW of battery storage (which is paired with wind) is selected beginning in 2025. Approximately 1.25% of energy efficiency blocks are selected in the first two time periods (near-term 2021-2023 and mid-term 2024-2026), while 0.50% of energy efficiency is selected in the time period 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 165.6 MW of capacity market purchases. Because the optimized High Regulatory portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.4 Bridges

The following portfolios were designed to serve as bridge portfolios, offering short-term and long-term transition pathways toward a fleet with greater renewable resources while utilizing existing resources.

8.1.3.4.1 Gas Conversion ABB1

This portfolio was designed to include the conversion of the older, less efficient unit at the A B Brown plant from a baseload coal-fired to natural gas peaking, which helps to preserve and repurpose much of the existing asset base. The unit would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. Conversions utilize some old equipment and require on-going capital investments to keep the units running. Since conversion of a unit offers less flexibility with slow start time (8-24 hrs.) and slow ramp rate (2MW/Min) it does not complement renewables well. The one conversion unit and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the conversion in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039). The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 133.3 MW during the period 2024-2033.

8.1.3.4.2 Gas Conversion ABB1 & ABB2

Similar to the Gas Conversion ABB1 portfolio, this portfolio was designed to include the conversion of both units at the A B Brown plant from baseload coal-fired units to natural gas peaking units. These conversions also help to preserve and repurpose much of the existing asset base at this facility. As described above, gas conversion units do not start or ramp quickly. Both units would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. The two conversion units and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 & ABB2 portfolio retired F B Culley 2 and exited joint operations at Warrick 4. and includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the two conversions in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2027-2039 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 150.1 MW during the period 2034-2039.

8.1.3.4.3 Gas Conversion ABB1 + CCGT

This portfolio was designed to include conversion of one unit at the A B Brown plant from a baseload coal-fired unit to a natural gas peaking unit, which helps to preserve and repurpose much of the existing asset base at this facility. It retired A B Brown unit 2, F B Culley 2 and exited joint operations at Warrick 4. In addition, this portfolio includes a small CCGT unit with duct-firing capability (total 442.5 MW) in 2026. The conversion unit is be converted for operation beginning in 2024 and is expected to operate for 10 years before

retirement. The conversion and CCGT units are the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 + CCGT portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and the conversion unit in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 432.6 MW combined cycle unit is designed to begin operations in 2026. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2024-2026 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 16.4 MW during the period 2024-2039.

8.1.3.4.4 BAU 2029

The BAU 2029 portfolio was designed to bridge half of the study period (2019-2029) using existing baseload coal resources at A B Brown plant. Culley 2 (90 MW) is retired in 2023 and Vectren exits joint operations of Warrick 4 (150 MW) in 2023. The two coal units at A B Brown are extended through 2029 using existing FGD scrubber technology and retired by 2030. This portfolio strategy helps to preserve the existing asset base while providing a transition pathway to a generation fleet with greater renewable resources. The two coal unit extensions through 2029 is the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost BAU 2029 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW gas

CT is selected in 2030. The coal unit F B Culley 2 and Warrick 4 are selected for retirement or exit of joint operations beginning in 2024. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026 and 2027-2039. The optional demand response bin is selected in the time period 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 162.4 MW during the period 2030-2039.

8.1.3.5 Diverse

The following portfolios were designed to serve as portfolios that offer a diverse mix of baseload, peaking and intermittent technologies as well as a diversity of fuel sources including coal, natural gas and renewables.

8.1.3.5.1 Small CCGT with Renewables and Coal

The Small CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a small-sized CCGT with duct-firing capability (total 442.5 MW). This portfolio strategy provides a transition pathway to a generation fleet, while maintaining and adding a diverse fuel mix of baseload generation technology. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations at Warrick 4. The CCGT unit and the near-term (2021-2023), keeping Culley 3, and the selection of renewables, storage and DSM options were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Small CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new small-sized CCGT with duct-firing capability (total 442.5 MW) that begins in

2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time periods 2024-2026 and 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operations, but thereafter any capacity shortfall is minimal and met through capacity market purchases, which average 21.5 MW during the period 2036-2039.

8.1.3.5.2 Mid CCGT with Renewables and Coal

The Mid CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a medium-sized CCGT with duct-firing capability (total 510.7 MW). This portfolio strategy provides a transition pathway to a generation fleet with greater renewable resources while maintaining and adding a diverse mix of fuels and a diverse mix of baseload, peaking and intermittent generation technologies. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations of Warrick 4. The CCGT unit, keeping Culley 3 and the selection of renewables and storage were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Mid CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new medium-sized CCGT with duct-firing capability (total 510.7 MW) that begins in 2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operational, but thereafter any capacity shortfall is minimal and met through capacity market purchases,

which occur only in 2039 and equal 3 MW. Because this portfolio did not produce a meaningful distinction with the optimized least cost Small CCGT with Renewables and Coal portfolio other than increased cost, with limited performance benefits, this portfolio was not selected for further analysis.

8.1.3.6 Renewables Focused

The following portfolios were designed to include a primary focus on renewable and battery storage resources, using three strategies: (1) closing all fossil by 2030 and backfilling only with renewables and battery storage resource, (2) closing all coal units by 2034 and backfilling with flexible units (CTs) and renewables and (3) optimizing a renewables-focused portfolio using a very high CO_2 price (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching ~$200 by 2039. The third portfolio strategy (HB 763) was included for initial analysis based on direct feedback from stakeholders through the public stakeholder process.

8.1.3.6.1 Close All Fossil by 2030

The close All Fossil by 2030 portfolio was designed to transition Vectren's generation fleet to 100% renewables and battery storage beginning in 2030, which requires closing all coal and natural gas peaking units by the end of 2029. This portfolio strategy provides a rapid transition pathway to a generation fleet with 100% renewable and battery storage resources. The requirement that all fossil retire by the end of 2029 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Close All Fossil by 2030 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and approximately 152 MW of battery storage are selected in 2023 and 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. F B Culley 3 and the two

gas peaking units at A B Brown continue operating through 2029 before retiring in 2030. An additional 1,150 MW of solar resources are selected beginning in 2027, while an additional 360 MW of battery storage are selected beginning in 2027. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 169.7 MW during the period 2024-2039.

8.1.3.6.2 Renewables + Flexible Gas (CTs), Close Coal by 2034

The Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio was designed to transition Vectren's generation fleet to renewables and battery storage while also maintaining the flexibility afforded by gas CTs. This portfolio strategy provides a transition pathway to a generation fleet focused on renewable and battery storage resources while maintaining the resource adequacy provided by flexible gas CTs. The requirement that all coal units retire by the end of 2033 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 600 MW of solar resources are selected beginning in 2034. F B Culley 3 operations continue through 2033 before retiring in 2034. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 134.7 MW during the period 2024-2039.

8.1.3.6.3 HB 763

The HB 763 portfolio was designed to incentivize a rapid transition to renewables and battery storage through a very high CO_2 tax (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching $200 by 2039. This portfolio strategy provides a rapid and aggressive transition pathway to a generation fleet focused on renewable and battery storage resources. The CO_2 price and was the only design parameter included in this candidate portfolio beyond EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost HB 763 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,650 MW of solar resources are selected beginning in 2025 and an additional 3,150 MW of wind resources are selected beginning in 2025. F B Culley 3 operations as well as the two gas peaking units at A B Brown plant continue through the forecast period. Approximately 1.25% of energy efficiency blocks are selected in the near-term (2021-2023), approximately 1.50% of energy efficiency blocks are selected in the medium-term (2024-2026) and approximately 1.00% of energy efficiency blocks are selected in the long-term (2027-2039). No optional demand response is selected. A one-year shortfall in capacity in 2024 is met through capacity market purchases, which equal 164.2 MW. Because the optimized HB 763 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, because this portfolio was the only portfolio that showed significant amounts of wind and solar curtailments (reaching as high as 11.8% annually and 21.4% annually, respectively) and because this portfolio had very high annual net energy sales, this optimized portfolio was not selected for further analysis.

8.2 EVALUATION OF PORTFOLIO PERFORMANCE

A total of 15 portfolios were developed in this IRP process, as described above. After an initial process in which a least cost portfolio was selected, 10 of the portfolios were selected as candidate portfolios for further analysis.

Five were screened out. These included three scenario-based portfolios (80% Reduction of CO_2 by 2050, High Regulatory and Low Regulatory) and two additional portfolios optimized around a key feature (Diverse Medium CCGT and HB 763). The scenario-based portfolios were optimized using the long-term capacity expansion module of Aurora within the wide-ranging market inputs described in Section 7, then simulated in the chronological hourly dispatch module of Aurora. However, each of three scenario-based portfolios were shown to be heavily reliant on energy market sales to reduce total portfolio costs (43.3%, 229.1% and 62.9% higher than the Reference Case, respectively, for the 80% Reduction by 2050, High Regulatory and Low Regulatory portfolios). In addition, around-the-clock (ATC) market clearing prices were as much as 77.3% higher than the Reference Case (specifically in the High Regulatory portfolio). Similarly, the Diverse Medium CCGT portfolio produced comparable results to the Diverse Small CCGT portfolio but at additional cost with little to no additional benefit. The HB 763 portfolio new unit capital costs were 382% higher than the Reference Case, which sold $5.3 billion in energy market sales in a market with average ATC power prices 55% higher than the Reference Case. In effect, the very high energy market sales in the High Regulatory and HB 763 would create a merchant utility, while the other portfolios were not expected to offer additional insights beyond the 10 candidate portfolios shown in the Balanced Scorecard. Furthermore, the HB 763 portfolio showed relatively high levels of renewable energy curtailments that were not seen in any other portfolio in the deterministic modeling (and very rarely in the subsequent stochastic modeling, for those candidate portfolios that underwent risk analysis). For these reasons, these five scenarios were not selected for further analysis in the stochastic framework.

Each of the remaining candidate portfolios was then subjected to two different forms of a risk analysis. One was scenario-based and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard.

8.2.1 Scenario Risk Analysis

The IRP requires scenario-based modeling be performed as a part of the risk analysis be performed. In the Scenario Based risk analysis, the remaining ten candidate portfolios that were selected for further analysis were each modeled under each of the four scenarios with their respective market inputs. The following provides a summary of the results of this scenario risk analysis. The results of the deterministic scenario-based Risk Analysis are shown in Figures 8-2 – 8.5 below

Figure 8-2 – Portfolio NPVRR (million $)

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	119.7%	101.2%	120.7%	117.1%	112.5%
Business as Usual to 2029	108.0%	100.9%	108.5%	106.4%	104.8%
ABB1 Conversion + CCGT	112.6%	112.6%	111.5%	111.2%	107.4%
ABB1 Conversion	103.9%	104.5%	104.5%	103.9%	102.0%
ABB1 + ABB2 Conversions	110.0%	110.0%	110.1%	109.9%	105.5%
Diverse Small CCGT	105.3%	105.3%	104.2%	103.5%	102.7%
Renewables + Flexible Gas	98.4%	101.4%	98.2%	98.1%	97.7%
All Renewables by 2030	101.4%	108.2%	105.0%	100.5%	94.3%
High Technology	102.3%	102.6%	101.3%	102.1%	102.2%

Figure 8-3 – Portfolio CO2 Emissions Reductions by 2039 from 2019 Levels (thousand Tons)

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	78.2%	52.0%	87.9%	77.3%	76.4%
Business as Usual to 2039	60.3%	-22.5%	72.6%	54.3%	49.2%
Business as Usual to 2029	74.6%	53.6%	85.9%	74.0%	73.4%
ABB1 Conversion + CCGT	61.5%	40.0%	69.6%	61.8%	62.7%
ABB1 Conversion	74.0%	53.5%	85.6%	73.5%	72.9%
ABB1 + ABB2 Conversions	74.1%	53.5%	85.5%	73.5%	73.0%
Diverse Small CCGT	61.8%	39.8%	69.7%	61.9%	62.7%
Renewables + Flexible Gas	95.2%	90.2%	95.7%	94.9%	91.5%
All Renewables by 2030	95.8%	95.8%	96.0%	95.8%	95.8%
High Technology	77.8%	51.9%	88.2%	77.1%	76.1%

Figure 8-4 – Portfolio Average Market Purchase Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	79.6%	58.1%	97.7%	71.3%	17.1%
Business as Usual to 2029	84.1%	74.5%	90.1%	78.8%	73.5%
ABB1 Conversion + CCGT	38.9%	30.1%	46.0%	42.0%	38.7%
ABB1 Conversion	93.7%	90.9%	103.7%	82.6%	106.1%
ABB1 + ABB2 Conversions	93.2%	89.2%	101.2%	78.1%	104.2%
Diverse Small CCGT	36.2%	26.5%	42.2%	42.2%	35.7%
Renewables + Flexible Gas	108.5%	125.8%	98.9%	106.4%	139.7%
All Renewables by 2030	124.5%	166.1%	134.6%	117.9%	186.1%
High Technology	101.6%	94.0%	89.8%	102.1%	100.9%

Figure 8-5 – Portfolio Average Market Sale Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	141.9%	170.4%	114.9%	170.5%	222.1%
Business as Usual to 2029	129.8%	138.1%	121.3%	139.5%	140.3%
ABB1 Conversion + CCGT	160.4%	161.3%	139.4%	182.1%	136.0%
ABB1 Conversion	104.2%	102.2%	94.2%	113.2%	98.0%
ABB1 + ABB2 Conversions	107.6%	108.5%	99.9%	130.7%	102.0%
Diverse Small CCGT	160.2%	159.7%	139.1%	170.3%	138.9%
Renewables + Flexible Gas	104.7%	99.8%	108.2%	119.0%	97.3%
All Renewables by 2030	128.4%	116.3%	107.4%	143.9%	107.9%
High Technology	96.3%	99.0%	113.8%	94.0%	96.4%

Four portfolios performed very well across all the alternative scenarios and relative to the remaining six candidate portfolios in terms of low cost, low energy sales and purchases and greater CO_2 emissions reductions. These four portfolios included the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios. Each of these portfolios ranked in the top four of 10 portfolios in terms of lowest cost, lowest energy purchases and greatest CO_2 emissions reductions. Similarly, three of these same four portfolios ranked in the top four of 10 portfolios in terms of lowest energy sales (the All Renewables by 2030 portfolio ranked 6th). Accordingly, these four portfolios performed well consistently across the metrics in the Balanced Scorecard[42] and were put forward as final candidates for consideration as the preferred portfolio.

By contrast, the remaining six of 10 portfolios performed relatively less well across these key metrics of portfolio cost, energy sales and purchases and CO_2 emissions reductions. In terms of cost, the BAU to 2039, ABB1 Conversion + CCGT, ABB1 + ABB2 Conversions and BAU to 2029 portfolios were the worst performers, with the notable exception of the two BAU portfolios under Low Regulatory scenario conditions (i.e., no CO_2 price). In terms

[42] Note: The scenario-based risk analysis measured CO_2 emissions reductions rather than CO_2-equivalent emissions reductions.

of CO_2 emissions reductions, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios showed the worst performance due to increased emissions from coal, CCGT, or coal-to-gas conversion unit operations. Finally, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios demonstrated the greatest exposure to market risk in terms of energy sales and purchases. The remaining two portfolios with one or both conversion of the A B Brown coal units performed relatively neither well nor poorly in each of these metrics. While the scenario based risk analysis was not the determinative factor for excluding portfolios or promoting them to final consideration, these results did help to inform the final decision-making process. In the end, all but the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios were eliminated from final consideration.

8.2.2 Sensitivity Analysis

Several sensitivities were conducted on the candidate portfolios to test and refine the design of the portfolios and whether and how results might change if isolated variables might change. The following section describe these sensitivities and the conclusions drawn from this analysis, as well as any impact on the candidate portfolios.

The All-Source RFP resulted in a number of solar, wind and battery storage resources that were included as near-term resources in the optimization module of the Aurora model. A sensitivity was performed in which solar costs were increased by 30% to determine if this would impact their selection in 2022-2024, the timeframe during which they were offered and allowed to be selected in the model. The sensitivity showed that even with an increase of 30% in cost, the portfolio cost increased by 3.99% but the offerings remained below the market-clearing on-peak locational marginal price for Indiana and thus continued to be selected by the model as beneficial low-cost resources.

A sensitivity was conducted on the near-term (2021-2023) selectable energy efficiency blocks. The optimization module in the Aurora model selected between 0.50% and 1.50%

energy efficiency, based on the modeling inputs and the scenario being optimized. A sensitivity analysis was performed to compare 1.25% of energy efficiency to the 0.75% energy efficiency selected in the Reference Case. The sensitivity showed that increasing the near-term energy efficiency to 1.25% from 0.75% only increased the 20-year portfolio cost (NPVRR) by 0.15%.

MISO is considering moving to a seasonal planning requirement. Accordingly, a sensitivity was conducted to determine the implications to the Reference Case portfolio of building to a summer peak vs. a winter peak and the resulting impact this would have on seasonal planning reserve margin requirements. Modeling a dynamic seasonal planning reserve margin requirement proved to be challenging and ultimately was not pursued, so the sensitivity focused on comparing a summer peak construct to a winter peak construct. Summer peak load is higher than winter peak load, but this difference in peak load is partially offset by a difference in seasonal unit capacity rating. The optimization routine in the Aurora model consistently selected for the maximum amount of solar available in the early years. However, the analysis showed that a constraint was necessary to prevent an overbuild of solar in this early timeframe. This is because the lower peak capacity accreditation for solar during the winter season meant that the winter peak demand was not met with solar that exceeded 1,150 MW. Accordingly, this required a limitation on the availability of solar to this level. The amount of solar in the early years was also limited by practical considerations around logistics and operational feasibility.

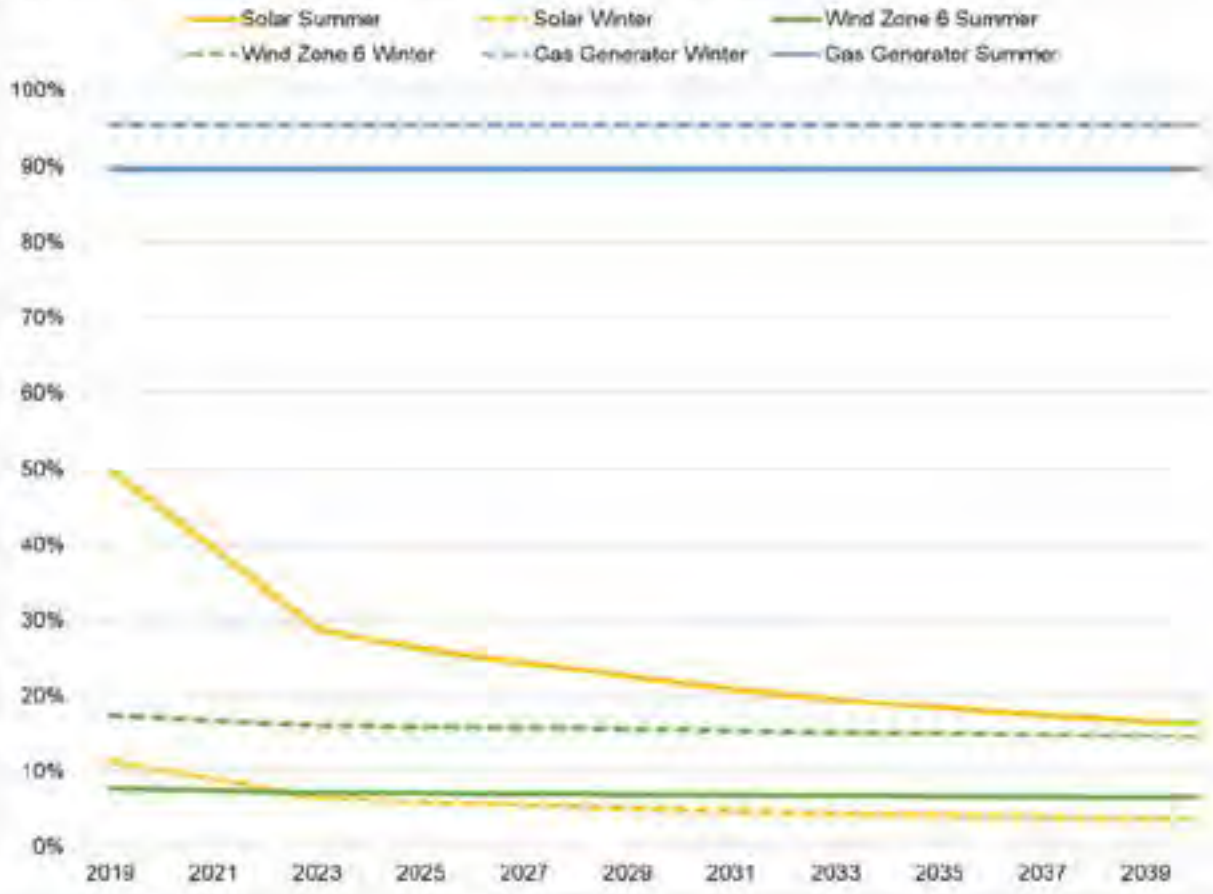
For this sensitivity, Vectren evaluated portfolios utilizing a reasonable summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation. All portfolios were required to meet both summer and winter peaks utilizing winter and summer accreditation. These forecasts were determined using MISO's ELCC accreditation formulas and MISO MTEP models for estimating renewable penetration levels. Applying similar methodology to MISO's current accreditation calculations, seasonal resource generation dispatching capabilities were accounted for. While using similar methodology to MISO's current solar would result in a 0% summer

accreditation, Vectren utilized a conservative assumption based on Stakeholder feedback of 11% UCAP accreditation (year 1). 11% was derived by providing some benefit to output at 9 am, which is one of the three non-consecutive highest winter load hours.

Figure 8-6 - Year 1 Seasonal Accreditation

Seasonal Capacity Accreditation	Year 1 (2019)	
	Summer	Winter
Solar	50%	11%
Wind MISO Zone 6	8%	17%
Gas Generator	~90%	~95%

Figure 8-7 - Seasonal UCAP Accreditation Forecast



The sensitivity demonstrated that Vectren should continue to plan for meeting its summer peak as the greater of the two seasonal constraints. When planning for and building to a winter peak, the Vectren system is built to meet the winter peak in all hours but is overbuilt to meet the summer peak in all hours. Based on this sensitivity analysis, each portfolio was designed and built to meet summer peak load and resulting planning reserve margin requirements.

8.2.3 STOCHASTIC (PROBABILISTIC) RISK ASSESSMENT

After selecting the 10 portfolios for further consideration and completion of the deterministic (Scenario based) risk assessment and sensitivities, the remaining step is to conduct the 200 iteration or scenario risk assessment and complete the balanced scorecard, consider “other” relevant factors and select the preferred portfolio given all of that information.

A more comprehensive risk analysis, using 200 iterations or scenarios, was utilized to provide a more comprehensive assessment of how the 10 portfolios performed under a range of conditions. As with any analysis, the risk analysis and the balanced scorecard that is developed from it, does not provide Vectren with an answer, but rather it is intended to provide insights into tradeoffs associated with a variety of portfolios over a range of future conditions.

The relevant information is provided in many of the metrics in the balanced scorecard. The benefit of conducting the stochastic risk assessment is that Vectren can get a clearer picture of the tradeoffs between least cost , the cost uncertainty (measured by the 95th percentile of cost outcomes over the planning horizon), the carbon equivalent profile of the portfolios and the percentage dependence on energy and capacity purchases and sales of the portfolios based on the probabilistic range of potential outcomes. After this comparison there is also a discussion of other factors that must be considered, like diversity, flexibility and optionality to adapt to conditions that might cause uneconomic assets.

A summary of how the ten candidate portfolios performed against each of the above metrics is provided in the table below:

Figure 8-8 - IRP Portfolio Balanced Scorecard Color-Coded Comparison (NPVRR in millions of dollars)

	Stochastic Mean 20-Year NPVRR	95th Percentile Value of NPVRR	% Reduction of CO2e (2019-2039)	Purchases as a % of Generation	Sales as a % of Generation	Purchases as a % of Peak Demand	Sales as a % of Peak Demand
Reference Case	$2,538	$2,921	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,914	$3,308	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,691	$3,094	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion+CCGT	$2,875	$3,269	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,677	$3,048	61.5%	19.2%	20.4%	1.2%	0.3%
Bridge ABB1+ABB2 Conversion	$2,836	$3,215	61.5%	18.5%	27.6%	4.0%	5.6%
Diverse Small CCGT	$2,681	$3,072	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,528	$2,927	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,614	$3,003	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,592	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

A color-coded comparison (conducted automatically by the spreadsheet) of the balanced scorecard is shown above in Figure 8-8. Green indicates scoring well relative to its peers in a metric and red indicates scoring poorly relative to its peers. The color scheme is purely for illustrative purposes to show where differences between the best performing portfolio and the worst performing for that attribute is displayed.

The Mean of the Net Present Value is clearly one of the most important attributes, as it was the basis on which each of the portfolios were selected in the first place. Under both reference case conditions and also considering the mean of the distribution, the Renewables Peak Gas Portfolio, which retired Culley 3 early, was the lowest cost Portfolio but by less than half of one percent relative to the reference portfolio. Since Culley provides greater reliability, resilience and diversity to the portfolio and the flexibility to retire the plant early, Vectren did not consider this to be a significant difference.

The next two lowest cost portfolios were the Reference portfolio and the High Technology portfolios whose NPVRRs were within two percent of each other. Once again, Vectren

did not consider portfolios within two percentage points on both the mean of the distribution and the 95th percentile (representing cost uncertainty risk) to be significant enough to differentiate these two options on the basis of cost.

The Costs and 95th percentile of the Business As Usual Portfolio and two of the Bridge solutions (the Bridge ABB1 and ABB2 and the Bridge ABB1 plus CC) were well above 10 percent higher than the Reference Mean and 95th percentile solutions, so they were eliminated from further consideration on the basis of cost.

SECTION 9
IRP PREFERRED PORTFOLIO

9.1 PREFERRED PORTFOLIO RECOMMENDATION

Based upon several factors, Vectren's preferred portfolio is the High Technology Portfolio.

9.1.1 Description of the Preferred Portfolio

The new and existing supply and demand resources in the preferred portfolio (High Technology) include 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage[43]) and two new 236.6 MW CT units selected in 2024 and 2025, all of which replace the A B Brown 1 and 2, F B Culley 2 and Warrick 4 coal units when they retire or exit at the end of 2023. An additional 50 MW of storage is selected in the final year of the forecast for reserve margin purposes. Approximately 1.25% of energy efficiency blocks are included in the near-term time period (2021-2023), approximately 0.75% of energy efficiency blocks are selected in the mid-term (2024-2026) and approximately 0.50% of energy efficiency blocks are selected in the long-term (2027-2039). In addition, low Income energy efficiency is included in all periods. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039, while a Direct Load Control (DLC) program called Summer Cycler is transitioned to Wi-Fi thermostats over time. F B Culley 3 operations continue throughout the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases.

The preferred portfolio (High Technology) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The preferred portfolio (High Technology) was within 2.5 percent of the lowest cost portfolio and ranked 2 out of 10 (second best) in the 95th percentile cost risk metric. It did not over-rely on either purchases or sales of energy or capacity.

[43] Modeled as 3-hour battery. Equates to a ~90MWs for 4-hours

Importantly it provides the flexibility and optionality to move quickly to a more renewable future as the reliability of the MISO system adapts to higher levels of renewables across the system. By having the option to retire Culley, Vectren can move when needed to a portfolio more like the Renewable + Flexible Gas portfolio.

Another distinguishing factor in this portfolio is the selection of two CTs. The two CT's provide the following benefits:

- They eliminate the reliance on for capacity in the near term at a time when MISO suggests that there could be shortages
- They provide the capability to convert to a combined cycle if needed for reliability in the future
- They are primarily used for peaking and fast ramping, which provides more room for renewables in the future
- They are relatively inexpensive to build and save customers ~$50M in design and construction costs by building two units at the same time vs. waiting to build the 2nd
- Maintains interconnection rights should units be built at the Brown site, shielding customers from future transmission upgrade costs

The High Technology portfolio provides a number of additional benefits to Vectren customers and other stakeholders, including that it:

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is a low cost portfolio (within 2.5% of the lowest cost portfolio and 2.2% of the Reference Case (the latter of which is the more appropriate comparison due to the same assumption that F B Culley 3 is operational through the forecast period)
- Leads to a lower carbon future – Achieves almost 60 percent reduction in life cycle carbon emissions (CO_2e) during the period 2019-2039 and achieves a nearly 75%

reduction in CO_2 (base year 2005) by 2035 with the flexibility to achieve even more if needed

- Brings a significant volume of renewables into the portfolio beginning in 2022. Renewable resources and ongoing energy efficiency account for more than 72% of total installed capacity by 2024 (more than 42% in terms of UCAP)
- Provides dispatchable generation that enhances opportunities for economic development and wholesale sales without overexposure to market risk relative to other candidate portfolios, which lowers customer bills
- Provides fast ramping generation to help manage the intermittency of renewables, including extended periods of complete cloud cover that can reduce solar generation by up to 75%[44]
- Avoids reliance on a single fuel and provides a balanced and diversified mix of renewables, DSM, gas and coal.
- Provides the optionality of converting to a combined cycle unit in the future if market, regulatory, technological and/or economic conditions necessitate
- Reduces dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future
- Takes advantage of tax incentives for new solar power plants and for new wind resources

9.1.2 Affordability

Affordability is a key objective in the balanced scorecard and that is measured as part of the stochastic analysis. The measure for affordability is the 20-year Net Present Value of Revenue Requirements (NPVRR), which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is run in the dispatch model under varying market

[44] NASA, Cloud Cover and Solar Irradiation, (source: https://scool.larc.nasa.gov/lesson_plans/CloudCoverSolarRadiation.pdf) using the formula shown below:

$$P = 990\,(1-0.75F^3) \quad \text{watts/m}^2$$

where F is the fraction of sky cloud cover on a scale from 0.0 (0% no clouds) to 1.0 (100% complete coverage).

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 revenue and capacity market purchases costs. Each annual cost category is then summed into a total portfolio cost and discounted by Vectren's weighted average cost of capital of 7.71% to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be in order to recuperate 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 (High Technology) was determined to be a cost portfolio across the 10 candidate portfolios, with a 20-year NPVRR of $2,592 million. This NPVRR is only 2.16% higher than the Reference Portfolio, a difference of less than $55 million over 20 years on a net present value basis. The preferred portfolio (High Technology) is 11% less expensive than the Business as Usual to 2039 portfolio (the most expensive portfolio in this objective category), which provides a savings of nearly $322 million over 20 years on a net present value basis.

9.1.3 Cost Uncertainty Risk Minimization

The Cost Uncertainty Minimization objective is measured in a similar way to the Affordability objective, using the 20-year NPVRR values from the stochastic analysis. However, this objective provides a measure of the 95th percentile of the NPVRR to determine an upper boundary (or worst-case perspective) of portfolio costs across the 200 stochastic iterations. The Price Risk Minimization objective can be interpreted as follows: There is a 95% chance that total portfolio costs as measured by the 20-year NPVRR will be at or below this measure. In this way, the risk that total portfolio costs over 20 years can be measured, allowing for the selection of a portfolio that minimizes this risk. This in turn minimizes the risk that rates (prices) will be higher than the expected, where expected rates (costs) come from the Affordability objective.

The preferred portfolio (High Technology) performed well in the Price Risk Minimization category. The 95th percentile of the 20-year NPVRR was determined to be $2,978 million, which is only 1.95% higher ($57 million) as compared to the Reference Portfolio 95th percentile of the 20-year NPVRR. For this same objective, the preferred portfolio (High Technology) was found to be $330 million less than the Business as Usual to 2039 portfolio, which is also the most expensive portfolio in this objective category. Accordingly, the preferred portfolio (High Technology) is shown to have a low level of price risk relative to its own expected NPVRR as well as relative to the least cost portfolio, the most expensive portfolio and all other candidate portfolios.

9.1.4 Environmental Emission Minimization

The Environmental Emission Minimization objective is determined from the stochastic analysis and is measured as the life cycle greenhouse gas emissions reductions during the study period of 2019-2039. Life cycle greenhouse gas emissions are also known as CO_2-equivalent or CO_2e emissions. The development of this measure is described in detail in Section 2.3.2.3 and takes into account the CO_2e emissions associated with the annual MWh of generation over 20 years from each technology type in the candidate portfolio. CO_2e emissions are also calculated for any energy imports from MISO, using a representative future capacity mix by resource that is associated with the 2033 Accelerated Fleet Change mix from MISO's MTEP 2019 document.

The preferred portfolio (High Technology) performed relatively well in the Environmental Risk Minimization objective, reducing annual CO_2e emissions by more than 4 million tons over the 2019-2039 study period (where 2019 CO_2e emissions are more than 6.7 million). This represents a nearly 60% decrease over 20 years and a larger decrease than is shown in the Reference Case, which is determined to have a 58% decrease. Relative to the other candidate portfolios, the preferred portfolio (High Technology) shows a CO_2e emissions reduction figure that is in the middle of the pack, with a smaller reduction than the renewables focused portfolios but a greater reduction than the Business as Usual to 2039 portfolio, which only reduces CO_2e emissions by 35% over the 20 year study period.

However, there is flexibility built into this portfolio to achieve further reductions if coal is no longer needed for reliability and resilience purposes and if the economics of renewables becomes even more compelling.

While not part of the balanced scorecard, the preferred portfolio (High Technology) was found to reduce (actual not life cycle) CO_2 emissions by 74.5% compared to the baseline year of 2005. This represents an annual reduction of nearly 7.2 million tons of CO_2 from the baseline of 9.6 million tons of CO_2. This figure is more than twice the reduction of CO_2 emissions that is shown in the Business as Usual to 2039 portfolio and slightly greater than the Reference Case CO_2 emissions reduction.

9.1.5 Market Risk Minimization

The Market Risk Minimization objective is applicable to both energy market risk and capacity market 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 Vectren 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 Vectren fleet. Conversely, 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 Vectren fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be lower than the cost of capacity in the Vectren fleet, meaning the portfolio is overbuilt. In either case, heavy reliance on market sales could lead to inflated valuation of a portfolio.

The preferred portfolio (High Technology) performed relatively well in terms of energy market risk minimization, averaging 16.7% energy purchases as a percentage of generation. This figure is in the middle of the 10 candidate portfolios, slightly less than the Reference Case (16.8%) and much less than the Renewables 2030 portfolio (26.1%) but

greater than the Diverse Small CCGT portfolio (6.4%). The preferred portfolio (High Technology) ranked third best in terms of energy sales with a figure of 26.9% as a percentage of generation, only slightly more than the best performing portfolio in this category (the Bridge ABB1 Conversion portfolio at 26.4%) and much less than the Business as Usual to 2039 portfolio at 36.5%. When looking at net energy sales, the preferred portfolio (High Technology) demonstrates a figure of 10.2%, which is within the threshold criteria of 15% that was discussed during a stakeholder meeting. The 15% level is based on a reasonable level of net sales that would not overexpose Vectren to energy market risks, in the estimation of Vectren's market consultants. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of energy market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

The preferred portfolio (High Technology) performed relatively well in terms of capacity market risk minimization, demonstrating a figure of only 0.4% capacity market purchases as a percentage of peak load. This figure is the second lowest of the 10 candidate portfolios, only slightly more than the Business as Usual to 2039 portfolio with 0.1% capacity market purchases. The selection of two CT's reduces the need for significant levels of capacity purchases throughout the planning horizon, which is important since MISO is still evaluating the issues of reliability and resilience of the grid as renewables become a larger share of the region's portfolio. The preferred portfolio (High Technology) was determined to have capacity market sales of 4.6% as a percentage of peak load, which is in the middle of the 10 candidate portfolios and much less than the 11.1% capacity market sales in the Business as Usual to 2039 portfolio but greater than the Reference Case portfolio with 1.2% capacity market sales. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of capacity market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

9.1.6 Other Considerations

9.1.6.1 Future Flexibility

The preferred portfolio (High Technology) was originally selected using a least-cost capacity expansion under the market conditions for the High Technology alternative scenario, but was then dispatched under the same Reference Case market conditions in the deterministic analysis and then evaluated using the same range of market conditions as all other candidate portfolios in the stochastic analysis.

These alternative market conditions for the optimization included lower CO_2 costs, higher load, lower fuel prices and lower renewable and EE costs, all relative to the Reference Case. Each of the market conditions are plausible alternatives to the most expected path in the Reference Case. For example, there is not yet a political consensus on whether and how to implement a national tax on carbon, which provides some justification for a lower CO_2 price relative to the Reference Case. The load growth from electric vehicles and the electrification of several sectors (buildings, industry, heavy transport) represent substantially more upside potential than the savings and downside potential that could come from demand side management and energy efficiency, which provides some justification for a higher load outlook. Coal markets experienced a downturn in 2020 due to COVID-19-induced demand reduction, from which (together with many other downward market pressures) it will be difficult to recover in the long-term. Gas prices have come down significantly in the last decade due to technology improvements and an expanding list of reserves from new discoveries, which could continue over the next two decades, while a more aggressive move to renewables could undercut demand for natural gas in the power sector, all of which would put increased downward pressure on gas prices. Finally, an aggressive expansion of renewables relative to the Reference Case could put downward pressure on capital costs, in much the same way that the broad deployment of personal computers led to lower prices due to economies of scale.

The preferred portfolio (High Technology) performed well across the various metrics in the balanced scorecard in both the Reference Case (expected) market conditions and (by

definition) the High Technology market conditions, which are only slightly less probable than the Reference Case market conditions (in the estimation of Vectren's market consultants). It also performed well relative to the other candidate portfolios when dispatched in the 80% Reduction by 2050, High Regulation and Low Regulation alternative market conditions. In all of the scenario-based alternative market conditions as well as the stochastic analysis with 200 iterations of varying market conditions, the preferred portfolio (High Technology) did not show any solar energy curtailments and only showed an expected average value of 0.02% wind energy curtailment in five years during the 2019-2039 study period. Thus, the preferred portfolio (High Technology) demonstrated the flexibility to adapt to a wide range of changing market conditions.

9.1.6.2 Uneconomic Asset Risk

One of the factors that Vectren considered was the potential for assets becoming uneconomic over the planning horizon. This was a concern raised by stakeholders about the 2016 IRP when Vectren recommended building a large combined cycle plant which benefited from a significant reliance on projected energy sales to support its economics. One of the concerns expressed was whether the plant could become uneconomic if renewables and storage were to achieve rapid cost declines such that the combined cycle dispatch would be adversely impacted and thus unable to cover its costs.

An analysis was performed to determine whether this was a significant risk with the mix of assets proposed. A metric was created to assess the risk. An asset was determined to be uneconomic during one of the iterations of the risk analysis if for three years in succession, revenues would not recover costs. The analysis performed determined that the assets most at risk were the assets that were selected to provide capacity to support the renewable resources, mainly the CT's and storage. The reason is that especially early in the planning horizon, capacity has often been priced below CONE. While MISO has indicated a concern that shortages could well occur in MISO over the next several years, this was not reflected in many of the iterations. Ultimately the value of this metric is questionable. Portfolios with plants with large energy revenues (coal and combined cycle)

performed better than combustion turbines, even though they require a larger capital spend than CTs.

If Vectren were to mitigate this conclusion it would rely heavily on purchases in the capacity market rather than build CT's and storage. Vectren did not believe this was appropriate in this uncertain environment and chose a path with CT's and storage rather than relying heavily on the capacity market.

9.1.6.3 Reliability

Reliability can be measured in different ways, but one common metric is whether the portfolio experiences any unserved energy. The preferred portfolio (High Technology) was dispatched in the Aurora model using Reference Case inputs as well as the inputs from the four alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load and capital costs. In each of these deterministic dispatch runs, the preferred portfolio (High Technology) was not found to have any hours of unserved energy. Accordingly, although Reliability is not an explicit objective in the balanced scorecard, the preferred portfolio (High Technology) was found to provide reliable service in meeting Vectren's expected load requirements over the 20-year study period.

Two highly dispatchable combustion turbines (460 MW) support a high penetration of renewables, ensuring reliability and provide a hedge against both the energy and capacity markets. They help provide customers assurance of reliable service in many ways.

- Thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind
- Two CT's provide better support than one. Better coverage should a unit go down to provide a hedge against high energy prices and provide system support when issues arise

- Two CT's keeps existing interconnection rights, which shields customers from potential transmission upgrade costs in the future should Vectren have to re-enter the MISO Queue (a three-year process).
- Two CT's provide fast start (10 min) & more fast ramping capability (80 MW/minute vs 40 MW/minute) to help support for intermittent solar and allows for a smooth transition into a renewables future locally and regionally as the MISO system adapts to higher levels of renewables across the system
- Two CT's provide a high degree of flexibility in the future

9.1.6.4 Operational Flexibility

The preferred portfolio (High Technology) includes a significant amount of new variable energy resources (VER) (wind and solar) balanced by 176 MW of battery storage (50 MW of which enters late in the forecast) and two 236.6 MW natural gas peaking units. The battery storage and CT units 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 CT's and battery storage perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Given the level of VER in the preferred portfolio (High Technology) (approximately 1,500 MW) together with the fast-ramping capabilities of the CT's and battery storage, this portfolio is expected to meet all operational flexibility requirements.

Natural gas peaking combustion turbines (CT) respond quickly to changing operational requirements, since there is no water to heat on a percentage of capacity per minute basis (as compared to a combined cycle unit). CT's are simple to operate, requiring few staff and resources to run properly and to maintain (typically under a long-term service agreement or LTSA) and often they can be started remotely. CT's can also be black started, offering an additional degree of increased resiliency and operational flexibility.

Given the high volume of intermittent renewable generation in the preferred portfolio Vectren feels it's critical to have an adequate amount of dispatchable generation to meet its obligation to ensure reliable service is provided to Vectren customers throughout the different seasons of the year as well as all 24 hours of the day. Vectren'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.

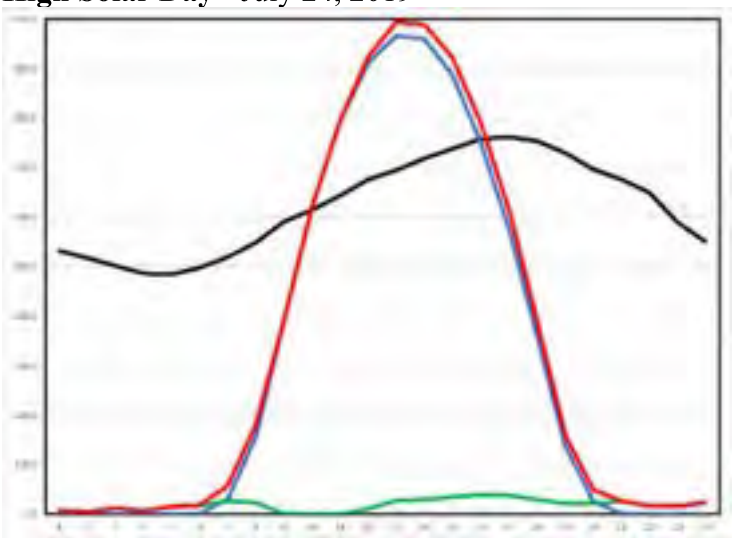
9.1.6.4.1 Vectren Seasonal and Daily Experience with Solar and Wind Production

The figures 9.1-9.4[45] below are actual seasonal days during 2019 and 2020 that show hour by hour customer demand and how 1,000 MW's of solar capacity and 380 MW's of wind capacity would have met customer demand if the solar and wind capacity factors were the same as what was realized from Vectren's current solar fields and wind purchase power agreements. High, typical and low solar production days were chosen for each season to show the large variation in levels that can be experienced daily during each season. Also, note the large drop off in production in the evening hours after the sun goes down. The additional energy required to serve Vectren customer demand would need to be purchased from the market or supplied by Vectren owned dispatchable generation sources. Local generation ensures more reliable energy and capacity with less risk of additional congestion charges associated with importing energy.

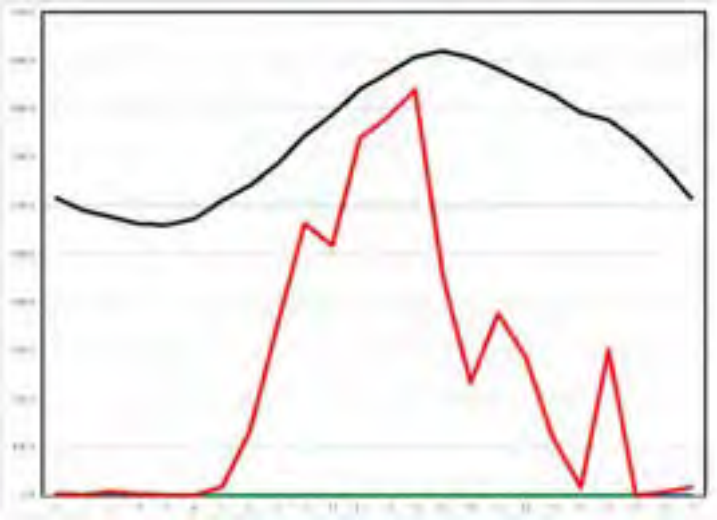
[45] **Black – System Load, Green – Wind, Blue – Solar, Red – Wind + Solar Used 1000 MW solar (scaled up from existing solar), 380MW wind (scaled up from existing 80MW). All data in 1-hour average increments, charts range from 0 to 1,000 MW except on high solar days in December (1,200MW) and March (1,400MW)**

Figure 9-1 - Summer Production and Vectren Demand:

High Solar Day - July 24, 2019



Typical Solar Day - August 9, 2019



Low Solar Day - July 15, 2019

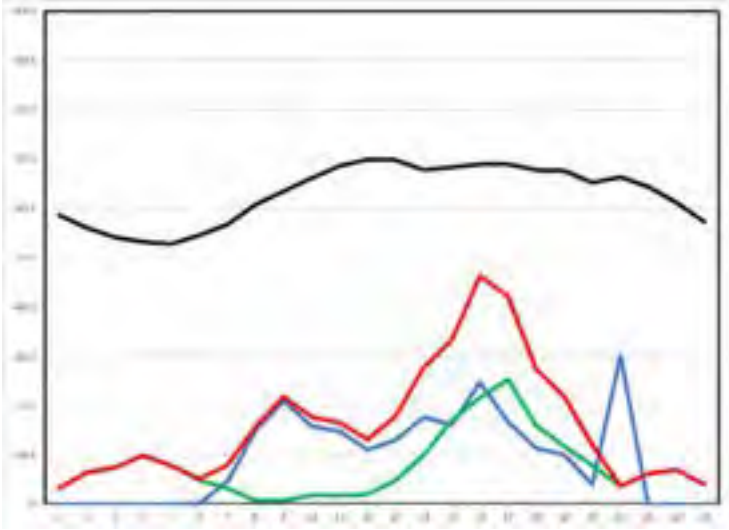
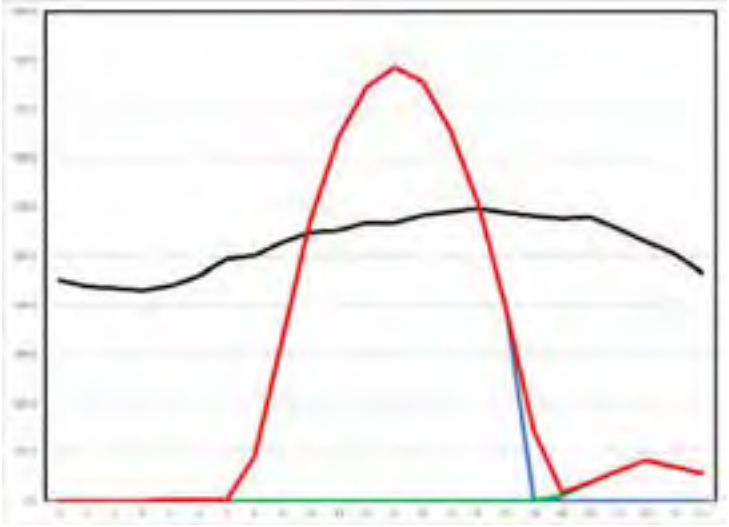
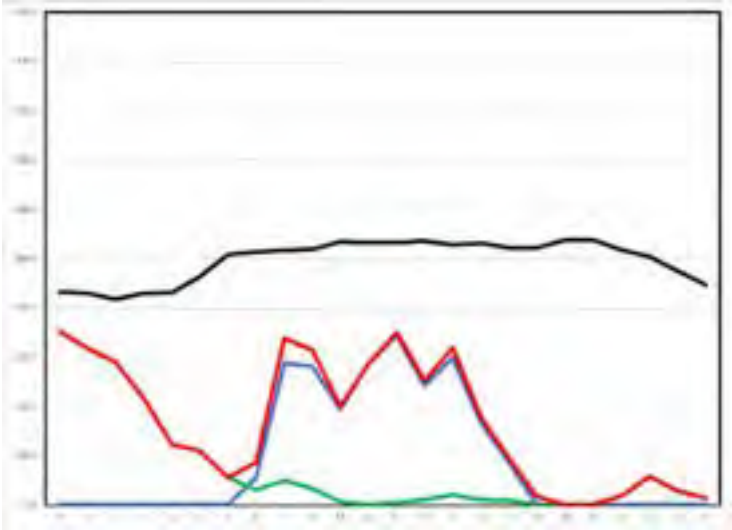


Figure 9-2 – Fall Production and Vectren Demand:

High Solar Day – October 8, 2019



Typical Solar Day – October 18, 2019



L**ow Solar Day** – October 25, 2019

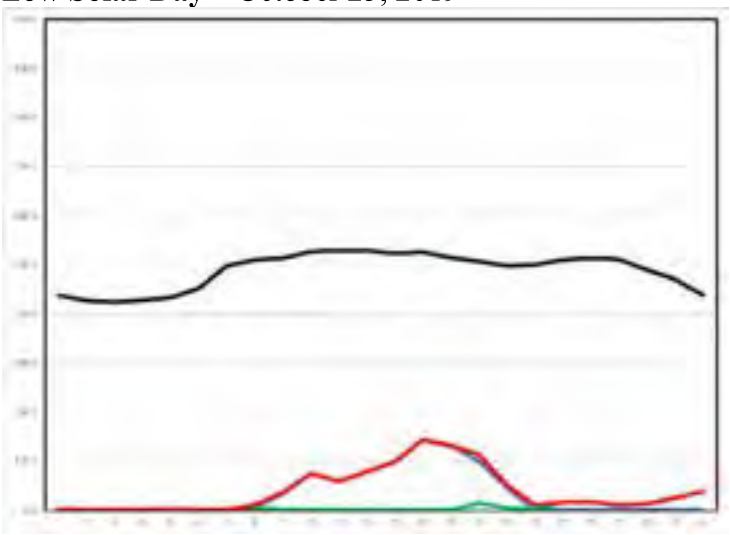
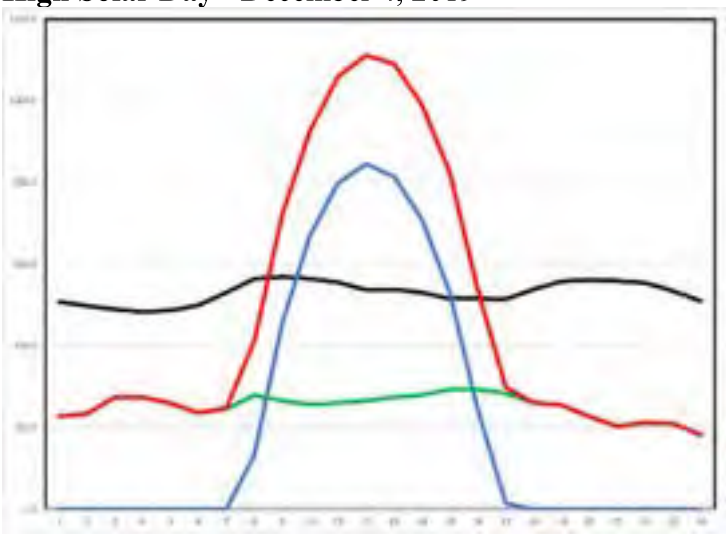
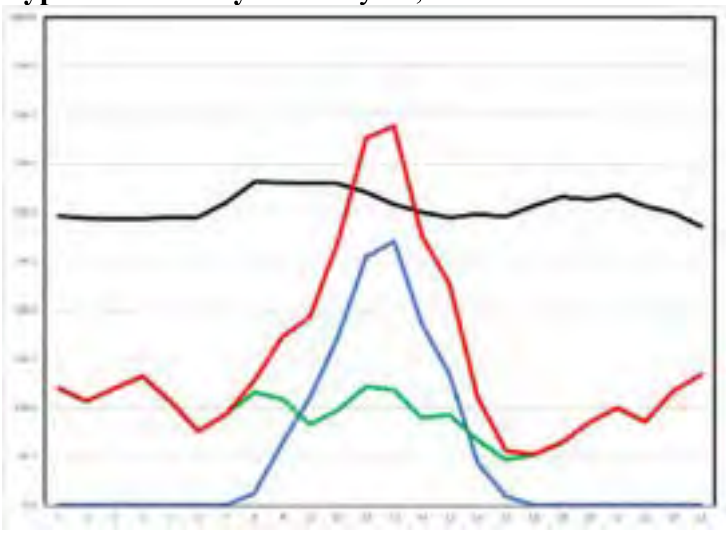


Figure 9-3 - Winter Production and Vectren Demand:

High Solar Day - December 4, 2019



Typical Solar Day - January 22, 2020



Low Solar Day - December 16, 2019

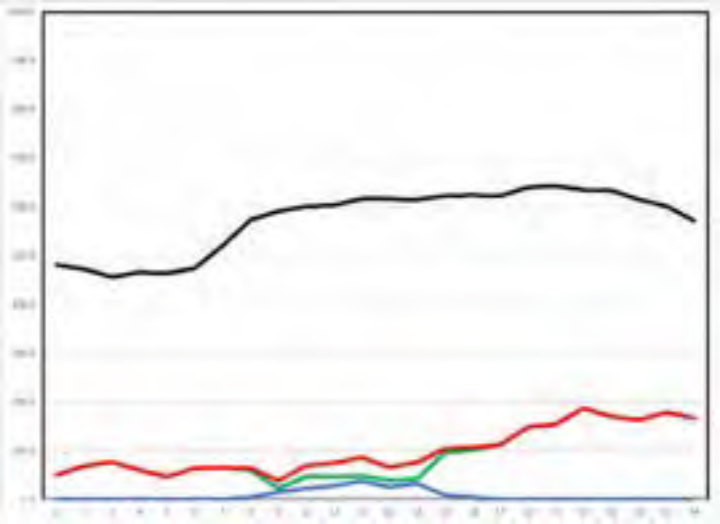
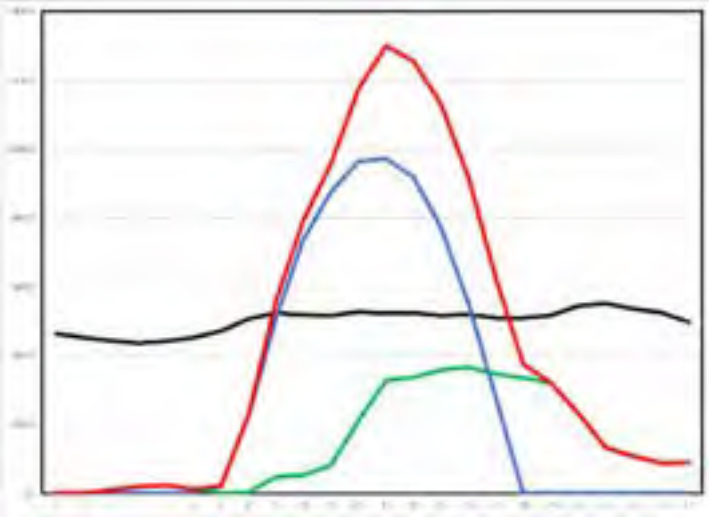
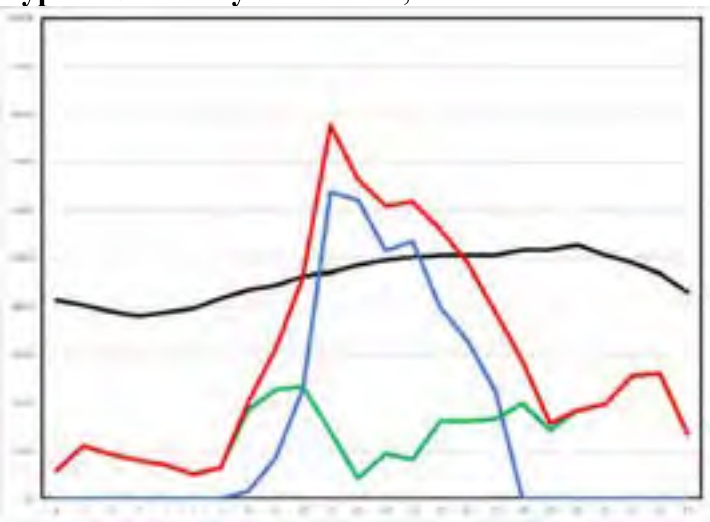


Figure 9-4 - Spring Production and Vectren Demand:

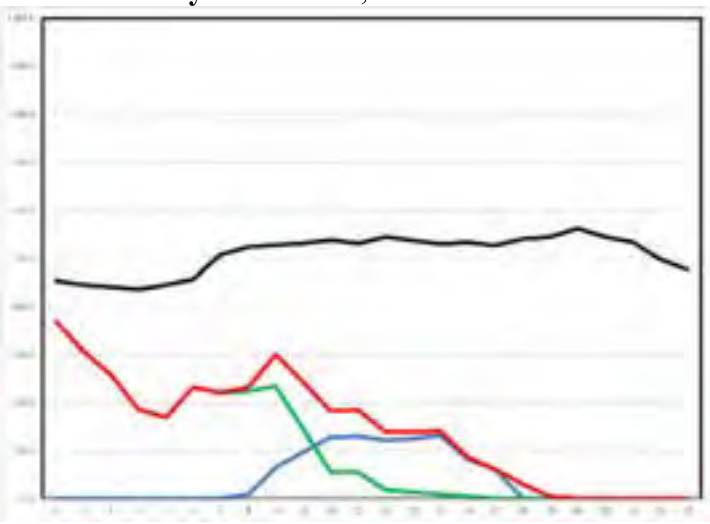
High Solar Day – March 3, 2020



Typical Solar Day – March 27, 2020



Low Solar Day – March 10, 2020



9.1.6.4.2 Vectren Experience with Solar Hourly and Daily Intermittency

The Figures above (9.1-9.4) represent an average hourly output or artificial smoothing of production across each hour of the day. There are days when there are large fluctuations in output over short periods of time due to changes in cloud cover or periodic gusts of wind. The figures below (9.5 and 9.6) show actual variation in output over a twenty-four-hour period and a one-hour period. These rapid fluctuations in output while working to

meet constantly changing customer demand require a robust transmission and distribution system to import large amount of power quickly as well as dispatchable resources that can ramp output up and down quickly. It should be noted that as other utilities retire coal resources and install more intermittent generation it will become more important to have locally placed fast reacting dispatchable resources to ensure reliable service is delivered to industrial, commercial and residential customers.

Figure 9-5 – 24 Hour Solar Chart

Sept. 2, 2019 - 12:00 to 13:00

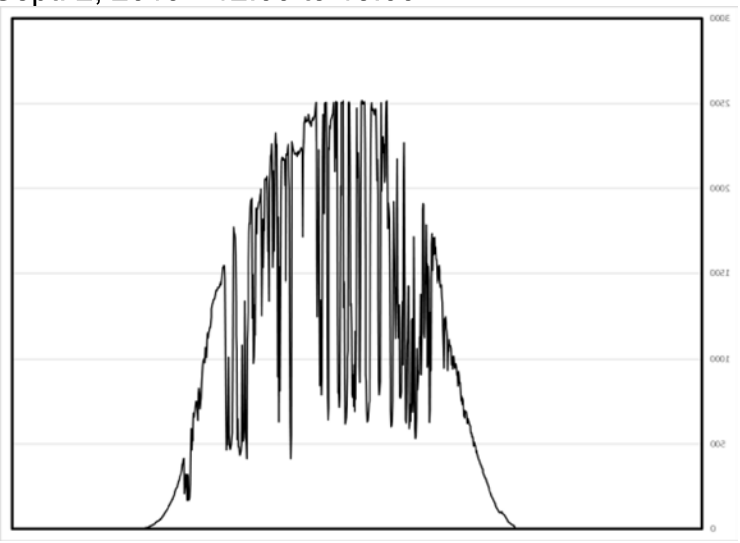
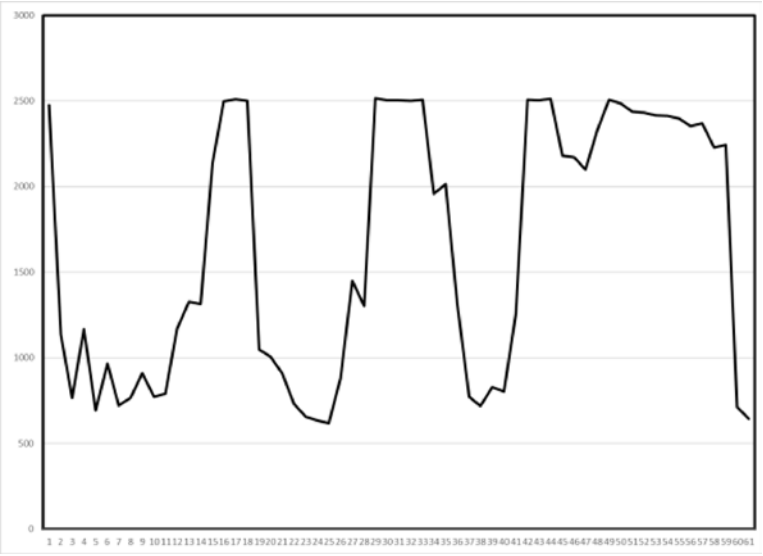


Figure 9-6 – 1-Hour Solar Production – September 2, 2019



Figures 9.5-9.6 aren't representative of every day throughout the year as there will be days when solar and wind production are more consistent; however, Vectren has an obligation to ensure customer demand is met by supplying reliable energy throughout every minute of every day of the year. Local fast start and fast reacting dispatchable resources will still be required to meet customer demand on days like Vectren experienced on September 2, 2019 as well as the evening hours after the sun goes down. Battery storage systems can meet a portion of this need; however, they are limited by discharge times as well as charge/discharge cycles, whereas CT's provide more long duration support.

Each unit will have the ability to start and be synchronized to the grid producing energy in approximately 10 minutes. This is important when relying on a large portfolio of renewable capacity. The CT's may be required to start and provide reliable energy for customers several times throughout the year when renewable energy is operating at reduced capacity due to cloud cover or a lack of wind. It's likely there may be times when the CT's are started and stopped more than one time daily.

Once placed in service, the quick ramping ability of a CT, at approximately 40MW/minute, will help meet customer needs when demand changes or renewable energy supplies quickly dip then return as cloud cover rolls over various solar arrays and wind fluctuates in areas where wind farms are built. Having two new CT's will provide the ability to ramp or adjust output by up to 80MW/minute to help supplement the import capability of the grid. In addition, having two CT's will provide flexibility as only one or both can be started as needed. Due to environmental restrictions, each CT will have a minimum output of approximately 80MW's. With one in service, the output can range from 80-220MW's. With both units in service, the output can range from 160-440MW's providing the operational flexibility to meet the needs of customers.

Of the gas fired generation options explored, the CT's were chosen due to the balance of low capital cost, efficiency and operational flexibility. Given the quantitative objectives in the balanced scorecard that includes; (a) minimizing the cost to the customer, (b) reducing emissions and (c) not relying heavily on the energy or capacity market as well as the qualitative objective such as diversity and properly supporting a large portfolio of renewable resources the CT's were chosen as an important resource in the preferred portfolio.

Lastly, the preferred portfolio with two CT's provides future flexibility to increase capacity and provide lower cost energy to Vectren customers by adding a steam cycle to one or both CT's. A steam cycle could be placed on one or both CT's to create a Combined Cycle Gas Turbine (CCGT) to capture waste heat to be turned into energy. This would lower the cost/MWh by increasing the efficiency of a CT by 30-35%. This could be accomplished if the need arises as a result of load growth due to new industrial customers, if it were determined in a future IRP that Culley Unit 3 should be retired, or the need for more low cost energy arises due to higher than expected market energy prices.

9.1.6.5 Resource Diversity

Resource Diversity is not an explicit objective in the balanced scorecard but is nevertheless an important criterion for a well-balanced portfolio. Resource Diversity allows a portfolio to avoid being dependent on one type of fuel or technology, which can expose the fleet to 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. Resource Diversity also contributes indirectly to the other objectives discussed here, including operational flexibility, future flexibility and reliability. From this point of view, the preferred portfolio (High Technology) is reasonably diverse and well-balanced in terms of resources, with a mix of natural gas CTs, solar and wind resources, battery storage resources and a baseload coal unit.

9.1.6.6 Local Resources

Vectren prefers local resources for both capacity and energy needs. Local resources benefit Vectren customers by reducing cost risk and providing tax base, jobs and grid support for reliability. The All-Source RFP provided many attractive renewable resources in Vanderburgh, Posey, Warrick, Gibson and Spencer Counties, which Vectren is evaluating for procurement.

Local generation also 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. The chances of incurring these charges increases the further away energy must be delivered. 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.

Investing in local projects help produce tax base and jobs, which directly benefit the communities Vectren serves. Currently, Vectren generates tax revenues for primarily two counties, Posey and Warrick. The preferred portfolio will provide opportunities for continued investment in these counties with the potential to also provide tax base from generating resources in Vanderburgh, Gibson and Spencer counties. Communities where Vectren 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.

Local projects also help keep the system reliable. Vectren's preferred portfolio maintains a good balance between intermittent renewable generation and local, dispatchable generation that provides the system with voltage support and a physical hedge against instances of high market prices. This is particularly important for large, industrial customers that make up nearly half of Vectren load.

9.1.6.7 Transmission/Distribution

The preferred portfolio required the lowest number of transmission system network upgrades of all cases studied, except for the CCGT case. Although the number of network upgrades were lower than other cases, upgrades to the Vectren system import capability were identified. The upgrades identified are the replacement of three transformers for a total estimated cost of $11 million and were also required for the other non-CCGT cases studied.

The reliance on imports from the MISO market into Vectren's area led to voltage concerns for post contingent conditions due to insufficient reactive reserves. CT's provide mitigation to these issues and can be used for reactive (VAR) support in the MISO market. The all imports and all renewables cases studied presented voltage issues that could not be mitigated with existing facilities. These issues would require additional network upgrade projects to add reactive power support and could also potentially lead to the need for Vectren to make Reactive Power Payments to the MISO market to receive off-network support to maintain proper reactive power and voltage levels. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed. However, initial estimates for needed upgrades are estimated to be between $20 and $30 million to maintain reliability. This amount was not included in the NPVRR of this portfolio.

Studies were performed using the latest MISO generation interconnection system models and all renewable resources studied were assumed to be the projects already in the MISO queue and existing in the model. Additional study will be required on the preferred portfolio once specific renewable projects are identified and sited to determine any further impacts on the Vectren transmission and distribution electric system.

9.1.6.8 Economic Development

The preferred portfolio allows Vectren to provide solutions to assist with manufacturers' renewable and sustainable energy goals. Companies are setting these goals leading to a reduction in fossil fuels consistent with their sustainability strategies. If these companies cannot find a solution with their local utility partners, they may procure energy from other sources or make strategic decisions to relocate manufacturing load.

Renewable energy investments are important steps in facilitating the ability to provide Vectren customers with a portion of their energy requirements via renewable energy. With proper oversight and investment strategy renewable energy can be more efficient and cost-effective for many customers as compared to securing their own sources of energy which requires land and/or capital investments.

The communities in Vectren's service territory will benefit to the extent the addition of renewable energy supports growth among Vectren South's large customers or attracts new customers. The creation of additional jobs in the communities Vectren serves has a ripple effect on the local economy. Moreover, renewable energy projects will create construction jobs in the community and provides additional income for landowners, which also will benefit the local economy. Ultimately, renewable energy projects support the attraction and retention of large customers.

Although Vectren supports cost effective and reliable renewable energy projects, Vectren must maintain strategic planning in the event large industrial customers locate to SW Indiana and require baseload generation for production. Site selectors and large industrial power users are typically sophisticated and fully understand the requirements to apply, receive approval and execute generation buildout. Comprehensive generation planning inclusive of renewable energy and base load assets must be properly balanced to continue economic growth for our region.

For industrial customers to maintain their required voltage level, the Vectren 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 CT's in the preferred portfolio provide this needed reactive power support. Even when they are not dispatched normally, CT's are able to be started and brought online quickly if needed for Vectren system reliability. CT's also prevent Vectren from entering into Reactive Power Payments through the MISO market, which would impact Vectren customers' bills.

Importantly, the current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, Vectren must remain nimble and dynamic for prospective industrial customers and to be able to adapt to the potential need for CCGT build out. Vectren aggressively pursues manufacturing opportunities which has direct, indirect and induced economic benefits for the region and state of Indiana. Vectren's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunity for local residents at the same time raising state revenue and tax base. Additionally, large power users assist all Vectren customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

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 Vectren's ability to provide safe, reliable and cost-effective service. Vectren's generation strategy is an essential service for customers and the region's economic growth capability.

9.1.7 Fuel Inventory and Procurement Planning

It is impossible to perfectly predict price fluctuations in commodity prices such as coal and natural gas. Vectren uses coal contract strategies intended to even out short-term price fluctuations, such as locking in prices for various overlapping time horizons.

Normally these contract renewals are staggered in time in order to even out short-term price fluctuations. Coal suppliers and transportation providers generally require firm commitments on quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future flexible combustion turbines will utilize firm pipeline supply contracts.

SECTION 10
SHORT TERM ACTION PLAN

10.1 DIFFERENCES BETWEEN THE LAST SHORT-TERM ACTION PLAN FROM WHAT TRANSPIRED

Vectren pursued all the items listed in the 2016 IRP short-term action plan.

10.1.1 Generation Transition

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient large natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. Vectren pursued this plan through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved.

10.1.2 DSM

The 2016 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2018-2020 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on December 28, 2017 in Cause No. 44927. Consistent with the 2016 IRP, the framework for the 2018-2020 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

10.1.3 Solar Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which

is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December of 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

10.1.4 Environmental Permits for ELG/CCR

The bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

10.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

The short-term action plan describes the early steps to pursue the preferred portfolio, consistent with the objectives and risk perspectives listed in Section 2.3. Progress on the items listed below will be tracked and reported on in the next IRP. IRP estimates of each piece of the plan listed below can be found in Confidential Attachment 8.2 Aurora Input Model Files. Individual cost estimates can also be found in Section 6 Resource Options.

10.2.1 Procurement of Supply Side Resources

As described above, the preferred portfolio included 300 MWs of wind, 700-1,000 MWs of solar and two combustion turbines (~460 MWs) to replace approximately 730 MWs of coal fired generation. Vectren will continue to monitor developments with the State of Indiana's Energy Policy Task Force and the wholesale energy market for potential changes that could alter Vectren's plan. Regardless of the outcome, Vectren must continue to plan, as some portions are more certain than others.

Vectren plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) and Vectren's contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. In order to replace this generation, Vectren plans to acquire renewable generation in the next three years in order for Vectren's customers to benefit from expiring renewables tax incentives and, at a minimum, replace this portion of Vectren's coal fleet. This equates to approximately 700-1,000 MWs of capacity from solar generation towards the 2023/2024 and the 2024/2025 MISO planning years, partially dependent on expected solar penetration levels within MISO at that time and MISO resource accreditation.

To fill this need, Vectren plans to pursue attractive projects from its 2019 All-Source RFP consistent with the findings in the 2019/2020 IRP. The All Source RFP bids remain open until August 2020 and Vectren is in active discussions with short listed bidders for various renewables projects. Upon completion of expected negotiations Vectren plans to file a CPCN in 2020 so that its customers can receive low-cost solar energy from these projects before tax incentives are reduced. The remainder of Vectren's renewable need, including wind, solar and storage, could be filled through a second RFP. Affordable pricing will be important.

Vectren's plan allows for flexibility while awaiting clarity from the outcome of the Energy Policy Task Force and resource accreditation decisions from MISO; however, preliminary planning must begin for the potential replacement of the A.B. Brown coal plants with two combustion turbines most likely as it offers many benefits at the Brown site.

In order to accommodate the need for capacity by the end of 2023 for the 2024/2025 planning season, Vectren will begin design work and obtain updated cost estimates for equipment. Additionally, permits would need to be filed with FERC to bring gas to the Brown site, a continuation of work done in support of the 2016 plan. Vectren currently has approximately 500 MWs of interconnection rights for the Brown units at this brownfield site, which will allow Vectren to bypass the MISO Generation Interconnection Queue. Utilization of the Brown site helps to mitigate risk for Vectren customers, including reliance on the capacity market and risk of future transmission upgrades at different sites or later at the Brown site. A decision on CPCN timing will be made later this year.

10.2.2 DSM

Vectren has filed its 2021-2023 electric demand side management (DSM) plan in June of 2020. The 2021-2023 energy efficiency savings were guided by the 2019/2020 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC) and Vectren, will oversee the implementation of energy efficiency programs.

10.2.3 Solar Projects

Based on the Commission's 2019 approval, Vectren is currently constructing a 50 MW universal solar plant, interconnecting at transmission voltage (161kV) and is expected to be in service in the first quarter of 2021.

10.2.4 Culley 3

Based on the Commission's 2019 approval, Vectren is proceeding with the installation of the F.B. Culley Unit 3 mandated environmental compliance projects. The new pollution control equipment installations are in various stages of engineering and planning with the expected in-service dates meeting the defined timelines.

10.2.5 Ability to Finance the Preferred Portfolio

The Company and its parent corporations expect to have sufficient funds to finance the preferred portfolio, through a combination of internally generated cash flow from operations and external capital markets activity.

10.2.6 Continuous Improvement

Vectren takes continuous improvement seriously and works to ensure that improvement opportunities are evaluated and where appropriate implemented. This is done in several ways. First, Vectren participates in the Director's report process and listens to critiques of its IRPs from multiple stakeholders. Second, Vectren always conducts post IRP discussions with internal team members, as well as outside consultants to determine what can be done better in the next IRP. Third, Vectren participates in stakeholder meetings of other Indiana utilities and follows stakeholder feedback in those processes. Fourth, Vectren collects information on IRPs through news articles, conferences and Indiana's annual Contemporary Issues meeting. Finally, improvement opportunities come directly through the stakeholder process with formal and informal meetings, as they did throughout this IRP.

10.3 Implementation Schedule for the Preferred Resource Portfolio

Below is a general timeline for the Preferred Resource Portfolio, subject to change pending outcome of the Energy Policy Task Force.

Figure 10-1 – Implementation Schedule

Year	Quarter	Activity
2020	Q2	File for 2021-2023 DSM Plan File IRP
	Q3	Select Attractive Renewable Projects from All-Source RFP
	Q4	File CPCN for Renewable Projects Second RFP
2021	Q1	File CPCN for Combustion Turbines Results of 2nd RFP in
	Q2	
	Q3	Renewables CPCN Order
	Q4	Begin 2022 IRP Combustion Turbines CPCN Order
2022	Q1	
	Q2	
	Q3	
	Q4	File 2022 IRP

SECTION 11
TECHNICAL APPENDIX

11.1 CUSTOMER ENERGY NEEDS APPENDIX

11.1.1 Forecast Inputs

11.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database 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 exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

11.1.1.2 Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren 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.

11.1.1.3 Weather Data

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport, obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. 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 s 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 0.2% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.2% over the forecast period while CDD increased 0.5% per year through 2039. Figure 11.1 and Figure 11.2 show historical and forecasted monthly HDD and CDD.

Figure 11.1 – Heating Degree Days

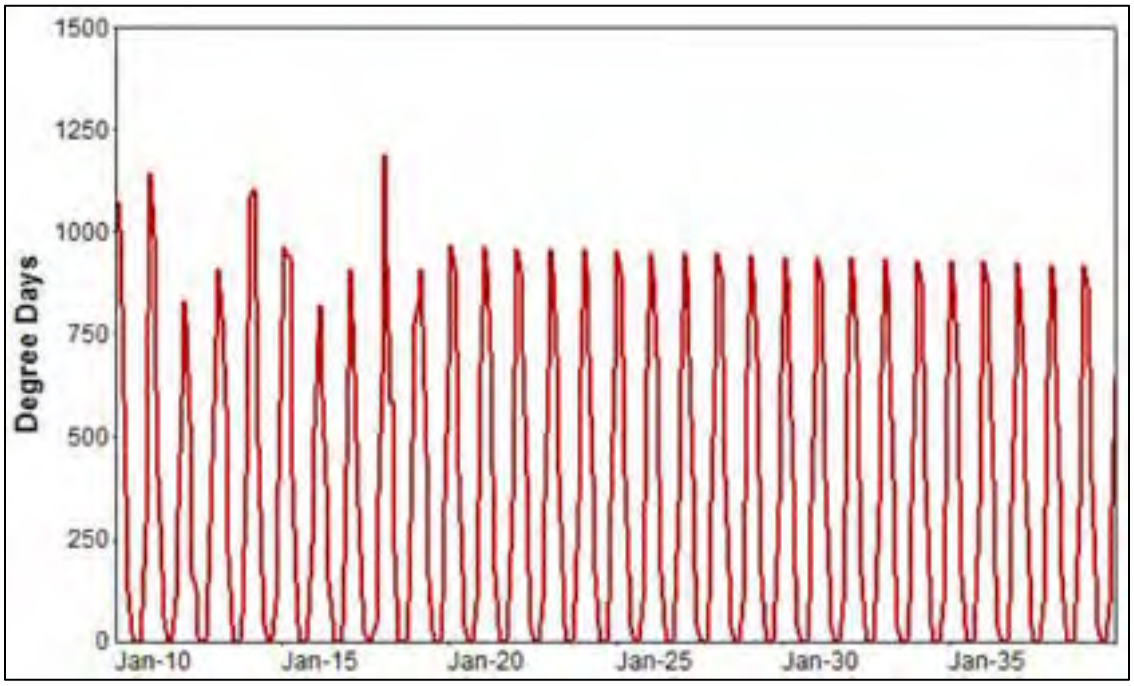
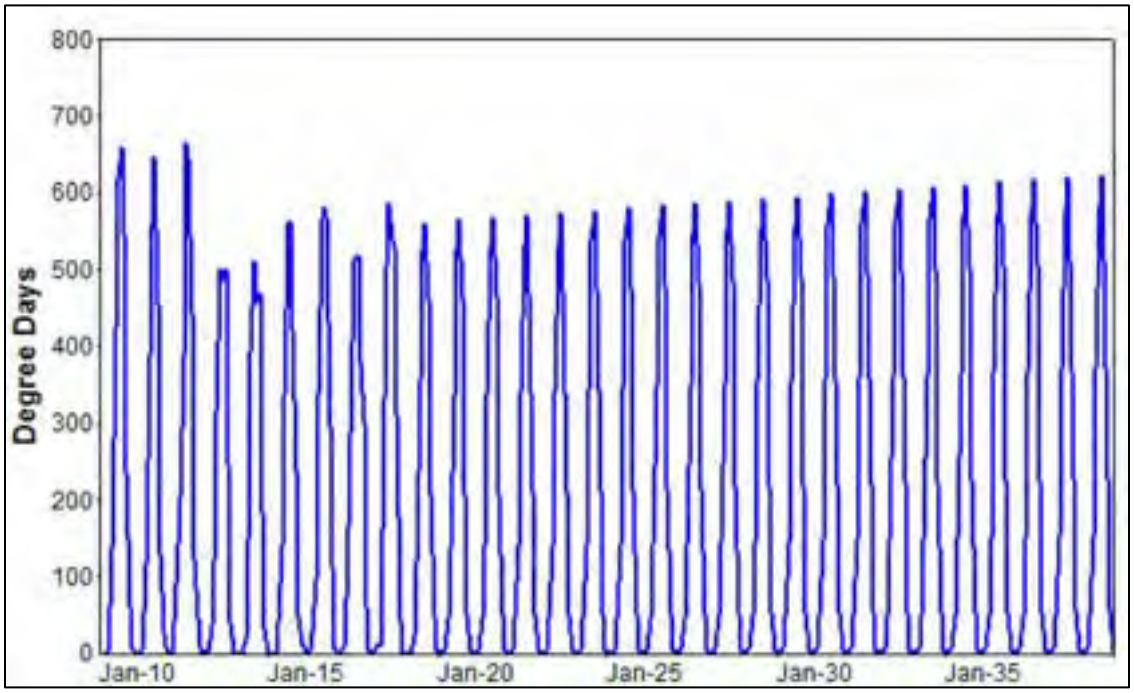


Figure 11.2 – Cooling Degree Days



11.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (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. Vectren conducted an Electric Baseline survey in the third quarter of 2016 of Vectren's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory. Appliance saturation surveys are conducted every 2-4 years, depending on need.

11.1.2 Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE (Statistically Adjusted End-Use) modeling framework. In addition to annually updating efficiency and saturations projections with the latest estimates from the EIA (Energy Information Administration) 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 Vectren forecast now also takes into account emerging technologies: customer distributed generation and electric vehicles. Customer owned photo-voltaic (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 adoption. The EIA uses a 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, Vectren continually stays up to date with load forecasting topics in a variety of ways. First, Vectren 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. Vectren forecasters 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. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares Vectren model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

11.1.3 Overview of Past Forecasts

The following tables outline the performance of Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2009-2018.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) 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 and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[46] and forecasted values for:

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

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

Figure 11.3 – Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	2016 Total Demand Forecast (MW)	WN Total Demand (MW)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,216					1,069	-13.7%				
2010	1,237	1,153				1,136	-8.9%	-1.5%			
2011	1,252	1,179				1,159	-8.0%	-1.7%			
2012	1,258	1,118	1,156			1,136	-10.7%	1.6%	-1.7%		
2013	1,265	1,115	1,156			1,144	-10.5%	2.6%	-1.0%		
2014	1,272	1,107	1,165			1,133	-12.3%	2.3%	-2.8%		
2015	1,281	1,100	1,164	1,155		1,113	-15.1%	1.1%	-4.6%	-3.8%	
2016	1,290	1,092	1,160	1,156		1,087	-18.7%	-0.5%	-6.7%	-6.3%	
2017	1,299	1,094	1,151	1,113	1,082	1,038	-25.2%	-5.4%	-11.0%	-7.2%	-4.3%
2018	1,308	1,093	1,145	1,109	1,086	1,006	-30.0%	-8.6%	-13.8%	-10.2%	-7.9%
Mean Absolute Error							15.3%	2.8%	5.9%	6.9%	6.1%

Figure 11.4 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	2016 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	6,090					5,365	-13.5%				
2010	6,230	5,306				5,701	-9.3%	6.9%			
2011	6,329	5,460				5,819	-8.8%	6.2%			
2012	6,369	5,456	5,837			5,718	-11.4%	4.6%	-2.1%		
2013	6,422	5,434	5,807			5,743	-11.8%	5.4%	-1.1%		
2014	6,476	5,403	5,803			5,797	-11.7%	6.8%	-0.1%		
2015	6,527	5,365	5,772	5,914		5,773	-13.1%	7.1%	0.0%	-2.4%	
2016	6,580	5,336	5,725	5,936		5,725	-14.9%	6.8%	0.0%	-3.7%	
2017	6,629	5,315	5,657	5,514	5,257	5,073	-30.7%	-4.8%	-11.5%	-8.7%	-3.6%
2018	6,680	5,292	5,590	5,503	5,290	5,139	-30.0%	-3.0%	-8.8%	-7.1%	-2.9%
Mean Absolute Error							15.5%	5.7%	3.4%	5.5%	3.3%

Figure 11.5 – Residential Energy (GWh)

Year	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	2016 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,595					1,512	-5.5%				
2010	1,620	1,467				1,483	-9.2%	1.1%			
2011	1,645	1,440				1,460	-12.7%	1.3%			
2012	1,663	1,421	1,462			1,437	-15.7%	1.1%	-1.7%		
2013	1,683	1,391	1,419			1,421	-18.4%	2.1%	0.1%		
2014	1,703	1,365	1,399			1,412	-20.6%	3.3%	0.9%		
2015	1,722	1,332	1,371	1,404		1,444	-19.2%	7.8%	5.1%	2.8%	
2016	1,742	1,304	1,340	1,394		1,416	-23.0%	7.9%	5.4%	1.5%	
2017	1,759	1,282	1,305	1,383	1,407	1,398	-25.8%	8.3%	6.7%	1.1%	-0.6%
2018	1,777	1,264	1,271	1,377	1,395	1,375	-29.2%	8.1%	7.6%	-0.2%	-1.5%
Mean Absolute Error							17.9%	4.6%	3.9%	1.4%	1.1%

Figure 11.6 – Commercial (GS) Energy (GWh)

Year	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	2016 Comm. IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff
2009	1,384					1,319	-4.9%				
2010	1,404	1,275				1,314	-6.8%	3.0%			
2011	1,426	1,284				1,307	-9.1%	1.8%			
2012	1,438	1,296	1,375			1,283	-12.1%	-1.0%	-7.2%		
2013	1,455	1,304	1,383			1,294	-12.4%	-0.7%	-6.9%		
2014	1,472	1,307	1,399			1,312	-12.2%	0.4%	-6.6%		
2015	1,490	1,306	1,402	1,364		1,321	-12.8%	1.1%	-6.2%	1.3%	
2016	1,507	1,306	1,398	1,320		1,281	-17.7%	-1.9%	-9.1%	-3.0%	
2017	1,525	1,309	1,384	1,315	1,315	1,278	-19.3%	-2.4%	-8.3%	-2.9%	-2.9%
2018	1,544	1,311	1,373	1,311	1,324	1,235	-25.0%	-6.1%	-11.1%	-6.1%	-7.2%
Mean Absolute Error							13.2%	2.0%	7.9%	3.3%	5.1%

Figure 11.7 – Industrial (Large) Energy (GWh)

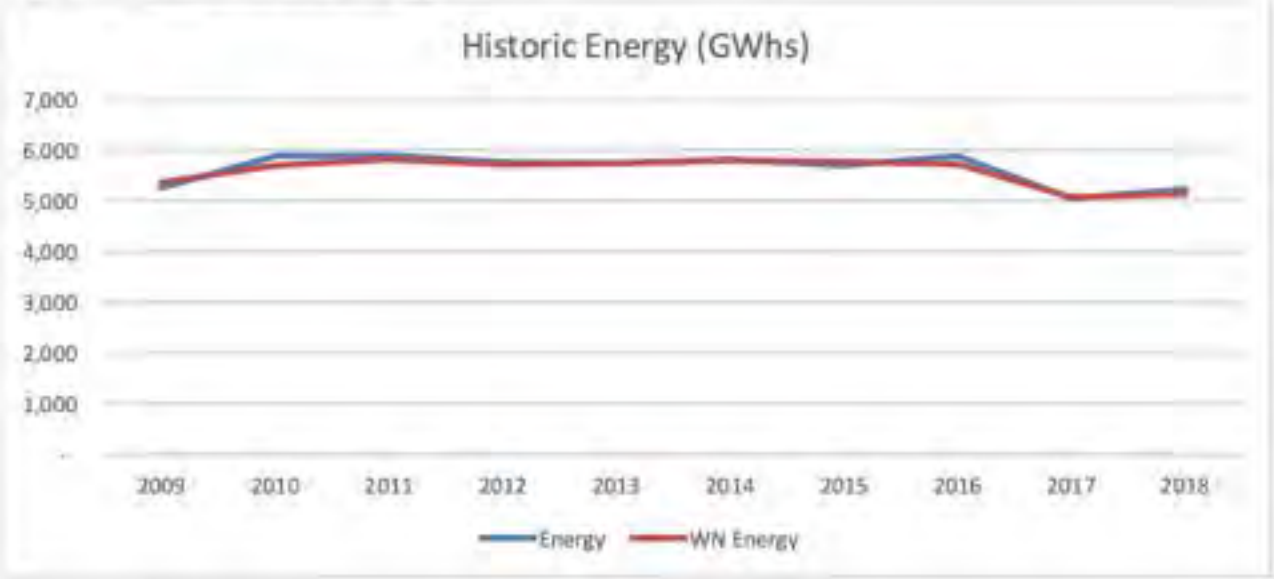
Year	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	2016 (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2007 % Diff	2009 % Diff	2011 % Diff	2014 % Diff	2016 % Diff
2009	2,820					2,251	-25.3%				
2010	2,921	2,281				2,601	-12.3%	12.3%			
2011	2,980	2,445				2,744	-8.6%	10.9%			
2012	2,999	2,449	2,687			2,714	-10.5%	9.8%	1.0%		
2013	3,014	2,449	2,693			2,744	-9.8%	10.7%	1.9%		
2014	3,028	2,446	2,693			2,788	-8.7%	12.2%	3.3%		
2015	3,040	2,445	2,688	2,916		2,722	-11.7%	10.1%	1.2%	-7.1%	
2016	2,718	2,447	2,679	2,932		2,722	0.2%	10.1%	1.6%	-7.7%	
2017	2,730	2,446	2,664	2,546	2,211	2,097	-30.2%	-16.7%	-27.1%	-21.4%	-5.5%
2018	2,742	2,440	2,646	2,547	2,252	2,182	-25.7%	-11.9%	-21.3%	-16.7%	-3.2%
Mean Absolute Error							14.3%	11.6%	8.2%	13.3%	4.3%

11.1.3.1 Actual and Weather Normalized Energy and Demand Levels

Figure 11.8 – Historic Peak Demand



Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

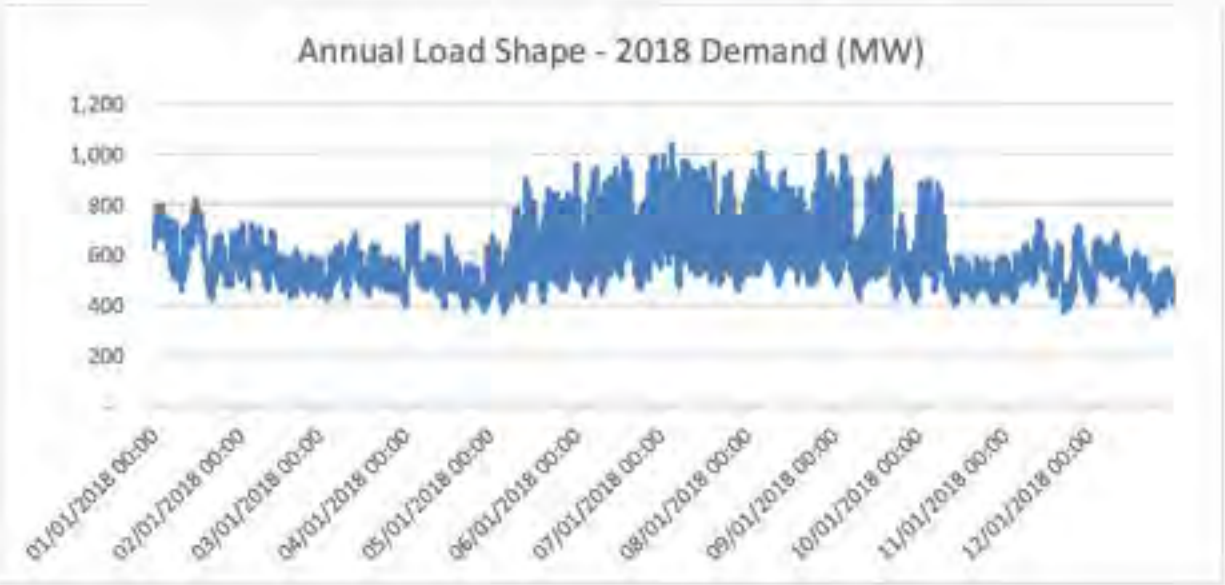


Figure 11.11 – Winter Peak Day

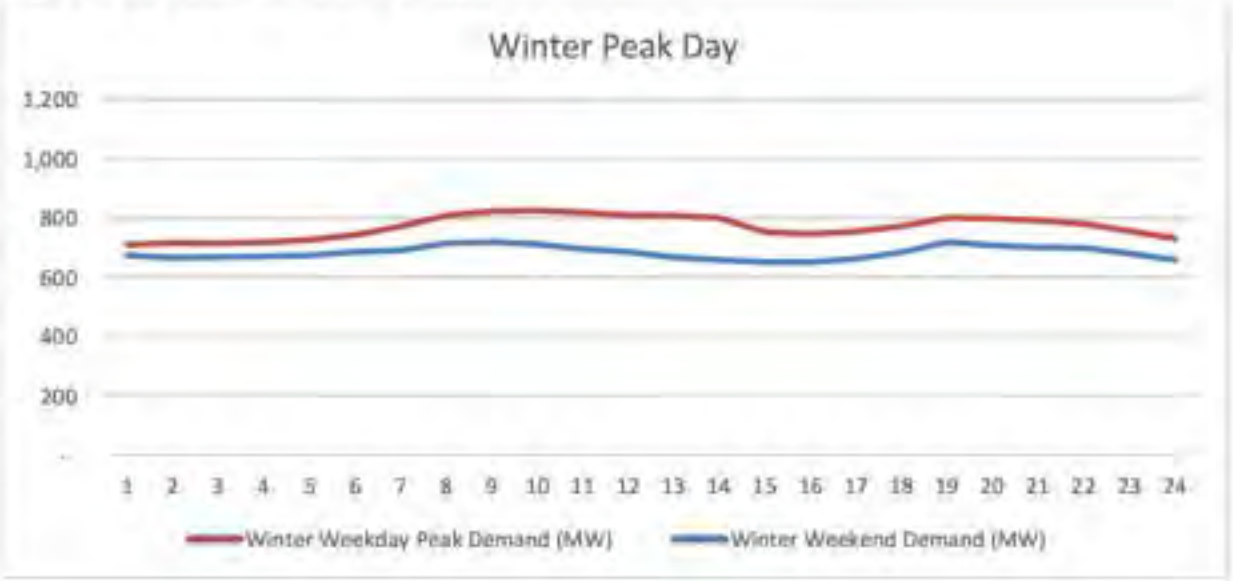


Figure 11.12 – Typical Spring Day

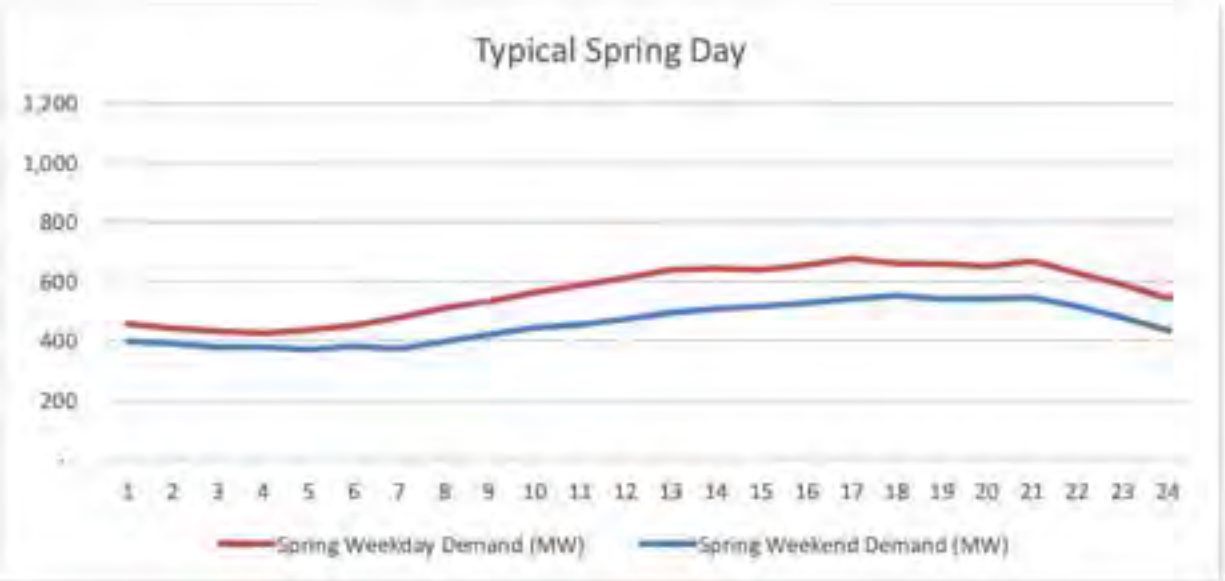


Figure 11.13 – Summer Peak Day

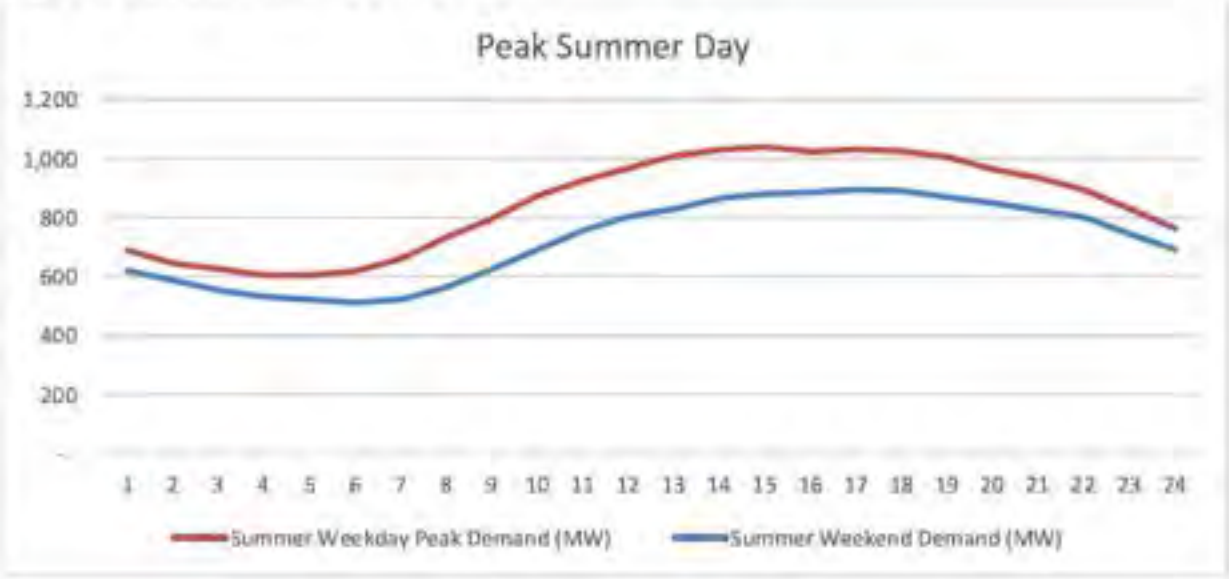


Figure 11.14 – Typical Fall Day

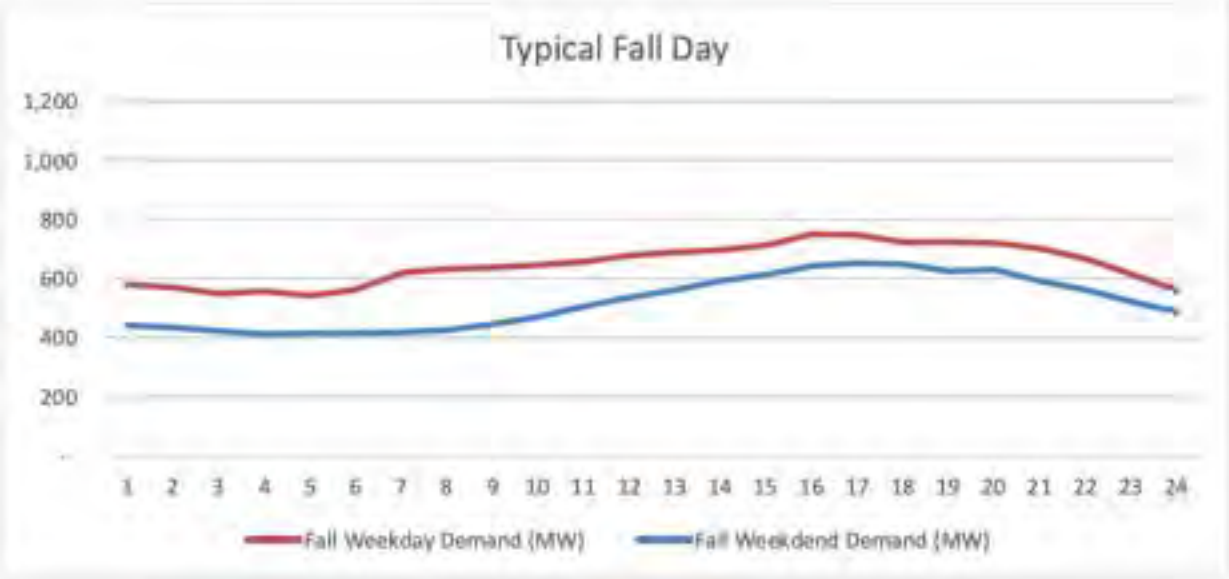


Figure 11.15 – January Load

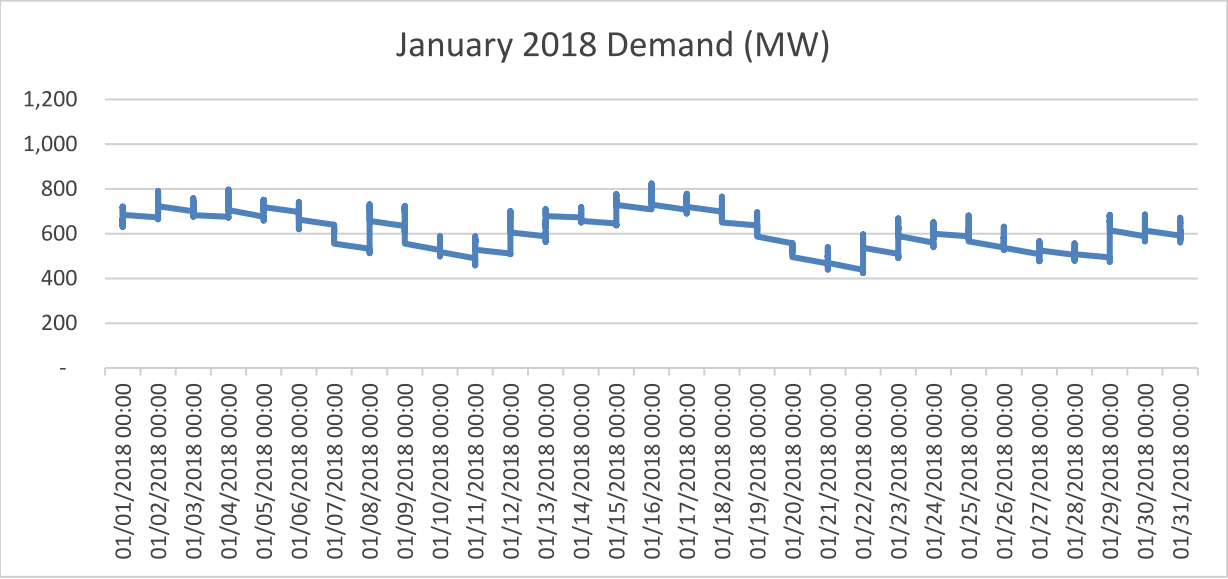


Figure 11.16 – February Load

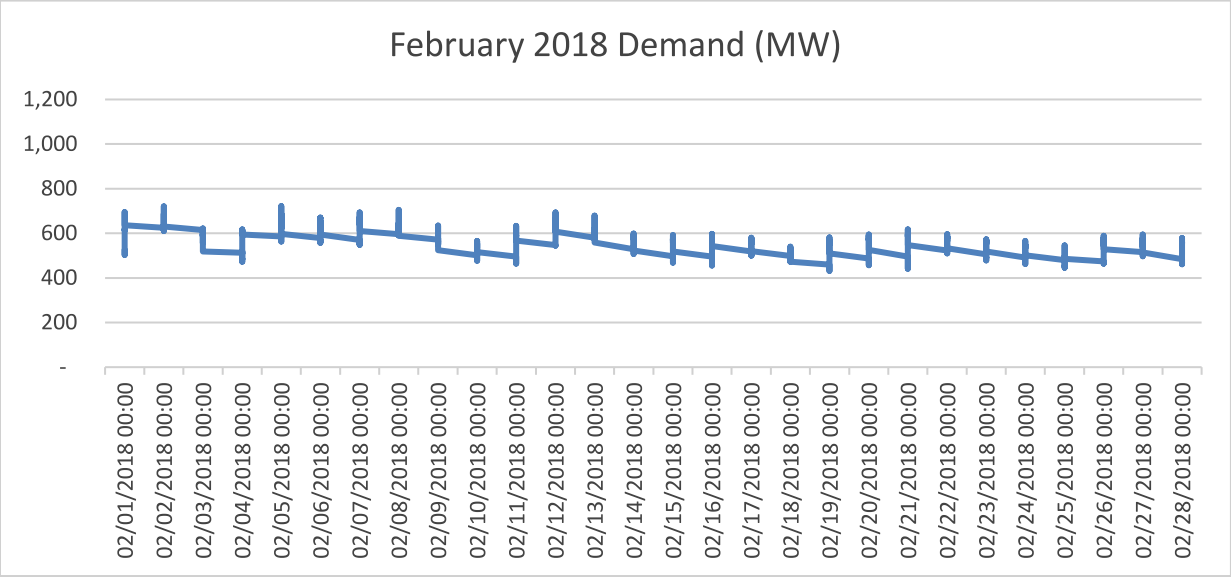


Figure 11.17 – March Load

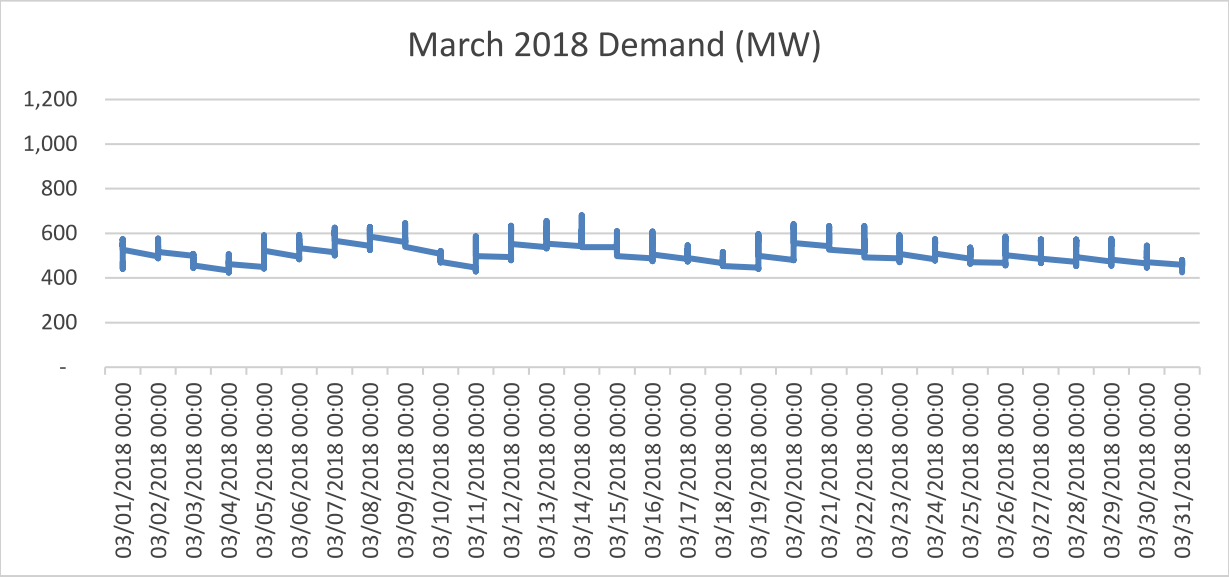


Figure 11.18 – April Load

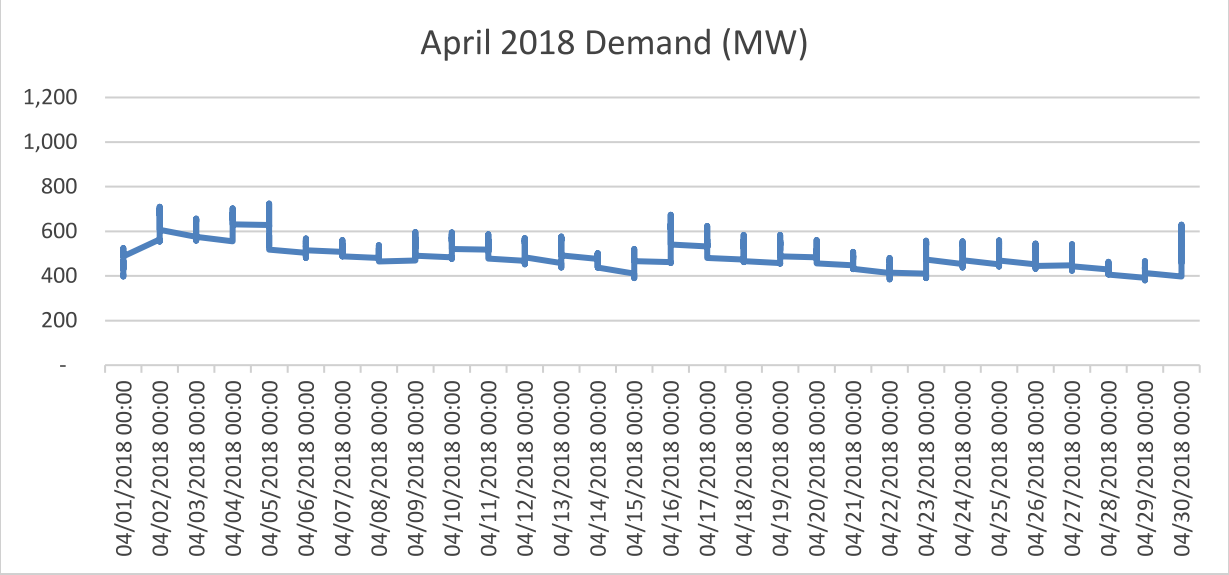


Figure 11.19 – May Load

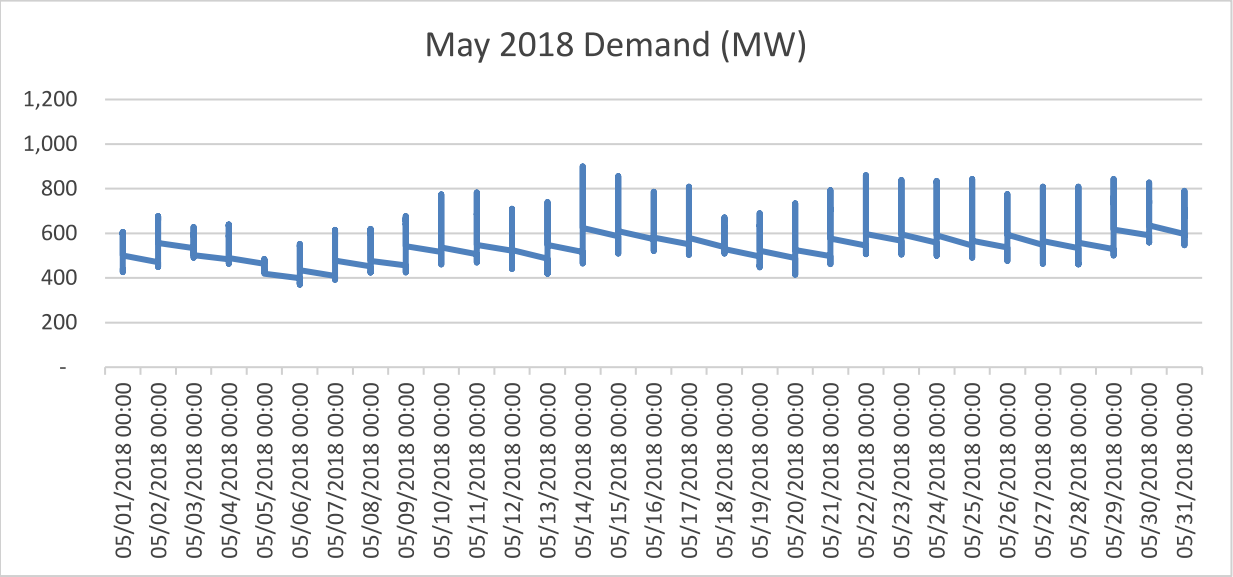


Figure 11.20 – June Load

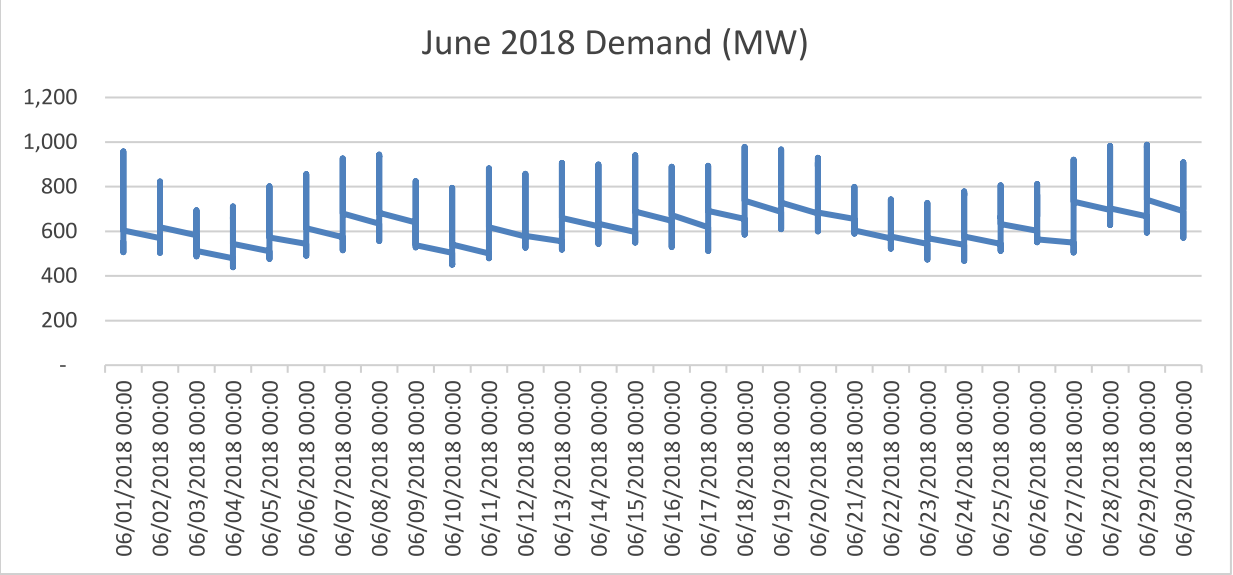


Figure 11.21 – July Load

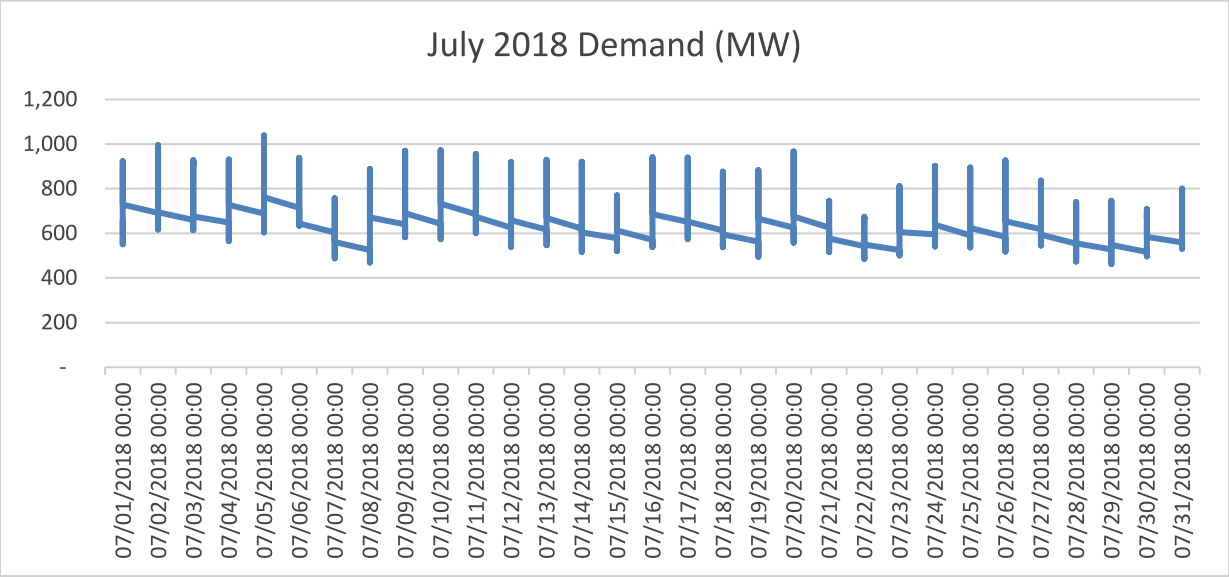


Figure 11.22 – August Load

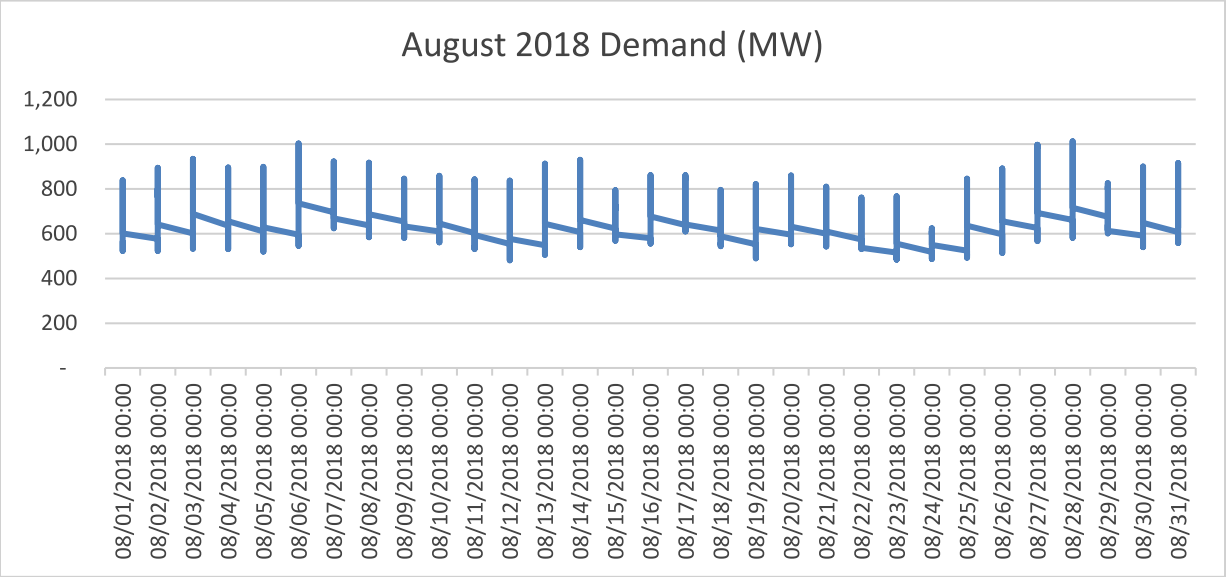


Figure 11.23 – September Load

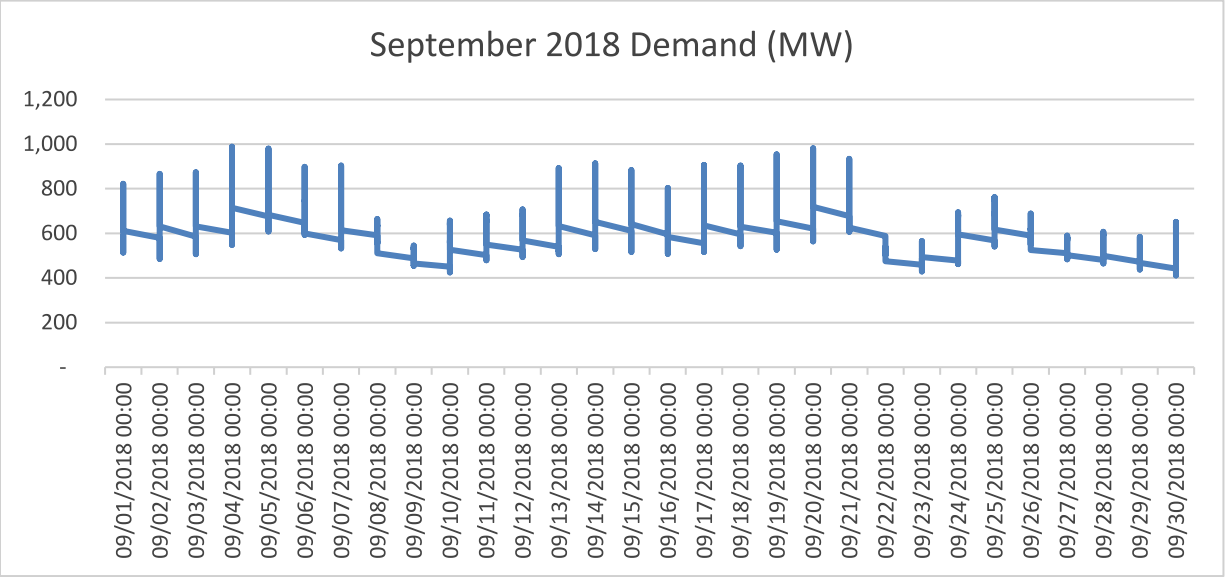


Figure 11.24 – October Load

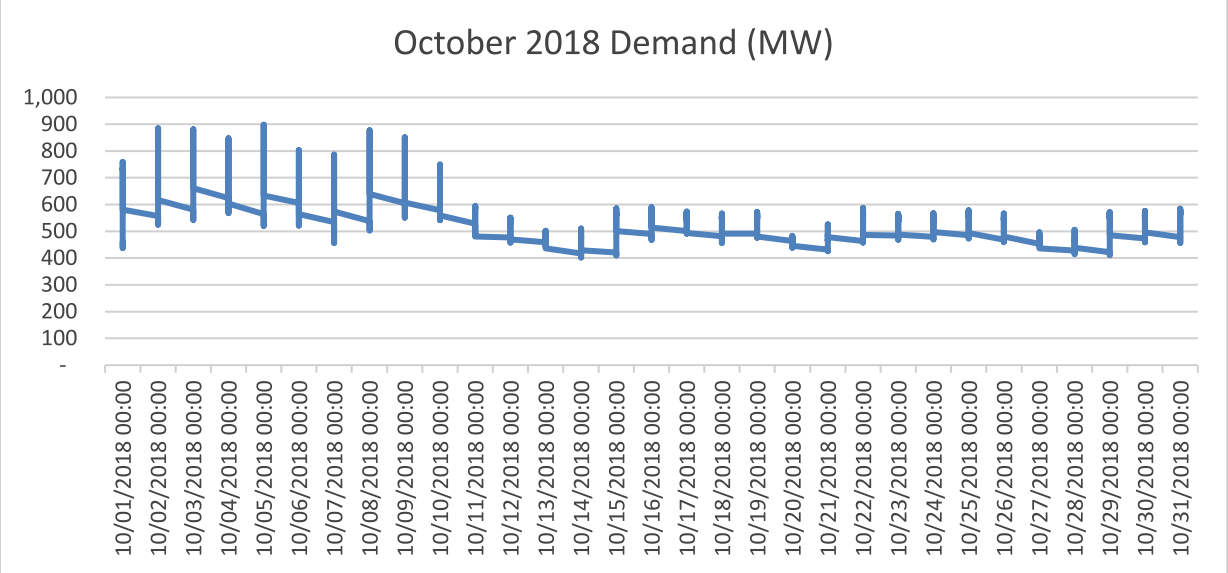


Figure 11.25 – November Load

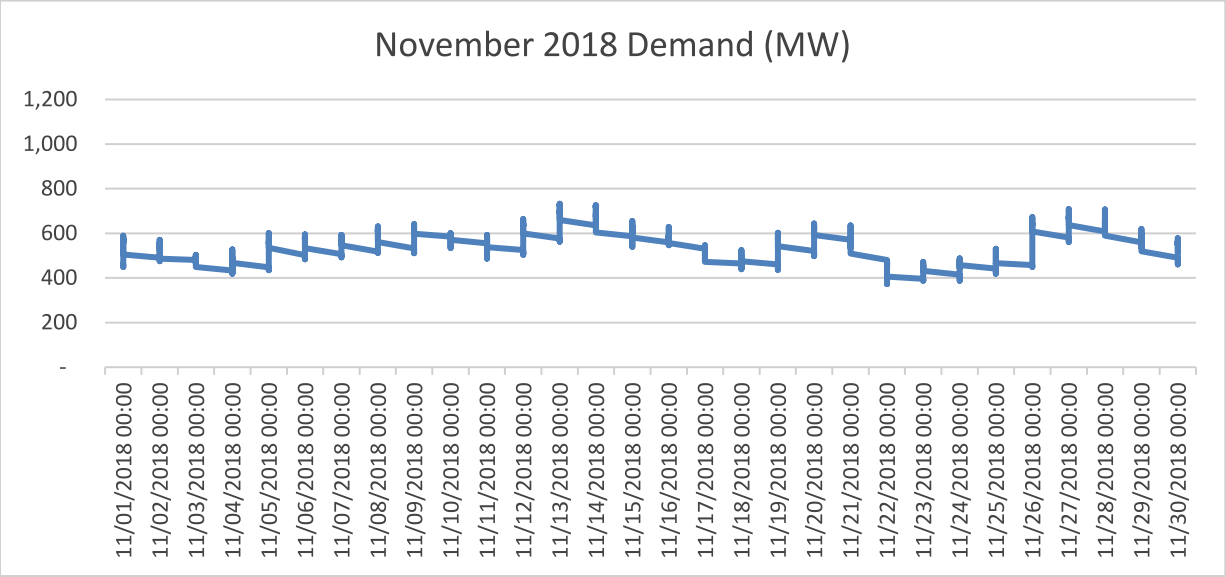
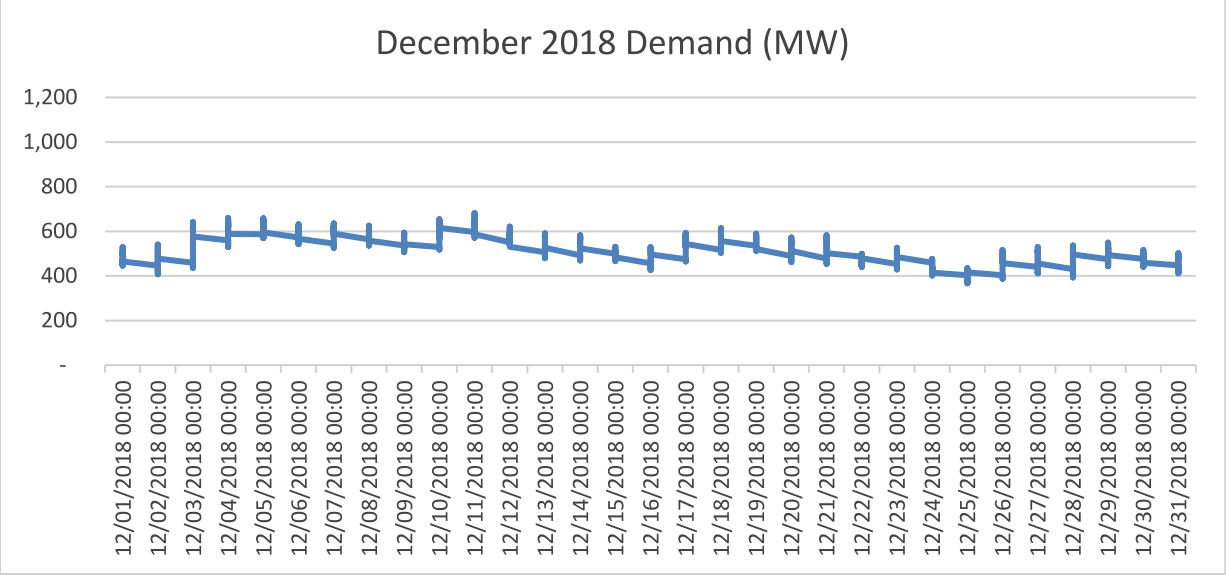


Figure 11.26 – December Load



11.2 ENVIRONMENTAL APPENDIX

11.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio. Air emissions allowance costs are accounted for within IRP modeling.

Figure 11.27 – Air Pollution Control Devices Installed

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

Figure 11.28 – CSAPR SO_2 Allowances

SO_2				
	A.B. Brown	F.B. Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	A.B. Brown	BAGS[47]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

[47] Retired

Figure 11.29 – CSAPR Seasonal NOx Allowances

	A.B. Brown	BAGS[48]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

11.2.2 Solid Waste Disposal

Scrubber by-products from A.B. Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management (IDEM). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of A.B. Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and instead transported offsite for recycling into a cement application.

Fly ash from the F.B. Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the A.B. Brown facility in late 2009, F.B. Culley's fly ash is now transported to the A.B. Brown loading facility and shipped to the cement plant via river barge. The F.B. Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. By the end of 2020, the East pond will no longer receive bottom ash as a result of the conversion to a dry system. The West pond (32 acres) no longer receives bottom ash but has continued to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. By the end of 2020, the West pond will be closed. The closure

[48] Retired

project includes the construction of a new geosynthetic lined contact storm water pond that will receive the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is also used for beneficial reuse and shipped by river barge from F.B. Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site but is being recycled and shipped off-site for beneficial reuse.

11.2.3 Hazardous Waste Disposal

Vectren's A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include 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.

11.2.4 Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (IDEM). A.B. Brown utilizes cooling towers 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.

11.3 DSM APPENDIX

11.3.1.1 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 Vectren'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 Vectren, the IRP is not the appropriate tool to determine which specific

programs to include in a DSM plan. Instead, every 2-3 years Vectren 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.

11.3.1.2 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. Vectren considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) 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 Total Resource Cost (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, Vectren used 6.19% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on May 29, 2019 in Cause No. 44910.

Figure 5.3.2.8.1 – Vectren 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)

11.3.2 Gross Savings 2018-2020 Plan

Figure 11.30 – 2018-2020 Plan Gross kWh Energy Savings

	2018		2019		2020	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,302,098	6,417	23,337,912	4,846	19,294,127	5,977
Commercial & Industrial	24,931,097	3,656	20,500,000	4,321	17,053,515	1,773
Total	48,233,193	10,073	43,837,912	9,167	36,347,642	7,750

* 2018 Evaluated Savings used for 2018
** 2019 Operating Plan used for 2019
*** 2020 Filed Plan used for 2020

11.3.3 DSM Programs

Vectren has offered tariff-based DSM resource options to customers for several years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren 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.

11.3.4 Impacts

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

Figure 11.31 – 2018 Evaluated Electric DSM Program Savings

Program	Residential/ Commercial	Participants *	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	235,192	58%	8,136,654	35	4,706,664	1,121	0.005	649.0
Residential Prescriptive	Residential	6,900	68%	3,326,588	482	2,277,461	1,667	0.242	1,098.0
Residential New Construction	Residential	145	54%	162,407	1,120	87,700	62	0.428	34.0
Home Energy Assessments	Residential	350	75%	341,133	975	256,938	31	0.089	23.0
Income Qualified Weatherization	Residential	2,043	100%	931,314	456	931,314	100	0.049	100.0
Energy Efficient Schools	Residential	2,401	100%	712,638	297	712,638	76	0.032	76.0
Residential Behavioral Savings	Residential	41,400	100%	7,063,475	171	7,063,475	1,839	0.044	1,838.7
Appliance Recycling	Residential	1,300	67%	1,326,520	1,020	891,359	169	0.130	114.0
BYOT (Bring Your Own Thermostat)	Residential	400	100%				358	0.895	358.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,043	100%	379,779	364	379,779	866	0.831	866.4
Community Based - LED Lighting	Residential	44,189	100%	921,588	21	921,588	127	0.003	127.0
Evaluated Nonparticipant Spillover	Residential					1,012,564			
Commercial & Industrial Prescriptive	Commercial	37,200	84%	18,605,544	500	15,628,657	2,713	0.073	2,278.7
Commercial & Industrial Custom	Commercial	40	85%	2,512,038	62,801	2,135,232	324	8.100	276.0
Small Business Direct Install	Commercial	138	101%	3,813,515	27,634	3,837,960	619	4.486	623.0
Portfolio Total		372,741	85%	48,233,193	129	40,843,329	10,073	0.027	8,461.8

* Participants are the Verified installations

Figure 11.32 – 2019 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	241,418	72%	8,340,633	35	6,005,256	939	0.004	675.7
Residential Prescriptive	Residential	4,314	53%	2,318,054	537	1,228,569	957	0.222	507.2
Residential New Construction	Residential	171	50%	157,033	918	78,517	90	0.526	45.0
Home Energy Assessments	Residential	400	99%	403,067	1,008	399,036	42	0.105	41.6
Income Qualified Weatherization	Residential	851	100%	546,248	642	546,248	95	0.112	95.0
Energy Efficient Schools	Residential	2,500	100%	962,750	385	962,750	108	0.043	108.0
Residential Behavioral Savings	Residential	41,400	100%	7,370,000	178	7,370,000	961	0.023	961.0
Appliance Recycling	Residential	1,500	53%	1,491,900	995	790,707	198	0.132	104.9
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	198,000	198	198,000	1,015	1.015	1,014.5
Community Based - LED Lighting	Residential	50,496	100%	1,550,227	31	1,550,227	202	0.004	202.0
Commercial & Industrial Prescriptive	Commercial	40,179	75%	13,500,000	336	10,125,000	3,612	0.090	2,709.0
Commercial & Industrial Custom	Commercial	44	96%	3,500,000	79,545	3,360,000	450	10.227	432.0
Small Business Direct Install	Commercial	78	86%	3,500,000	44,872	3,010,000	259	3.321	222.7
Portfolio Total		384,751	81%	43,837,912	114	35,624,309	9,167	0.024	7,358.7

Figure 11.333 – 2020 Electric DSM Filed Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	163,416	67%	6,075,005	37	4,070,253	791	0.005	530.0
Residential Prescriptive	Residential	6,595	52%	1,979,280	300	1,029,226	1,910	0.290	993.3
Residential New Construction	Residential	139	50%	187,038	1,346	93,519	118	0.849	59.0
Home Energy Assessments	Residential	1,210	98%	863,991	714	846,711	192	0.159	188.2
Income Qualified Weatherization	Residential	525	100%	1,130,945	2,154	1,130,945	540	1.029	540.2
Energy Efficient Schools	Residential	2,600	100%	645,216	248	645,216	53	0.020	52.8
Residential Behavioral Savings	Residential	35,298	100%	5,600,000	159	5,600,000	1,153	0.033	1,153.0
Appliance Recycling	Residential	920	54%	884,915	962	477,854	117	0.127	63.1
Conservation Voltage Reduction	Residential	5,324	100%	1,461,047	274	1,461,047	263	0.049	263.1
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	466,690	467	466,690	600	0.600	600.0
Community Based - LED Lighting	Residential								
Commercial & Industrial Prescriptive	Commercial	6,856	87%	5,002,621	730	4,352,280	369	0.054	321.0
Commercial & Industrial Custom	Commercial	93	100%	7,002,080	75,291	7,002,080	633	6.806	633.0
Small Business Direct Install	Commercial	131	95%	4,016,159	30,658	3,821,144	585	4.466	556.7
Conservation Voltage Reduction	Commercial	558	100%	1,032,655	1,851	1,032,655	186	0.333	185.9
Portfolio Total		225,065	88%	36,347,642	161	32,029,620	7,750	0.034	6,379.2

11.3.5 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 236 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 Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2027, 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 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 236 MW 1x F-class simple cycle gas turbine is avoided.

Figure 11.34 – Avoided Costs

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2020	$148.60	$6.36	**$154.96**	$2.98	$0.00	$28.63
2021	$151.87	$6.43	**$158.30**	$3.16	$0.00	$30.06
2022	$155.21	$6.55	**$161.76**	$3.37	$0.00	$34.99
2023	$158.63	$6.73	**$165.35**	$3.63	$0.00	$35.77
2024	$162.12	$6.71	**$168.82**	$3.83	$0.00	$36.81
2025	$165.68	$6.83	**$172.51**	$4.00	$0.00	$38.82
2026	$169.33	$6.99	**$176.31**	$4.19	$0.00	$39.80
2027	$173.05	$7.15	**$180.20**	$4.35	$4.34	$44.04
2028	$176.86	$7.32	**$184.18**	$4.52	$5.07	$46.36
2029	$180.75	$7.50	**$188.25**	$4.68	$6.48	$48.37
2030	$184.73	$7.63	**$192.36**	$4.87	$7.95	$50.18
2031	$188.79	$7.81	**$196.60**	$5.06	$8.80	$51.76
2032	$192.94	$7.98	**$200.93**	$5.27	$9.68	$52.59
2033	$197.19	$8.16	**$205.35**	$5.51	$10.60	$54.94
2034	$201.53	$8.34	**$209.87**	$5.73	$11.56	$56.60

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2035	$205.96	$8.52	**$214.48**	$6.02	$13.29	$59.93
2036	$210.49	$8.71	**$219.20**	$6.23	$15.09	$61.52
2037	$215.12	$8.90	**$224.02**	$6.48	$16.97	$64.69
2038	$219.86	$9.10	**$228.95**	$6.70	$19.71	$69.00
2039	$224.69	$9.30	**$233.99**	$6.90	$23.36	$72.04

*Transmission costs derived from switchyard upgrade on brownfield A.B. Brown site

*Distribution costs derived from average investment per lot

**Assumes average of winter/summer delivered to S. Indiana

***Based on Vectren Reference Case (Around-the-Clock prices shown)

11.3.6 Estimated Impact on Historical and Forecasted Peak Demand and Energy

11.4 RESOURCE OPTIONS APPENDIX

11.4.1 Existing Resource Studies

11.4.1.1 Existing Brown Scrubber Assessment

Both A.B. Brown units are scrubbed for sulfur dioxide (SO2) emissions, utilizing a dual-alkali flue gas desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. A.B. Brown Unit 1 FGD has reached 40 years of service life and Unit 2 FGD has reached 33 years of service life as of 2019. The operating life of these scrubbers has been impacted by a combination of the acidic and caustic dual-alkali conditions, which are both very damaging to structural steel and concrete. Continual maintenance and repairs have been completed throughout the many years of service. Despite these continuous repair and maintenance efforts, many steel elements and foundations exhibit severe corrosion. Structural assessment studies have been completed by a local engineering firm, Three I Design. Major replacements and repairs have been identified to further the existing FGD operation another 10 years to

2029. Three i Design provided costs for upgrading and refurbishing the existing FGD system to extend the life through the 10-year period.

11.4.1.2 Replacement Scrubber Options at Brown

New replacement FGD technologies at A.B. Brown, identified in Table 10-1 have been evaluated for availability and applicability. Technically feasible options that are both available and applicable to A.B. Brown had high level AACE Class 5 installation cost estimates developed.

Table 10-1 Identify Available and Applicable Technologies

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Wet FGD		
Limestone Conversion of Existing Dual-Alkali FGD - Forced Oxidation (DA-LSFO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Limestone Conversion of Existing Dual-Alkali FGD - Inhibited Oxidation (DA-LSIO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Wet Limestone FGD - Forced Oxidation[1] (LSFO)	Yes	Yes – New installations are capable of meeting performance standards.
Wet Lime FGD - Inhibited Oxidation[1] (WLIO)	Yes	Yes– New installations are capable of meeting performance standards.
Spray Dryer Absorber (SDA)	Yes	No – SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
Circulating Dry Scrubber (CDS) or Turbosorp	Yes	Yes – Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown.
Flash Dryer Absorber (FDA)	Yes	No – FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Ammonia Scrubber (NH_3)	Yes	Yes – However, only one small US industrial application in operation and current interest limited to one Chinese supplier with no US experience
Powerspan ECO Process	No	No – Only pilot size experience

(1) Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.

Analysis was inclusive of FGD options necessary to keep the A.B. Brown Units 1 and 2 in compliance with current SO2 emissions limits and maintaining compliance with existing Hg and H2SO4 emissions requirements. Based on these requirements the DA-LSIO and DA-LSFO conversion options will not meet emissions performance criteria. High level capital installation estimates were developed by Black & Veatch for the Wet Lime FGD Inhibited Oxidation (WLIO), Circulating Dry Scrubber (CDS) and Ammonia Scrubber (NH3). Burns & McDonnell developed an estimate for the Wet Limestone FGD Forced Oxidation (LSFO), building on their previous experience with this technology assessment at A.B. Brown. Capital and O&M estimates for these remaining four technologies were evaluated by PACE Global screening using analysis consistent with the IRP evaluation Reference Case. The least cost option was selected and included in the BAU portfolio. Note that there are risks such as byproduct market availability, byproduct disposal requirements and reagent supply availability. These risks were qualitatively assessed independent of the screening analysis.

For the BAU to 2039 portfolio, an analysis of the most economic FGD scrubber option was conducted. Each of the four scrubber technologies was evaluated in the Aurora model with identical model runs except for the difference of the scrubber technology costs and performance metrics. The analysis demonstrated that the DA-LSIO was the least cost FGD scrubber technology among the four options. The DS-LSFO option was shown to increase portfolio costs by 1.51% all other things being equal, the NH3 option was shown to be 1.66% more costly and the CDS option was shown to be 2.95% more costly.

Accordingly, the DA-LSIO option was selected for modeling purposes in the BAU to 2039 portfolio.

11.4.1.3 Coal to Gas Conversion

The conversion of A.B. Brown Unit 1 and 2 existing coal fired boilers to burn natural gas instead of coal was studied. Conceptual design studies were developed by engineering firms and OEM suppliers to determine natural gas conversion MW output, heat rate performance, emissions and balance of plant equipment. Engineering and construction estimates were developed to determine high level AACE Class 4 installation costs. The converted plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. These units were originally designed as base load coal units. The boiler metallurgy and turbine were not designed for cycling operation. The impacts of cycling will require increased maintenance of this equipment compared to previous coal operations. Startup durations remain the same as coal fired operations continuing to limit the response time in a cycling environment. Natural gas conversion of the units reduces boiler efficiency compared to the coal fired design and increase net plant heat rate.

11.4.1.4 ACE Rule Compliance

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) June 19, 2019, establishes new standards for reducing greenhouse gas emissions for coal fired electric utility generating units. ACE details specific heat rate improvement techniques, called Best System of Emission Reduction (BSER), that are meant to be the best technology options or other measures that have been known to reduce plant heat rate.

The specific candidate technology options are as follows:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.

- Variable frequency drive (VFD) deployment.
- Neural networks.
- Intelligent sootblowing (ISB).
- Boiler Feed Pump Upgrades.
- Equipment & facilities improvements to enhance operations and maintenance (O&M) practices.

The potential alternatives for improvements at the four coal fired units A.B. Brown Units 1 & 2 and F.B. Culley Units 2 & 3 were assessed to meet the goals of the ACE rule. Applicability of candidate technologies for the four existing coal fired units is found in the "ACE Heat Rate Improvement Study" located in technical appendix 6.8. The characteristics of the four plants were reviewed and each plant was examined according to applicable BSER alternatives. Estimates of heat rate improvement, annual carbon dioxide reduction, O&M and a rough order of magnitude capital cost estimate were developed for each applicable alternative.

11.4.2 Approximate Net and Gross Dependable Generating Capacity

Figure 11.35 – Approximate Net and Gross Dependable Generating Capacity

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
A.B. Brown 1	265	245
A.B. Brown 2	265	245
A.B. Brown 3	74	74
A.B. Brown 4	74	74
F.B. Culley 2	100	90
F.B. Culley 3	287	270
Warrick 4	162	150

11.4.3 New Construction Alternatives

Figure 11.36 – New Construction Alternatives

Technology	Fuel	Capacity (kW)
Biomass	Biomass	50,000
Energy Efficiency Bins 1-7 (2021-23)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2024-26)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2027-39)	Energy Efficiency	Varies
Hydroelectric	Hydro	50,000
Landfill Gas	Landfill Gas	4,500
F-Class CT	Natural Gas	236,635
E-Class CT	Natural Gas	84,721
GH-Class CT	Natural Gas	279,319
F-Class CCGT	Natural Gas	442,400
GH-Class CCGT	Natural Gas	510,700
Generic Solar PV	Solar	10,000
Generic Solar PV	Solar	50,000
Generic Solar PV	Solar	100,000
12to15 Year Solar PPA	Solar	112,500
20 Year Solar PPA	Solar	200,000
20 Year Solar PPA	Solar	165,460
25to30 Year Solar PPA	Solar	137,500
Li-Ion Battery Storage (4 hour)	Storage	10,000
Li-Ion Battery Storage (4 hour)	Storage	50,000
Flow Battery Storage (6 hour)	Storage	10,000
Flow Battery Storage (6 hour)	Storage	50,000
Flow Battery Storage (8 hour)	Storage	10,000
Flow Battery Storage (8 hour)	Storage	50,000
Li-Ion Battery Storage (paired with Generic Solar PV) (4 hour)	Storage	10,000
Li-Ion Battery Storage (paired with Generic Wind) (4 hour)	Storage	10,000
Annual MISO Capacity Market Purchase	Capacity	Up to 180,000
Li-Ion Battery Storage PPA (4 hour)	Storage	76,200
Solar PV (paired with Storage) PPA	Solar	133,333
Li-Ion Battery Storage (paired with Solar) PPA (4 hour)	Storage	42,000
Demand Response Bin 1 (2021-23)	Storage	Varies

Technology	Fuel	Capacity (kW)
Demand Response Bin 2 (2024-26)	Storage	Varies
Demand Response Bin 3 (2027-39)	Storage	Varies
Generic Wind	Wind	200,000
Generic Wind	Wind	50,000
12to15 Year Wind PPA	Wind	200,000
20 Year Wind PPA	Wind	300,000

11.5 RISK APPENDIX

Probabilistic modeling incorporates five key market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of future market conditions. Quantitative data are extracted from the results and is the foundation for the balanced scorecard. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (for Vectren, MISO Local Resource Zone 6 and all of MISO) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. The 200 iterations of each stochastic variable are then inputted into the Aurora model. This allows for the testing of each candidate portfolio's performance across a wide range of market conditions.

All portfolios were subjected to each of the 200 iterations (scenarios) using the dispatch module in the Aurora model where the Vectren portfolios are fixed but other market participants can make decisions under each market scenario. The entire Eastern Interconnection except FRCC and ISO-NE was run stochastically in each scenario. The risk analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the Aurora model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas

prices, coal prices, carbon prices and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term and long-term.

- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the Aurora production cost model. Aurora dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, Aurora assumes that each candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the risk analysis.

11.6 Stochastic Distributions

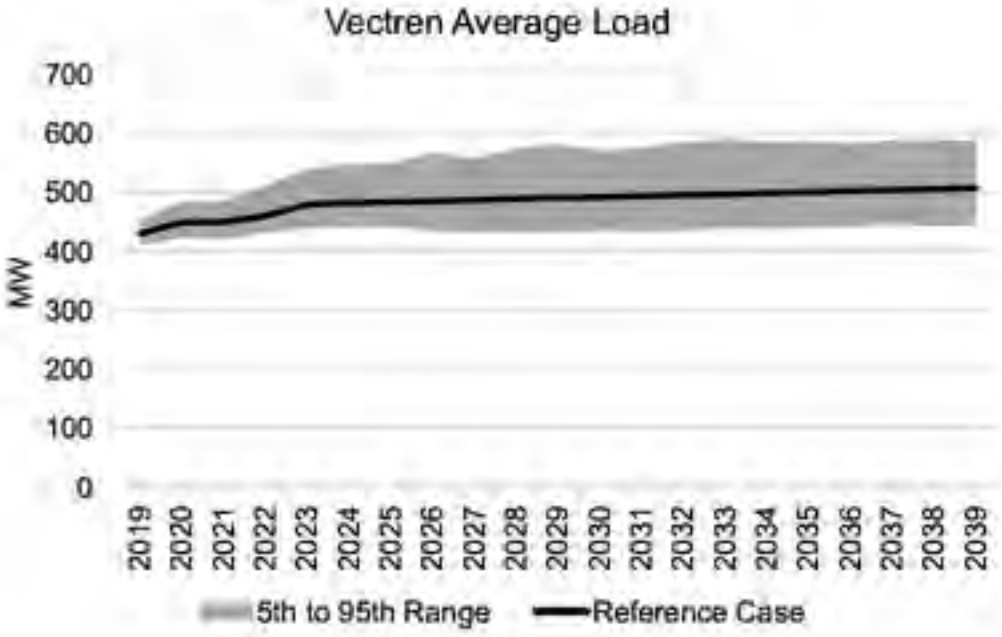
In order to perform the probabilistic modeling (stochastics), a set of probability distributions was required for each of the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables.

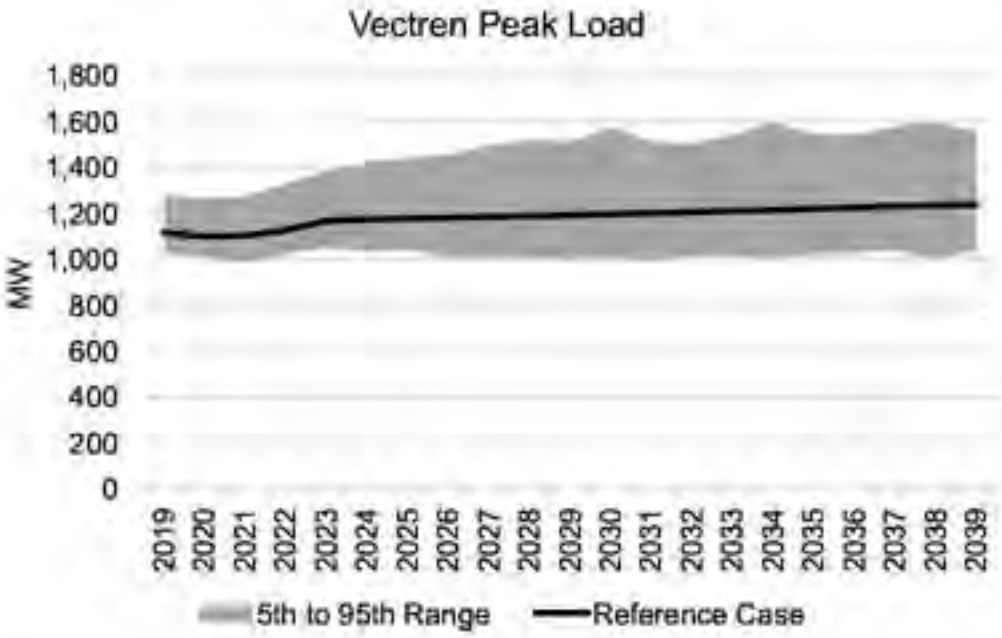
11.6.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the average and peak load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and utilities not served by an ISO in SERC. Pace Global benchmarked the MISO-wide projections against MISO-sponsored load forecasting studies that are conducted by independent consultants,

institutions and market monitors and then released into the public domain. In addition, solar distributed generation (a decrement to Vectren load) and electric vehicles demand (an increment to Vectren load) were developed independently and incorporated into the Vectren load stochastics.

Exhibit 1: Vectren Load Distribution (Megawatts)



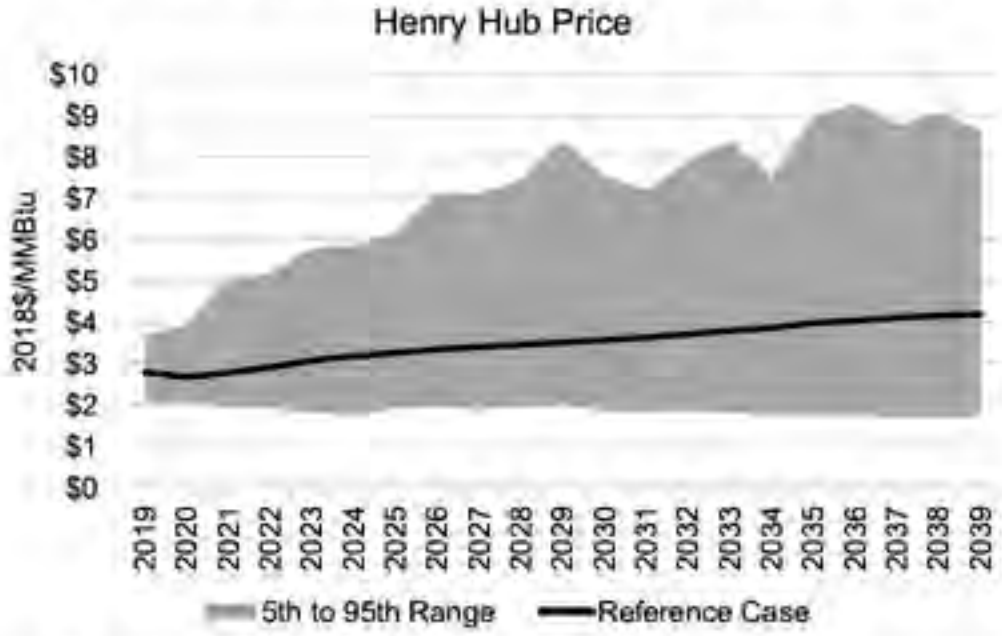


Source: Pace Global

11.6.2 Natural Gas Price Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

Exhibit 2: Natural Gas (Henry Hub) Price Distribution (2018$/MMBtu)

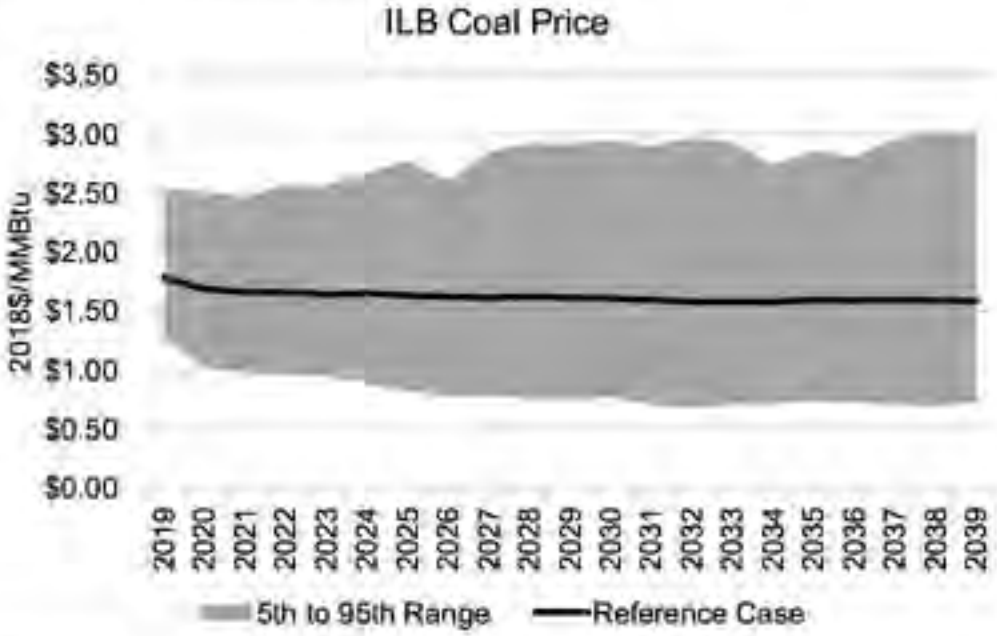


Source: Pace Global

11.6.3 Coal Price Stochastics

Pace Global developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on the consensus Reference Case view of coal prices with probability bands developed, then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Mercantile Exchange (NYMEX). The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

Exhibit 3: Coal Price Distribution (2018$/MMBtu)



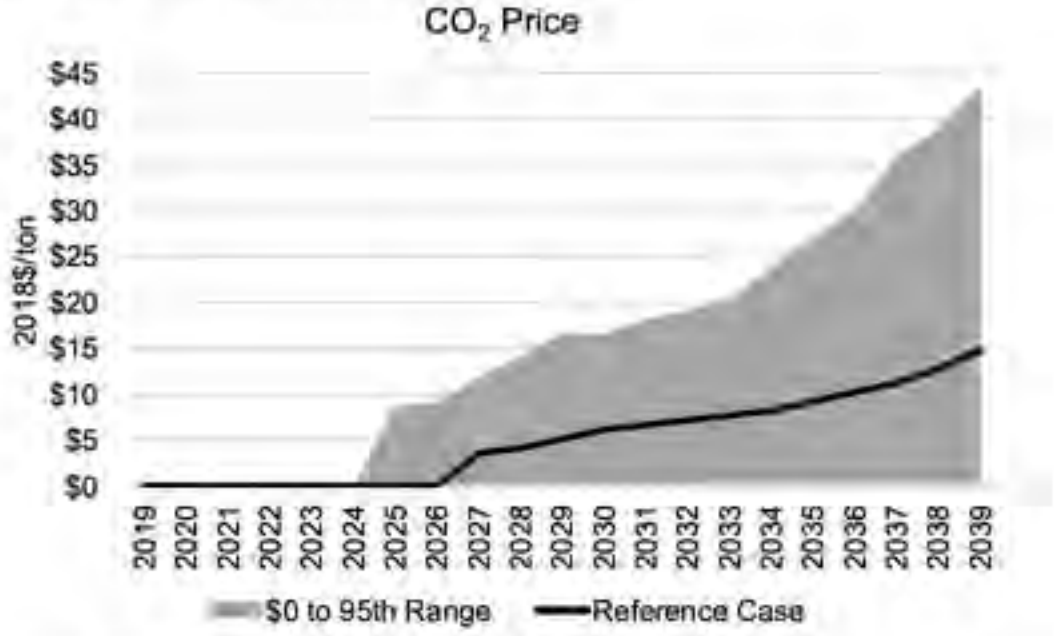
Source: Pace Global

11.6.4 CO_2 Emissions Price Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no

national historical data sets (only regional markets in California and the northeast U.S.) to estimate the parameters for developing carbon costs distributions. The consensus Reference Case CO_2 price outlook reflects a view that some type of legislation will likely occur in the mid-2020s to provide incentives for faster shifts from fossil to renewable generation. Previous studies of a proposed trading mechanism showed prices rising to about $15/ton. The bottom end of the distribution assumes no future regulation. The top end reflects the social cost of a carbon emission program. Two portfolios (HB 763 and High Regulatory) were optimized using CO_2 prices that exceeded the 95th percentile shown below.

Exhibit 4: CO_2 Price Distribution (2018$/ton)



Source: Pace Global

11.6.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined

cycles units, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a consensus Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the consensus Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

Exhibit 5: Solar Capital Costs Distribution (2018$/kW)

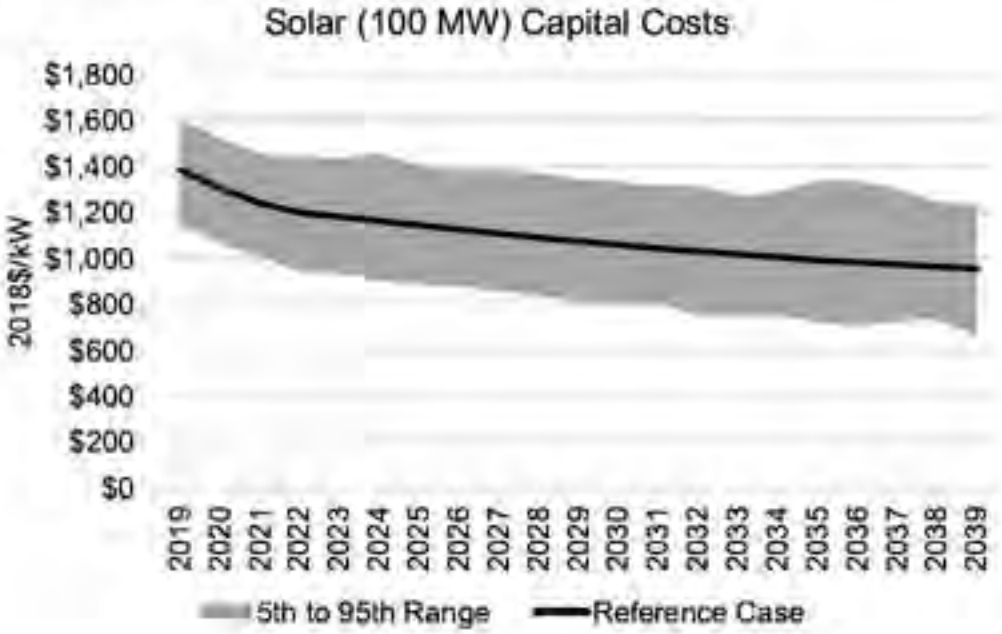
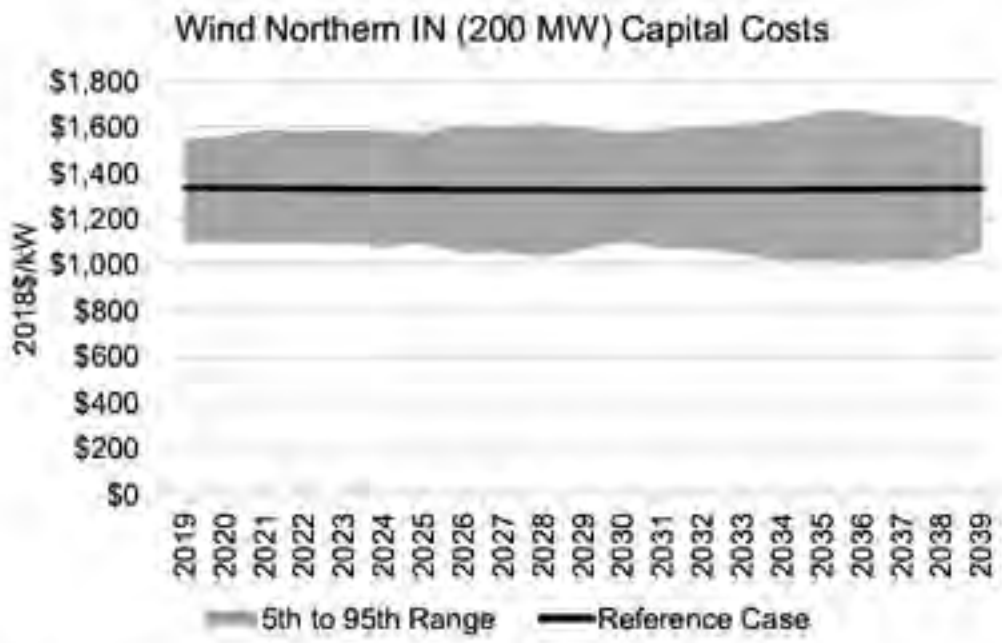


Exhibit 6: Wind Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 7: Battery Storage Capital Costs Distribution (2018$/kW)

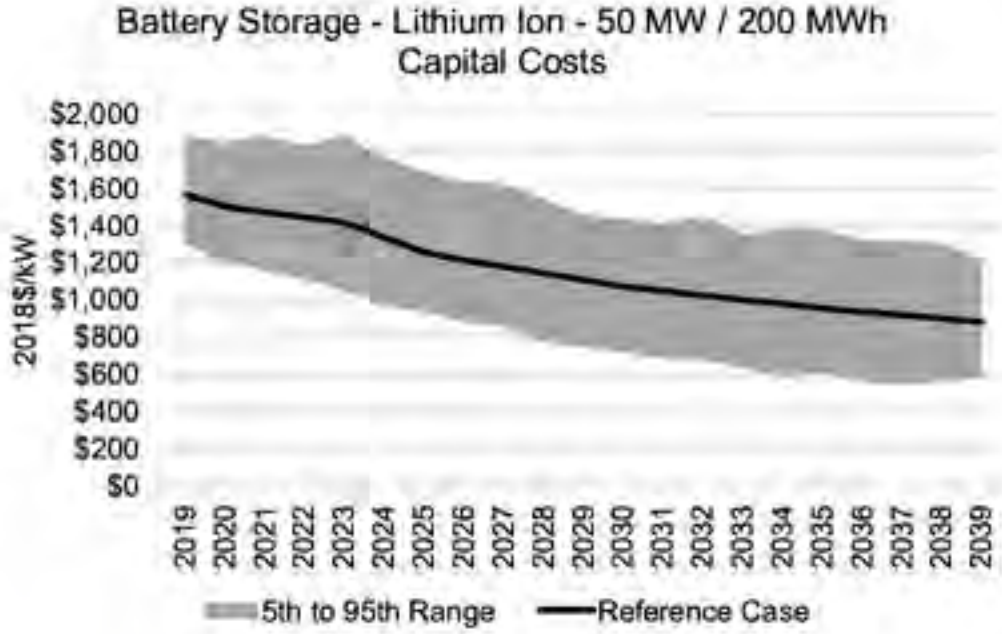
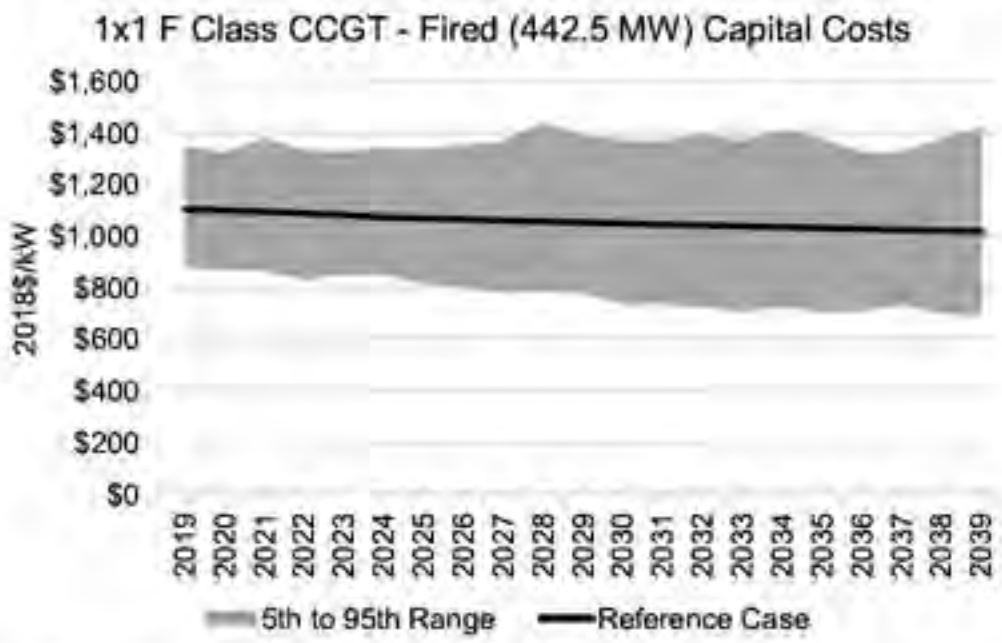
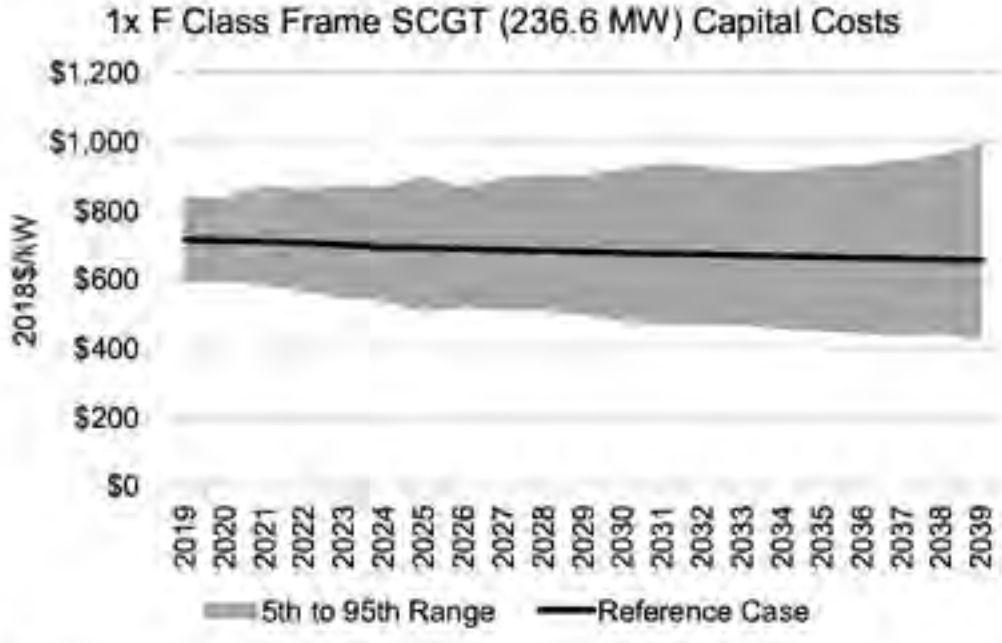


Exhibit 8: Advanced Combined Cycle Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 9: Advanced Combustion Turbine Capital Costs Distribution (2018$/kW)



Source: Pace Global

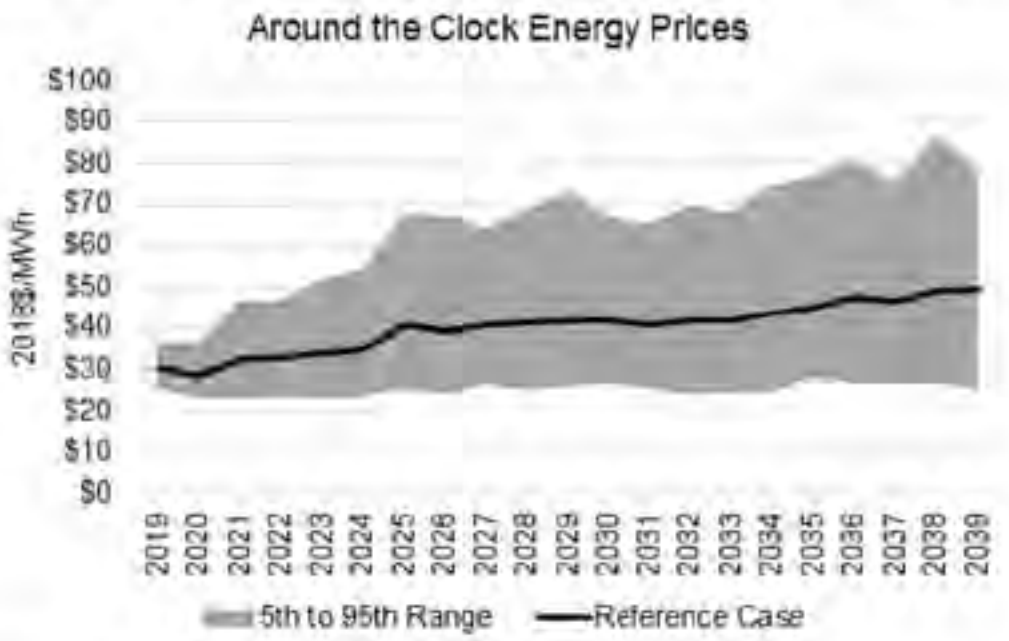
11.6.6 Cross-Commodity Stochastics

Pace Global captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

11.6.7 Energy Price Distribution

Pace Global produces a stochastic distribution of energy prices as a result of running the input distributions through Aurora (200 times). Aurora not only determines the build decisions for the region but also the resulting prices. The exhibit below displays these prices.

Exhibit 1: Stochastic Inputs – Energy Prices – Market Forecast



11.6.8 Affordability Ranking

Figure 11.37 – Probabilistic 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[49]	% above lowest cost
Renewables + Flexible Gas	$2,526	99.6%
Reference Case	$2,536	100.0%
High Technology (Preferred Portfolio)	$2,590	102.2%
All Renewables by 2030	$2,613	103.0%
Bridge ABB1 Conversion	$2,675	105.5%
Diverse Small CCGT	$2,680	105.7%
Business as Usual to 2029	$2,689	106.0%
ABB1+ABB2 Conversions	$2,834	111.8%
ABB1 Conversion + CCGT	$2,872	113.3%
Business as Usual to 2039	$2,912	114.8%

[49] The NPV of energy procurement is an indicative component of rates

11.7 TRANSMISSION APPENDIX

11.7.1 Transmission and Distribution Planning Criteria

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

a) Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet Vectren customers' needs during normal conditions and during a system contingency or set of contingencies;
b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) 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;
f) Coordinating transmission planning activities in broader regional evaluations with the Midcontinent Independent System Operator (MISO), ReliabilityFirst (RF) and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth and to address age and condition of existing facilities; and

j) Ensuring compliance with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

11.7.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren 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. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) 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. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren 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 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 a 345kV Market Efficiency Project between Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line; however, the project was awarded to Republic Transmission, LLC. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

11.7.3 Annual Transmission Assessment

Vectren's most recent transmission assessment was completed in 2019. The study used the final Multiregional Modeling Working Group (MMWG) 2018 Series Models, which includes the Vectren full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.11 software was used to conduct the assessment.

Vectren's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the 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 2019, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-19.

The Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. 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, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

The only mentionable extreme contingency is for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that Vectren prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System (BES). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2021).

- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2024).

These are not NERC reliability driven projects, but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Toyota South and Tepe Park are new distribution substations recently installed to meet load growth. The Tepe Park substation project also facilitates 4kV to 12kV conversion projects.

SECTION 12
TECHNICAL APPENDIX ATTACHMENTS

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Attachment 6.1 Vectren Electric 2018-2020 DSM Plan

Attachment 6.2 2019 DSM Market Potential Study

Attachment 6.3 All-Source RFP

Confidential Attachment 6.4 1x1 CCGT Study

Attachment 6.5 Coal to Gas Conversion Study

Attachment 6.6 Brown Scrubber Assessment Study

Attachment 6.7 Environmental Compliance Options Study

Attachment 6.8 ACE Rule Heat Rate Study

Attachment 8.1 Balance of Loads and Resources

Attachment 8.2 Confidential Aurora Input Model Files

Attachment 8.3 Aurora Output Model Files (submitted via DVD)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 116
CenterPoint 2023 IRP

2022/2023

Integrated Resource Plan



CenterPoint Energy

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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.		2022/2023 IRP submitted on May 26, 2023
(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.		12 Technical Appendix Attachments 1.1-8.2
(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

	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.		3.3 Stakeholder Input; 12 Technical Appendix Attachment 3.1 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.		3 Public Participation Process
(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:		3.1 Public Participation Process
(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.		3 Public Participation Process; 12 Technical Appendix Attachment 3.1 Stakeholder Materials
(2) The utility may hold additional meetings.		3.1 Public Participation Process
(3) The schedule for meetings shall: (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.		3 Public Participation Process

	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.		4.6 Energy and Demand Forecast (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.		11.1.3 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.		Figure 7.8 CEI South Peak Load (MW) Alternative Scenarios
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.		6.2 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.		6 Resource Options; 8 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.		6.2 Current Resource Mix; 6.3 Potential Future Options Modeling Assumptions
(7) The resource screening analysis and resource summary table required by section 7 of this rule.		8.1.3 Portfolio Screening; Figure 11.36 New Construction Alternatives
(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.		8.1 Portfolio Development
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(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.		10 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.		List of Acronyms/Abbreviations with Definitions; 2 CEI South's IRP Process; 3 Public Participation Process; 4 Customer Energy Needs; 6 Resource Options; 7 Model Inputs and Assumptions; 8 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 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;		12 Technical Appendix Attachments

(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.		6.2.4 Energy Efficiency; 11.1.1 Forecast Inputs; 12 Technical Appendix Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(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.		11.1.1.4 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.		1.3.3.1 Advanced Metering Infrastructure (AMI)
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).		1.3.13 Contemporary Issues
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.		4.4 Customer Owned Distributed Energy Resources
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.		4.3 Model Framework; 7.1 Resource Model (EnCompass)
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.		9.1.7 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.		11.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.		8.1 Portfolio Development; 8.1.2 Scenario-Based and Deterministic Portfolios; 8.1.3 Portfolio Screening
(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.		1.3.2 Environmental Rules; 7.2. Reference Case Scenario; 7.3 Alternate Scenarios
(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.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(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. (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		7.2 Reference Case Scenario

(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.		7.3 Alternate 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.		6.4 Transmission Considerations
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.		4.3 Model Framework; 7.1 Resource Model (EnCompass); 6.3.2 DSM, 4.6 Energy and Demand Forecast (Reference Case); 6 Resource Options; 7 Model Inputs and Assumptions; 8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio; 12 Technical Appendix Attachments 1.1, 4.1, 6.2, and 8.2
(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:		11.3.4 Avoided Costs

(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.		
(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.		3 Public Participation Process
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.		6 Resource Options
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: (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.		11.1.3.2 Load Shapes; 12 Technical Appendix Attachments Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report; Attachment 4.2 CEI South Hourly Load Data
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.		11.1.3 Overview of Past Forecasts; 12 Technical Appendix Attachments Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(3) Actual and weather normalized energy and demand levels.		11.1.3 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.		11.1.3 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.		4.6 Energy and Demand Forecast (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.		11.1.3 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.		12 Technical Appendix Attachments 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(8) Justification for the selected forecasting methodology.		12 Technical appendix attachments 4.1 2022/2023 CEI South Long-Term Electric Energy and 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.		1.3.3.1 Advanced Metering Infrastructure; 11.1.2 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.		7.3 Alternate Scenarios
(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.		4 Customer Energy Needs; 7.3 Alternate Scenarios; 12 Technical Appendix Attachments 4.1 2022/2023 CEI South Long-Term Electric Energy and 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.		6.2 Current Resource Mix; 11.4.2 Approximate Net and Gross Dependable Capacity
(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.		6.2 Current Resource Mix
(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.		12 Technical Appendix Attachments: Confidential Attachment 8.2 EnCompass Input/Output Model Files
(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.		11.2 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.		11.7 Transmission Appendix

(C) An evaluation of the potential impact of demand-side resources on the transmission network.		
(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.		6.2.4 Energy Efficiency; 6.2.5 Demand Response; 6.3.2 DSM; 11.3 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.		6.3.2.7 Other 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. (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.		6.3.2 DSM; 12 Technical Appendix Attachments 6.2 2022 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 nondispatchable 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.		6 Resource Options; 11.2 Environmental Appendix; 12 Technical Appendix Attachments: Attachment 1.2 CEI South Technology Assessment Summary Table; Confidential Attachment 8.2 EnCompass Input Model Files

(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.		
(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 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.		6.4 Transmission Considerations
	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.		8.1.3 Portfolio Screening; Figure 11.36 New Construction Alternatives
	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.		2.5 Portfolio Development; 8 Portfolio Development and Evaluation

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.		
(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 kilowatt-hour delivered, with the interest rate specified.		8.2 Evaluation of Portfolio Performance; 9.1.2 Affordability; 11.6.8 Affordability Ranking
(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.		2.3.2.1 Reliability; 6 Resource Options; 8 Portfolio Development and Evaluation; 9.1 Preferred Portfolio Recommendation
(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.		9.1 IRP Preferred Portfolio Recommendation

(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.		N/A
(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.		9. IRP Preferred Portfolio; 10.2.5 Ability to Finance the Preferred Portfolio, 11.3.5 Avoided Costs, 11.6.7 Affordability Ranking; 12 Technical Appendix Attachments, Confidential Attachment 8.2 EnCompass Input/Output Model Files
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.		2 CEI South's IRP Process; 5 The MISO Market; 7.2 Reference Case Scenario; 7.3 Alternate Scenarios; 8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio; Confidential Attachment 8.2 EnCompass Input/Output Model Files
(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.		10.2 Discussion of Plans for the Next 3 years; 11.1.2 Load Forecast Continuous Improvement
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following:		8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio

(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.		
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.		10 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.		10 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.		10 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.		10.2.2 DSM
(3) The implementation schedule for the preferred resource portfolio.		10.3 Implementation Schedule for the Preferred Resource Portfolio
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.		10.2 Discussion of Plans for the Next 3 Years; Confidential Attachment 8.2 EnCompass Input/Output Model Files
(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.		10.1 Differences Between the Last Short Term Action Plan from What Transpired

List of Acronyms/Abbreviations

1898 & Co.	1898 & Co., a part of Burns & McDonnell
ABB	Power Consulting Company
ABB	A.B. Brown Generating Station
AC	Alternating Current
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ATC	Around the Clock
AUPC	Average Use Per Customer
BAGS	Broadway Avenue Generating Station
BAU	Business as Usual
BES	Bulk Electric System
BEV	Battery Electric Vehicles
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CHP	Combined Heat and Power
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CONE	Cost of New Entry
COVID	Corona Virus Disease
CPCN	Certificate of Public Convenience and Necessity
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
C&I	Commercial and Industrial
DC	Direct Current
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control
DLOL	Direct Loss of Load
DPP	Definitive Planning Phase
DR	Demand Response

List of Acronyms/Abbreviations (Cont.)

DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
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
ESP	Electrostatic Precipitator
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
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GPS	Global Positioning System
GS	General Service
GW	Gigawatt
GWh	Gigawatt Hour
HB	House Bill
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
Hg	Mercury
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
ILB	Illinois Basin
IMPA	Indiana Municipal Power Agency
Ind	Indiana
IRA	Inflation Reduction Act

List of Acronyms/Abbreviations (Cont.)

IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LDES	Long Duration Energy Storage
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
MATS	Mercury and Air Toxics Standards
MEEA	Midwest Energy Efficiency Alliance
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NIPSCO	Northern Indiana Public Service Company
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
NRIS	Network Resource Integration Service

List of Acronyms/Abbreviations (Cont.)

NTG	Net to Gross
NU	Network Upgrade
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PTC	Production Tax Credit
PV	Photovoltaic
RAN	Resource Availability and Need
Res	Residential
RF	ReliabilityFirst
RFP	Request for Proposals
RIIA	Renewable Integration Impact Assessment
RIM	Ratepayer Impact Measure
RS	Residential
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SBS	Sodium Based Sorbents
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SEA	Senate Enrolled Act
SERC	Southeast Reliability Corporation
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

List of Acronyms/Abbreviations (Cont.)

TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TRC	Total Resource Cost
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
V	Volt
VAR	Volt-Amp Reactance
VER	Variable Energy Resources
VFD	Variable Frequency Drive
WN	Weather Normalized

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Executive Summary (Non-Technical Summary)

I. Introduction

Southern Indiana Gas and Electric Company d/b/a CEI South a CenterPoint Energy Company's ("CEI South") 2022/2023 Integrated Resource Plan 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 recent orders related to the preferred portfolio described in CEI South's previous 2019/2020 Integrated Resource Plan ("IRP") both in the preparation of this IRP and the planning process that necessarily preceded the report. The analysis and its conclusions explained in this IRP demonstrate that CEI South can most cost-effectively meet the electric demands of its retail customers by continuing to transition its generation fleet from primarily coal-based generation to a generation mix that is much more diverse. The analysis demonstrates that customers receive a better balance of affordability and reliability by investing in new generation resources and transitioning existing resources to new fuel sources compared to the on-going necessary investment and future cost risk of continuing to run its existing coal-fired generation facilities.

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. The preferred portfolio in CEI South's previous 2019/2020 IRP concluded a generation transition was needed, calling for replacement of the majority of CEI South's coal fleet by the end of 2023 with 700-1,000 MWs of solar, 300 MWs of wind, energy efficiency and two gas combustion turbines while retaining FB Culley 3 coal resource. CEI South has begun implementing this 2019/2020 IRP by filing several cases seeking approval to (1) purchase a BTA to own and operate a 191 MW solar project located on its system (the "Posey County Solar Project"), (2) purchase a BTA to own and operate a 130 MW solar project located in Pike County (the "Crosstrack Solar Project"), (3) purchase a BTA to own and operate a 200 MW wind project located in MISO ("Midcontinent Independent System Operator") zone 4 (the "Wind Project"), (4) signed purchase power agreements ("PPA")

for 3 solar facilities totaling 430 MWs for the Warrick County Solar Project, the Knox County Solar Project, and the Vermillion County Solar project. (5) CEI South sought and received approval for two combustion gas turbines at A.B. Brown power plant, totaling 460 MWs. Each of these projects were consistent with the 2019/2020 IRP and, as noted below, this IRP affirms the direction taken by CEI South.

The Commission approved issuance of certificates of public convenience and necessity ("CPCNs") authorizing the construction of the Posey Solar Project and Cross Track Solar Projects and approved the solar PPAs. Government action and market forces have necessitated renegotiation of several of the renewable projects and delayed their in-service dates. CEI South has worked with the project developers to obtain revised pricing and in-service dates and has sought IURC approval of the changes for the Posey County, the Knox County, the Vermillion County, and the Warrick County Solar Projects. CEI South could have refused to work with the developers of these projects, but the poor economics would have resulted in the developers terminating their relationship with CEI South. Responses to CEI South's recent request for proposal demonstrated replacement projects would have been higher cost and brought later in-service dates. This is a significant concern for CEI South and its customers due to looming compliance deadlines for its existing generation resources. As of the date of this IRP, the IURC approved increased cost for the Knox County Solar Project, and the OUCC did not oppose the cost increases for the Warrick County Solar Project or the Vermillion County Solar Project. The Posey Solar Project and the Wind Project are awaiting approval by the IURC.

CEI South began its 2022/2023 IRP process in early 2022 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 2019/2020 IRP framework as a basis for the 2022/2023 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- increased stakeholder engagement in the issuance of an All-Source RFP to provide current market project pricing to be utilized in IRP modeling and potential projects to pursue, particularly for renewable resources such as wind, solar, and battery storage;
- increased participation and collaboration from stakeholders using tech-to-tech calls and associated file sharing throughout the process for timely feedback on inputs and resource evaluation criteria;
- an encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends, including MISO's new seasonal construct, which includes four seasons;
- at stakeholder request, CEI South engaged 1898 & Co. to utilize a new sophisticated IRP modeling tool, Encompass, which provided several benefits (increased transparency for stakeholders, more efficient modeling runs and maintaining the ability to produce probabilistic modeling); and
- a robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures with additional sensitivity analyses.

Based on this planning process and detailed analysis, CEI South has selected a preferred portfolio plan that continues to diversify the resource mix for its generation portfolio. This portfolio includes the addition of significant solar and wind energy resources in the near to midterm, the conversion of FB Culley 3 from coal to natural gas by 2027, and continued investment in energy efficiency and demand response resources. The conversion of Culley Unit 3 allows CEI South to maintain this critical capacity resource, protecting customers from a volatile MISO capacity market and considerably lowering CO_2 emissions. FB Culley 3 will be available for peak periods, enabling CEI South to maintain constant electric supply during potentially extended periods of low output from renewable energy sources. The converted unit will include firm gas supply and allow CEI South to continue to utilize existing equipment and interconnection to the MISO system. Additionally, CEI South has placed an emphasis on exploring demand response options

to provide a cost effective capacity resource for our customers. The company is in discussions with a demand response ("DR") aggregator for commercial and industrial DR and plans to request a pilot in its upcoming rate case to explore time based rates. Indicative DR amounts were included for IRP planning purposes. CEI South's preferred portfolio is projected to save customers nearly $80 million over the next 20 years compared to continuing with this last existing coal unit operated by CEI South. This builds on savings identified in the last IRP. Additionally, the preferred portfolio reduces carbon dioxide stack emissions by approximately 88% by 2030 and 95% by 2035 when compared to projected 2023 levels. This fosters environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

CEI South's preferred resource plan reduces risk through continued diversification, 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) Converts CEI South's last remaining coal unit that it operates to natural gas by 2027. This saves customers money and dramatically lowers CO_2 output in the near term. FB Culley 3 can also provide resilient, dispatchable power to CEI South's system during long-duration weather events. Reliable, dispatchable power is very important as coal plants that have provided capacity in the past continue to retire in MISO Zone 6. 2) Energy supplied by this portfolio is generated primarily through renewable solar and wind projects by 2030, which can take advantage of Investment Tax Credits ("ITC") and the Production Tax Credits ("PTC"). ITCs and PTCs reduce portfolio costs and leverage current tax-advantaged assets. 3) The portfolio provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio also performed well under CO_2, methane constraints, and other related regulations. Like the CTs identified in the 2019/2020 IRP, the preferred portfolio is financially supported by a converted coal unit that will predominantly run during peak load conditions. This benefit provides a financial hedge against periodic instances of high market energy and MISO's volatile capacity market, while also providing reactive reserves

and system reliability in times of extended renewable generation droughts, i.e., cloud cover and low wind. 4) It reasonably balances energy sales and purchases, ready to adapt to market shifts. 5) It includes new wind, solar, and demand response capacity when it is economic to the portfolio. 6) Finally, it is timely. The conversion of F.B. Culley 3 is projected to take no more than 6 months and can be completed by 2027.

The resource options selected in this plan provide a bridge to the future. For example, the gas conversion allows battery storage technology to become more competitive in price and develop longer duration storage capabilities. Further, should there be a need for new baseload generation to accommodate a large load addition, one or both of the new CTs could be converted to a combined cycle gas turbine, a highly efficient energy resource.

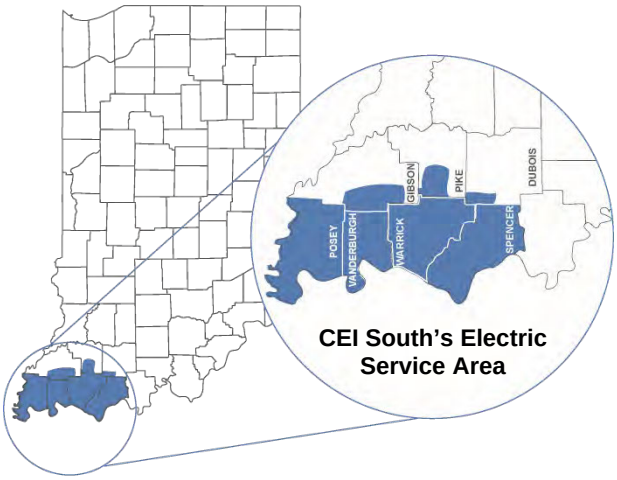
The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) CEI South plans to discontinue joint operations of Warrick 4 ("W4") at the end of 2023 but continues to speak with Alcoa about a possible extension into 2025. This option could shield CEI South customers from costly purchases in a tight capacity market. As CEI South has worked through the generation transition plan, solar project Commercial Operation Dates ("COD") have shifted, and there is still a need for capacity to complete phase one of the transition. Additionally, beyond delayed solar projects, time may still be needed for permitting contingency and construction of new combustion turbines, currently expected to be in service in MISO's 2025/2026 planning period. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio provides CEI South flexibility to evaluate this option in future IRPs. 3) CEI South will work to secure attractive renewable projects from the recent All-Source RFP and will likely require future RFPs to secure 200 MWs of additional wind and 200 MWs of additional solar resources by 2030. Issuing a future RFP provides two main benefits. It will provide the most up-to-date pricing for these renewables projects and attract more renewable options to select from, as some offered proposals are no longer available. Second, it provides CEI South additional time to better understand how the Inflation Reduction Act ("IRA") effects the

renewables markets, potentially unlocking more projects. Demand for wind and solar projects in Indiana is particularly high, which could lead to scarcity of projects if more potential developments do not enter the MISO queue.

The following 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.

II. CenterPoint Energy Overview

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in Southwestern Indiana. In 2022, approximately 43% of electric sales were made to large (primarily industrial) customers, 31% were made to residential customers and 26% 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	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date	Unit Age	Coal Unit Environmental Controls[1]
A.B. Brown 1	245	Coal	1979	2023	44	Yes
A.B. Brown 2	240	Coal	1986	2023	37	Yes
F.B. Culley 2	90	Coal	1966	2025	57	Yes
F.B. Culley 3	270	Coal	1973	N/A	50	Yes
Warrick 4	150	Coal	1970	2023[2]	53	Yes
A.B. Brown 3	80	Gas	1991	N/A	31	

[1] All coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_x"), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("$H2S0_4$") except F.B. Culley 2.
[2] Joint operations agreement expires 12/31/23

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date	Unit Age	Coal Unit Environmental Controls[1]
A.B. Brown 4	80	Gas	2002	N/A	21	
A.B. Brown 5	245	Gas	2025	N/A	N/A	
A.B. Brown 6	245	Gas	2025	N/A	N/A	
Blackfoot[3]	3	Landfill Gas	2009	N/A	14	
Fowler Ridge	50	Wind PPA	2010	N/A	13	
Benton County	30	Wind PPA	2007	N/A	16	
Oak Hill[4]	2	Solar	2018	N/A	5	
Volkman Rd[5]	2	Solar	2018	N/A	5	
Troy	50	Solar	2021	N/A	2	
Rustic Hills II Solar[6]	100	Solar	2025	N/A	N/A	
Posey Solar	191	Solar	2025	N/A	N/A	
Wheatland Solar[7]	150	Solar	2024	N/A	N/A	
Vermillion Rise Solar[8]	185	Solar	2025	N/A	N/A	
Crosstrack Solar	130	Solar	2025	N/A	N/A	
Future Wind	200	Wind	2025	N/A	N/A	

III. Integrated Resource Plan

Every three years CEI South submits an IRP to the IURC as required by IURC rules. The IRP describes the analysis process used to evaluate the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, affordable, environmentally sustainable power over the next 20 years. The IRP can be thought of as a compass setting 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 and environmental advocacy groups. CEI South continues to place an emphasis

[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.
[6] Warrick County Solar Project
[7] Knox County Solar Project
[8] Vermillion County Solar Project

on reliability, affordability, resiliency, stability, risk, resource diversity, and environmental sustainability. The IRP process has become increasingly complex in nature as MISO implements updated resource accreditation methodologies 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.

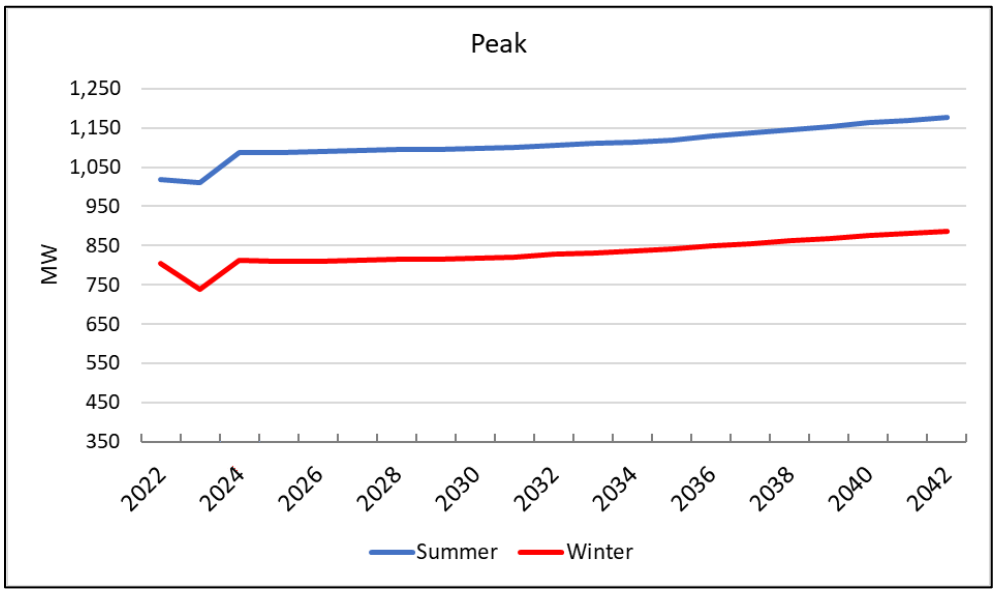
A. Customer Energy Needs

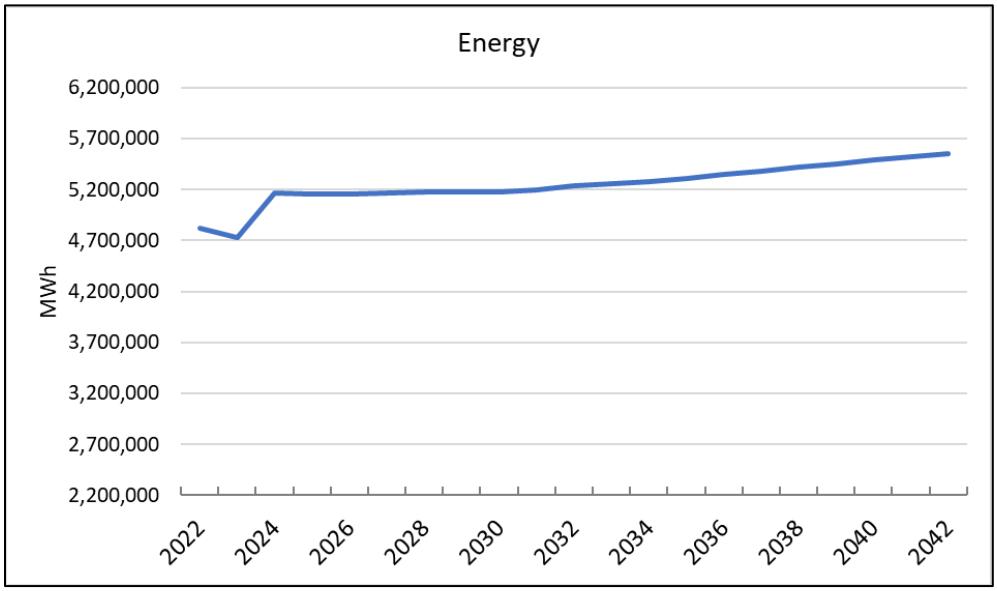
The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Energy is typically measured in Megawatt hours ("MWh") and demand is typically measured in Megawatts ("MW"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation and energy efficiency 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.

Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure resources are available to meet this demand seasonally in all hours of the year, particularly in the times of greatest need (summer and winter). MISO functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). In recognition of MISO's ongoing evaluation of how changes in the future resource mix impact seasonal reliability, CEI South ensured its preferred portfolio would have adequate reserve margins for meeting demand in all four seasons, consistent with MISO's recently

approved seasonal construct beginning in the 2023/2024 planning year on June 1, 2023. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability, beyond the seasonal construct.

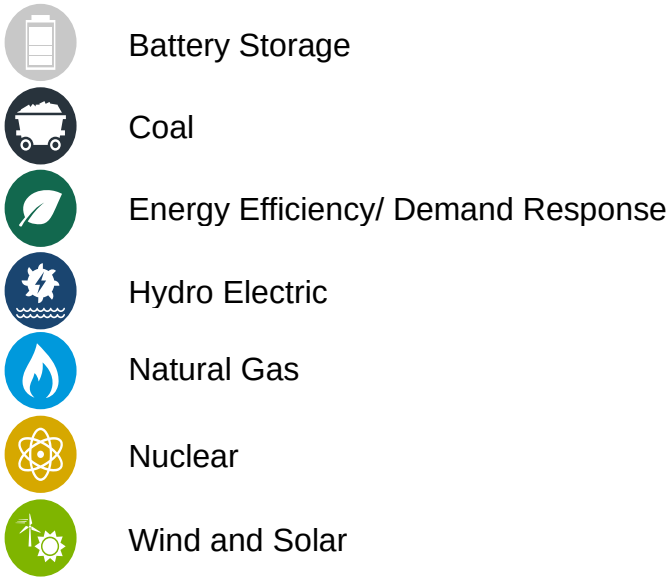
CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, 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 0.7% per year. Winter peak demand grows at a slightly slower pace of 0.5%.





B. Resource Options

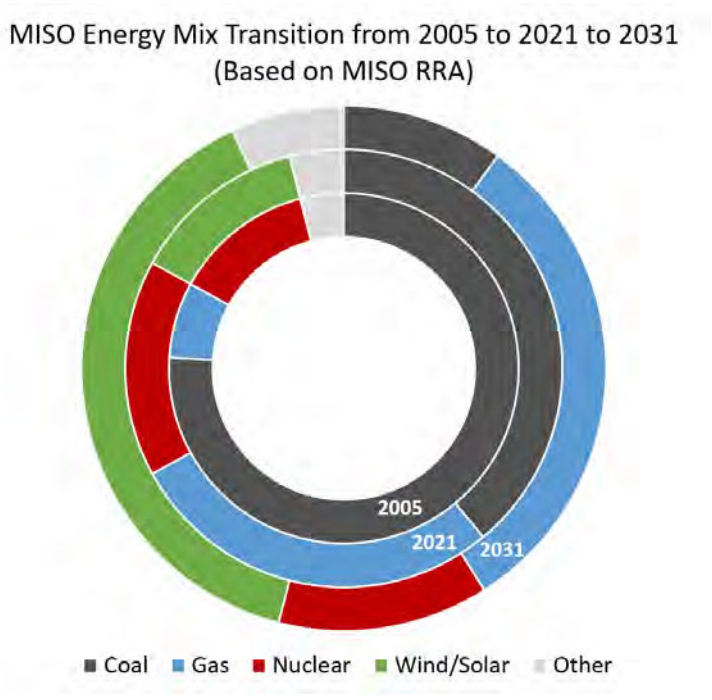
The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 142 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, demand response, wind, gas, nuclear, and coal. These project bids provided up-to-date, market-based information to inform the analysis and provide actionable projects to pursue to meet customer needs in the near to midterm. 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 2 and/or 3 coal units to natural gas, various other natural gas resources, conversion of AB Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries[9]. Every IRP is a snapshot in time producing a direction based on the best information known at the time. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the passage of the IRA, recent volatile gas prices, high inflation, projected high penetration of intermittent renewable resources, recent increased costs for renewables projects due to demand / supply chain issues, the future of coal resources with more restrictive air regulations, new technologies, and rapid changes in the MISO market to adapt and help ensure reliability.

i. Industry Transition

Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation, used primarily to meet the needs during peak demand conditions in 2005, to approximately 28% of total generation in 2021[10]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by



[9] Not commercially viable at this time
[10] MISO 2021 State of the Market Report, Potomac Economics, June 2022, page 6
https://cdn.misoenergy.org/2021%20State%20of%20the%20Market%20Report625295.pdf

government incentives in the forms of the PTC and the ITC for renewable energy resources such as wind and solar, both of which have been extended and expanded by the IRA.

The move toward renewable 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. Additionally, older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with Environmental Protection Agency ("EPA") regulations. Two recent rule changes are further examples of the continued pressure on coal. EPA finalized revisions to the Cross-State Air Pollution Rule and the Good Neighbor Rule which require further reductions in emissions of NOx during the Ozone Season. EPA has also recently proposed revisions to the Mercury Air Toxics rule that could further ratchet down particulates for F.B. Culley by 2026-2027and on January 6, 2023 EPA proposed a new rulemaking to reduce the National Ambient Air Quality Standard PM2.5 standard and review state's attainment designations. It can be challenging for F.B. Culley to maintain compliance under current regulations and will be more difficult to continue operating the unit on coal in 2027 and beyond. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has driven unit retirements. Based on these and other major factors, according to MISO's Regional Resource Assessment, they project wind and solar to contribute up to 42% of the energy in 2031[11]. Some large nuclear plants remain but have also found it challenging to compete on cost.

[11] MISO 2022 Regional Resource Assessment, November 2022, page 6
https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf

ii. Changing Market Rules to Help Ensure Reliability

MISO recognizes these 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 over production (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 resource portfolio and the risks MISO faces there is an increased importance of ensuring there are adequate attributes available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained with the changing resource portfolio, MISO implemented a seasonal resource adequacy construct for 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 ("$EFOR_d$") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources has also seen changes with MISO signaling it will continue to revise the accreditation approach for renewables for upcoming planning years. MISO continues to study how this transition will affect the electrical grid and what is needed to maintain reliable service, as renewables penetrations reach 30-50%. Possible ramifications

include challenges to the ability to maintain acceptable voltage and thermal limits on the grid.

CEI South has accounted for these changes by incorporating the seasonal construct and accreditation approach into the Encompass model and validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[12] 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 for each option.

iii. Battery Storage and Transmission Resources

Increasingly, utilities are considering the opportunity to add battery storage to resource portfolios to help provide the availability, flexibility and visibility to support the move to more reliance on intermittent renewable resources. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature and as the auto industry creates economies of scale by increasing production to meet the anticipated demand for electric vehicles. However, L-ion batteries continue to evolve. Lithium-ion batteries relying on iron-based cathodes are emerging and are expected to provide nearly 50% of the global demand by 2027. This move is occurring because of the relative abundance and sourcing of iron compared to Cobalt. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives are available to lower the cost of this emerging technology or for special applications that improve the economics. This technology will continue to evolve over the next decade as competing alternatives are put into operation and evaluated.

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

[12] Some portfolios have a heavy reliance on the market for energy.

the reliability of the transmission system. CEI South has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project has provided information regarding the ability to store energy for use during the evening hours to meet customer energy demand. Along with the benefits provided by this technology, there are some limitations to keep in mind as utility scale battery storage is still evolving. Commercially feasible batteries remain short duration, typically four hours. There are some longer-duration batteries that show promise, such as iron air, but these are still very expensive and not proven on a utility-scale. Future IRPs will continue to monitor for when these technologies become commercially viable. Additionally, safety standards are being developed and fire departments are being trained for the fire risk posed by L-ion batteries. Other chemistries are being developed to account for this issue but are not commercially imminent. Moreover, batteries today are a net energy draw on the system. L-ion can produce about 85-95 percent of the energy that is stored in them. Part of this loss is due to the need to be well ventilated, cool and dry, which takes energy. Batteries are promising and have their place in current and future energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Recent MISO changes in rules and mechanisms are geared towards meeting the worst week in each season. There is a need for multi-day storage to provide similar benefits to dispatchable generation. Other issues to be followed are how the penetration will affect accreditation based on Effective Load Carrying Capability ("ELCC"), which is expected to go down over time. CEI South conducted a sensitivity analysis to evaluate the cost impact of decreasing accreditation to 75% from 95%. The sensitivity demonstrated that cost to portfolios that rely on batteries would go up as accreditation goes down. Additionally, availability of batteries may not be 95% as modeled within this IRP. Information from California's experience suggests performance of batteries could be much lower. CEI South's All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources and will continue to track developments in this space.

C. Uncertainty/Risk

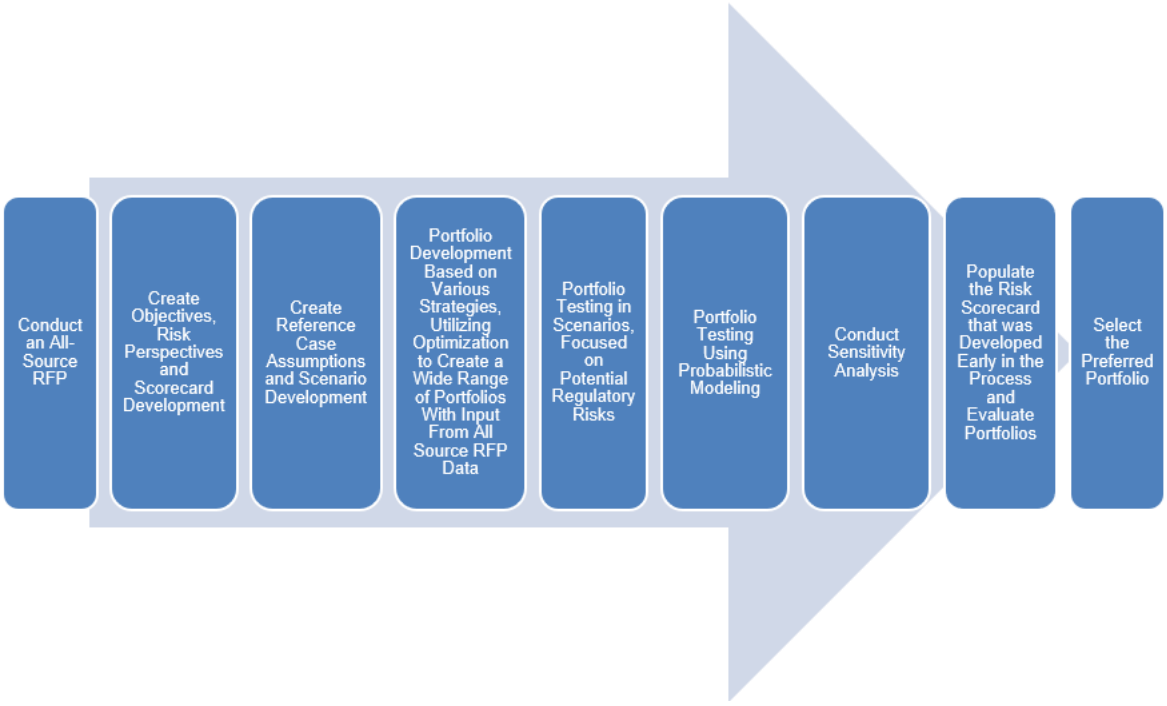
The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the best resource mix of generation and energy efficiency 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.

IV. 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. Conduct an All-Source RFP to better understand resource cost and availability.
2. Work 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. Work 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. Work 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. Conduct a risk analysis, including deterministic and probabilistic modeling with sensitivity analysis.

6. Utilize 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).



V. Stakeholder Process

CEI South continued to improve stakeholder engagement with a series of technical meetings with any stakeholder group willing to sign a Non-Disclosure Agreement ("NDA") and participate with in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. The process was reevaluated based on early feedback with stakeholders about what has worked well with other utilities throughout the state. CEI South also reviewed comments in the Director's report on CEI South's last IRP and ongoing Contemporary Issues meetings hosted by the IURC. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.

As in the last IRP, each of the first three stakeholder meetings began with stakeholder feedback. CEI South would review requests/comments since the last stakeholder meeting and provide feedback. Suggestions were taken, and in instances where suggestions were

not acted upon, CEI South made a point to further discuss and explain 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 one off phone calls/meetings in between each public stakeholder meeting by request, in addition to tech-to-tech meetings mentioned above.

While maintaining the virtual option to participate, CEI South thought it was important to offer face to face meetings post the COVID-19 situation of recent years. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to Southern Indiana or did not wish to participate in person. Dates and topics covered are listed below:

August 18, 2022	October 11, 2022	December 13, 2022	April 26, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs*	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

*Provided final draft modeling file on December 20, 2022 to stakeholders that signed an NDA as part of the tech-to-tech group. Final deterministic modeling files were provided on March 7, 2023, and final stochastic files were provided on April 21, 2023.

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 along the way 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. CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding a metric that highlights risk from exposure to energy generated by coal and gas, and adopting a metric that measures total CO_2 equivalent tons emitted into the atmosphere over the full planning year. Finally, multiple adjustments were made to modeling inputs and assumptions based on direct stakeholder feedback. The table below shows key stakeholder requests made during the process and CEI South's response.

Request	Response
Allow All-Source RFP respondents to update their proposals to account for the IRA	RFP respondents were given the opportunity to update their bids (updated results were incorporated into the IRP)
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	Cumulative CO_2 equivalent (stack emissions) were added to the scorecard along with CO_2 intensity
Add a fuel cost risk measure and objective to the scorecard	Cost Risk metric was included in the scorecard, including both fuel risk and 95% percentile cost risk

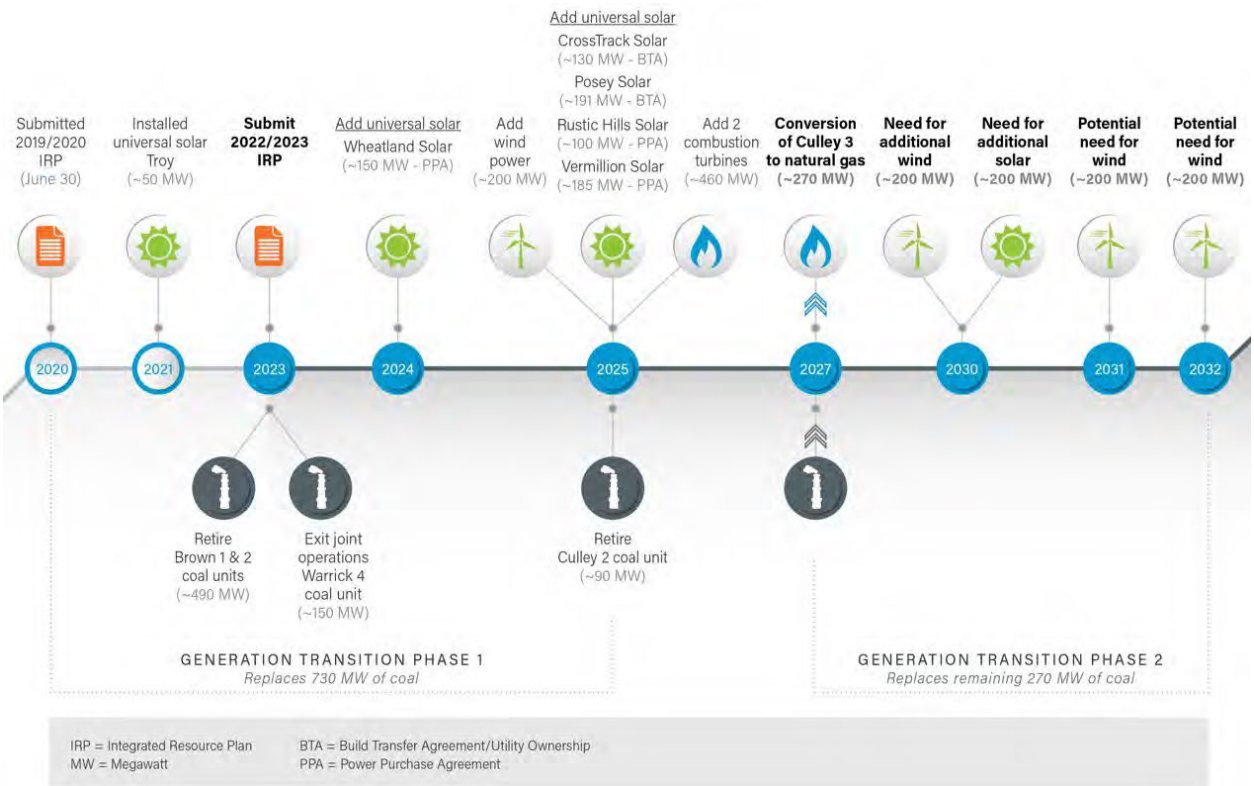
Request	Response
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South included 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR registered with MISO. CEI South is engaged in conversations with a demand response aggregator to capture the potential of C&I demand response to further diversify our resource mix
CenterPoint should include demand response using the same methodology as AES. Implement residential rate programs (critical peak pricing, TOU, etc.) soon	CenterPoint has adopted the AES methodology and DR is aligned with peers to incorporate indicative TOU pilots. CEI South is planning to evaluate a TOU rate in the future through a pilot
In the summer of 2022, the reference case forecasts for coal and natural gas prices showed a decline in the near term and do not reflect current pricing	Gas and coal price forecasts were updated as new forecasts became available in late fall of 2022
Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	CEI South found it plausible that coal prices could be higher in a high regulatory scenario and updated the price path to be higher than reference case in the high regulatory scenario
Revise the wind profiles being used in the model to differentiate between the output of northern Indiana and southern Indiana wind	The output profiles for wind resources were updated (increased) to better align with the information received from wind resources in the All-Source RFP

Request	Response
Explore alternative retirement dates for Culley 3	Culley 3 will be evaluated in scenarios with a potential retirement date of 2029 (pulled forward from 2030). Also included an alternative that converts F.B. Culley 3 to natural gas by 2027
Update modeling to reflect ITC storage year one	CEI South modeled the ITC benefit for storage in year one
Include full monetization of ITC for hydro resources	Included
Request for continued on-going dialogue following the December public stakeholder meeting	Held a tech-to-tech meeting on February 28, 2023 to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment
Include site -specific assumptions for the energy community bonus for PTC and ITC associated with the IRA	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions
Evaluate a portfolio with hydroelectric	Hydroelectric was not selected as a least cost resource within modeling. Several portfolios with hydro were evaluated, but they were higher cost and not included in the risk analysis
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

Meeting materials for each meeting can be found on www.centerpointenergy.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

VI. The Preferred Portfolio

The Preferred Portfolio is the second evolution to the generation transition plan to move away from coal to a more sustainable portfolio of resources. The recommendation is to convert the remaining 270 MWs of coal generation to natural gas and to provide demand response resources for low-cost capacity and continue to add clean, renewable wind and solar resources by 2030, while maintaining energy efficiency programs at similar levels. Beyond 2030, 400 MWs of additional wind is called for.

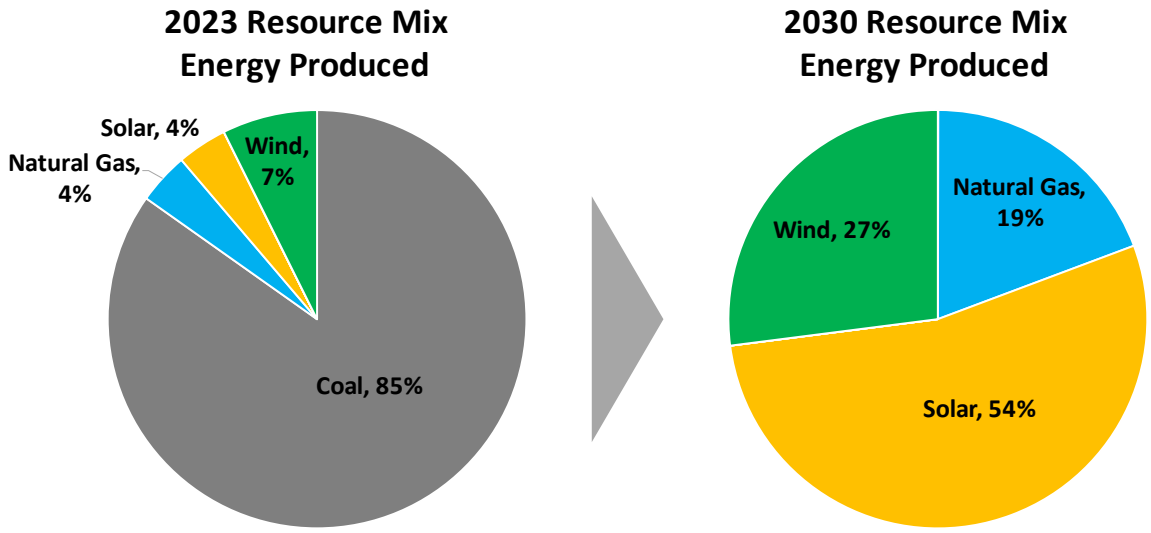


This preferred portfolio:

- Eliminates dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future.
- Maintains reliability and allows customers to enjoy the benefits of renewable energy, while ensuring continued reliable service as CEI South continues to move toward higher levels of intermittent renewable energy in the future. Dispatchable generation with firm gas service at F.B. Culley will allow this resource to be available to meet peak conditions during long duration weather events, providing resiliency.
- Saves customers nearly $80 million over the next 20 years when compared to continued operation of F.B. Culley with coal and avoids $170 million of cost risk over this time period. Eliminates risk of additional cost to comply with currently proposed final environmental rules that become applicable to Culley 3 in 2027 and potential new regulations as EPA continues to focus on environmental concerns associated with coal-fired generation.
- Reduces CO_2 equivalent emissions, which includes methane, by nearly 95% over the next 20 years. Direct carbon emissions are reduced 98% from 2005 levels by 2035. The portfolio prevents over 9 million tons of CO_2 from entering the atmosphere as compared to continuing to run F.B. Culley 3 with coal.
- Includes a diverse mix of resources (solar, wind and energy efficiency, supported by fast-start gas, peaking gas generation, and demand response), mitigates the impacts of extended periods of limited renewable generation and protects against overreliance on the market for energy and capacity.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry, includes a multi-year build out of resources on several sites and maintains the option to replace Culley 3 in the future when appropriate based on continual evaluation of available technology and changing conditions.
- Provides the flexibility to adapt to future environmental regulations or upward shifts in fuel prices relative to Reference Case assumptions. The preferred portfolio

performed consistently well across a wide range of potential future environmental regulations, including CO_2, methane and fracking.

- 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 potential future stranded assets.
- Continues CEI South's energy efficiency programs with near term energy savings of 1.1% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. 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.
- Explores new options to help manage loads in the future with the potential for new demand response resources, working with an aggregator to better partner with commercial and industrial customers to tap additional potential and include a pilot to evaluate the potential of time-based rates, which could provide new resources to help manage loads in the future.



VII. Next Steps

The preferred portfolio calls for CEI South to make additional changes to its generation fleet. Some of these changes require action in the near term. First, CEI South will seek approval from the IURC to convert F.B. Culley 3 from coal to natural gas. Second, the IRP calls for continuation of energy efficiency. CEI South filed a one year continuation of the 2021-2023 plan for 2024 and will file a 2025-2027 plan in early 2024 with the IURC, consistent with the IRP. Third, CEI South plans to issue a new RFP in 2024 to pursue an additional 200 MWs of wind generation and 200 MWs of solar generation to be in service by 2030. CEI South continues to evaluate the potential to work with industrial customers who would like on-site solar generation. CEI South will evaluate including a portion of the new solar for this purpose. Given the long lead times for these projects and the need for energy that they produce, CEI South will begin pursuing these renewable projects ahead of the next IRP. These filings will be consistent with the preferred portfolio. 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 plan.

CEI South's plan must be flexible, as several items are not certain at this time.

- The timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa and as such, CEI South continues to talk to Alcoa about its plans.
- Competition for renewable projects is steep, with multiple, ongoing RFP processes in the state of Indiana and the passage of the IRA. CEI South will continue to actively seek cost competitive projects for the benefit of our customers, consistent with the preferred portfolio.
- Finally, MISO continues to evaluate the accreditation of resources. CEI South will continue to follow developments.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

CEI South is an indirect subsidiary of CenterPoint Energy, Inc. On February 1, 2019, CenterPoint Energy, Inc. (NYSE: CNP) and Vectren Corporation (NYSE: VVC) completed a merger. CenterPoint Energy is headquartered in Houston, has regulated electric businesses serving 2.8 million metered customers in the greater Houston area and in Southwest Indiana and natural gas utility businesses in six states that serve more than 4 million homes and businesses.

Operation of CEI South's electric transmission and distribution services, including its power generation and wholesale power operations now fall into CEI South. CEI South serves more than 150,000 customers in Southern Indiana.

1.2 INTEGRATED RESOURCE PLANNING

CEI South takes integrated resource planning very seriously. The IRP is used as a guide for how CEI South will serve existing and future customers over the next 20 years in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and Demand Side Management ("DSM") options. It is not a turn-by-turn GPS. 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 2020 with a plan to transition its generation fleet away from a majority reliance on coal to a diversified portfolio of renewable generation, complimented by quick start, fast ramping natural gas combustion turbines. CEI South began this IRP process by gathering feedback from stakeholders on the last IRP and the Final Director's Report for the 2019/2020 Integrated Resource Plan. 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 Chapter 3 Public Participation Process.

The future is uncertain; several factors have helped to set the stage for this analysis. Multiple, rapid changes engulfed the world, effecting energy and capacity markets following the COVID stay at home orders. The threat of tariffs, an investigation by the US Commerce Department on forced labor in China, and supply chain issues stemming from the lockdowns all worked to greatly increase solar costs and delay projects across the country. Simultaneously, natural gas prices become more volatile with the war in Ukraine, going up in the summer of 2022 to levels not seen in years. With increased natural gas prices and rampant inflation, electricity prices soared in 2022. Additionally, MISO market capacity prices reached Cost of New Entry ("CONE") for the 2022/2023 planning year across MISO's North and Central regions, earlier than expected. Capacity shortages are still projected as capacity rich resources are retired for intermittent, renewable resources.

MISO continues to make changes to ensure reliability of the system. MISO has been actively updating rules and mechanisms to ensure reliability as we evolve toward a more complex, less predictable future. MISO foresees a shift towards primarily weather dependent resources, less predictable resource outages or unavailability, less predictable weather, scarcity of essential reliability attributes, and increasing load. All have led MISO to plan for providing energy for the worst week in each season verses the traditional approach, which is to plan for resources to meet load during the peak hour of the year, typically in the summer across the Midwest. To deal with these challenges, MISO has implemented and continues to implement changes and has shifted focus to resources that have the following priority system attributes: availability, fuel assurance, ramp capability, long duration energy at high output, rapid start-up, and voltage stability.

Based on expectations of increasing penetration of renewables, particularly solar, MISO, CEI South's regional transmission operator, continues to evaluate rules and mechanisms that are needed now and in the future to maintain reliability. CEI South continues to monitor developments within MISO; the outcomes of several strategic studies are important for resource planning. 1) MISO completed a Renewable Integration Impact Assessment ("RIIA"), a rigorous analysis that evaluated increasing amounts of wind and

solar resources on the Eastern Interconnection bulk electric system, with a focus on the MISO footprint over the long term. This assessment demonstrated that as renewable energy penetration increases, so does the magnitude of the bulk electric system need and risk. The results show that MISO will undergo required transformational change in planning, markets, and operations. 2) MISO published the Resource Availability and Need ("RAN") whitepaper, where MISO describes the reliability imperative and the need to align the availability, flexibility and visibility of both supply and demand resulting in reliable and efficient operations every hour of the year. 3) The Reliability Imperative is a "living" report that prioritizes MISO's interconnected initiatives that addresses the region's challenges within four pillars Market Redefinition, Transmission Evolution, System Enhancements, and Operations of the Future. The Market Redefinition pillar takes a granular look at the planning and accreditation of a changing resource mix, more frequent extreme weather events and the shifting needs and challenges of ensuring sufficient resources during high-risk periods. 4) MISO's Annual Regional Resource Assessment ("RRA") provides a collective view of how members' resource plans are evolving, revealing key insights and implications that can inform the work that members, states, and MISO are doing to balance reliability, affordability, and sustainability priorities. One such insight showed that as the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three to four times between 2031 and 2041 compared to current levels. This prompted MISO to launch an initiative to identify system reliability attributes that, under current market constructs, could become scarce due to the region's rapidly evolving mix of generation.

Per stakeholder request, CEI South chose to move away from the Aurora modeling platform to a more transparent tool, EnCompass. It maintains essential tools needed to conduct an IRP, while providing more transparency, greater speed of results, and greater flexibility. The output from this model provides quantitative data to help evaluate portfolios within a robust risk analysis designed to understand performance over a wide range of futures. A great benefit of the tool is that CEI South was able to model MISO's seasonal construct and quickly make changes to account for MISO's rapid evolution.

1.2.1 IRP Objectives

CEI South's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[13] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, sustainable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, CEI South's objectives are as follows:

- Safe Reliable Service (a requirement for all portfolios)
- Affordability (reflected in the balanced scorecard)
- Environmental Risk Minimization (reflected in the balanced scorecard)
- Cost Uncertainty Risk Minimization (reflected in the balanced scorecard)
- Avoiding Overreliance on Market Risk for capacity and energy (reflected in the balanced scorecard)
- Future Flexibility (reflected in both offramps and "other considerations")
- Resource Diversity (reflected in "other considerations")
- System Flexibility (operational flexibility to support renewable resources)

1.2.2 IRP Development

CEI South continues to incorporate feedback from IRP stakeholders and IURC staff. Specific feedback was incorporated into the 2022/2023 IRP process. First, CEI South incorporated feedback directly into its All-Source RFP, discussed further in chapter 3. As in the last IRP, CEI South made several commitments to IRP stakeholders to maintain improvements from prior IRPs and to strengthen the analysis with new improvement opportunities, most notably with the introduction of tech-to-tech meetings throughout the process and increased file/data sharing at multiple points in the process. This allowed stakeholders to review modeling inputs, model settings, and outputs in real time during the analysis. CEI South is appreciative to stakeholders who took time to review this information in detail and provide timely feedback. This setting allowed for more productive

[13] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

conversations and allowed for sharing of confidential information with those that signed an NDA.

CEI South worked closely with industry experts to develop a comprehensive analysis. 1898, a Burns & McDonnell Company, ("1898", "1898 and Company", or "1898 & Co.") managed all aspects of the All-Source RFP. This analysis was utilized to provide current market pricing for resources and an opportunity for CEI South to pursue individual projects to help serve CEI South customers following the conclusion of the IRP. 1898 & Co. also worked with CEI South to conduct scenario development, modeling and a comprehensive risk analysis, which included both scenario based and probabilistic modeling. CEI South also worked with GDS to convert Market Potential Study outputs into IRP inputs, and 1898 modeled these demand side resources on a consistent and comparable basis with supply side resources.

1.3 CHANGES SINCE THE 2019-2020 IRP

Several developments have occurred since the last IRP was submitted in June 2020, which help to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information at a point in time. The following sections discuss some of the major changes that have occurred over the last three years. CEI South realizes conditions will change, and this analysis was designed to test portfolios under a wide range of plausible futures.

1.3.1 Generation

1.3.1.1 Generation Transition Plan

CEI South has begun implementing this 2019/2020 IRP by filing several cases seeking approval to (1) purchase a BTA to own and operate a 191 MW solar project located on its system (the "Posey County Solar Project"), (2) purchase a BTA to own and operate a 130 MW solar project located in Pike County (the "Crosstrack Solar Project"), (3) purchase a BTA to own and operate a 200 MW wind project located in MISO zone 4 (the

"Wind Project"), (4) signed purchase power agreements ("PPA") for 3 solar facilities totaling 430 MWs for the Warrick County Solar Project, the Knox County Solar Project, and the Vermillion County Solar project. (5) CEI South sought and received approval for two combustion gas turbines at A.B. Brown power plant, totaling 460 MWs. Each of these projects were consistent with the 2019/2020 IRP.

The Commission approved issuance of Certificates of Public Convenience and Necessity ("CPCNs") authorizing the construction of the Posey Solar Project and Cross Track Solar Projects and approved the solar PPAs. Government action and market forces have necessitated renegotiation of several of the renewable projects and delayed their in-service dates. CEI South has worked with the project developers to obtain revised pricing and in-service dates and has sought IURC approval of the changes for the Posey County, the Knox County, the Vermillion County, and the Warrick County Solar Projects. CEI South could have refused to work with the developers of these projects, but the poor economics would have resulted in the developers terminating their relationship with CEI South. Responses to CEI South's recent request for proposal demonstrated replacement projects would have been higher cost and brought later in-service dates. This is a significant concern for CEI South and its customers due to looming compliance deadlines for its existing generation resources. As of the date of this IRP, the IURC approved increased cost for the Knox County Solar Project, and the Office of Utility Consumer Counselor ("OUCC") did not oppose the cost increases for the Warrick County Solar Project or the Vermillion County Solar Project. The Posey Solar Project and the Wind Project are awaiting approval by the IURC.

1.3.1.2 FERC 2222

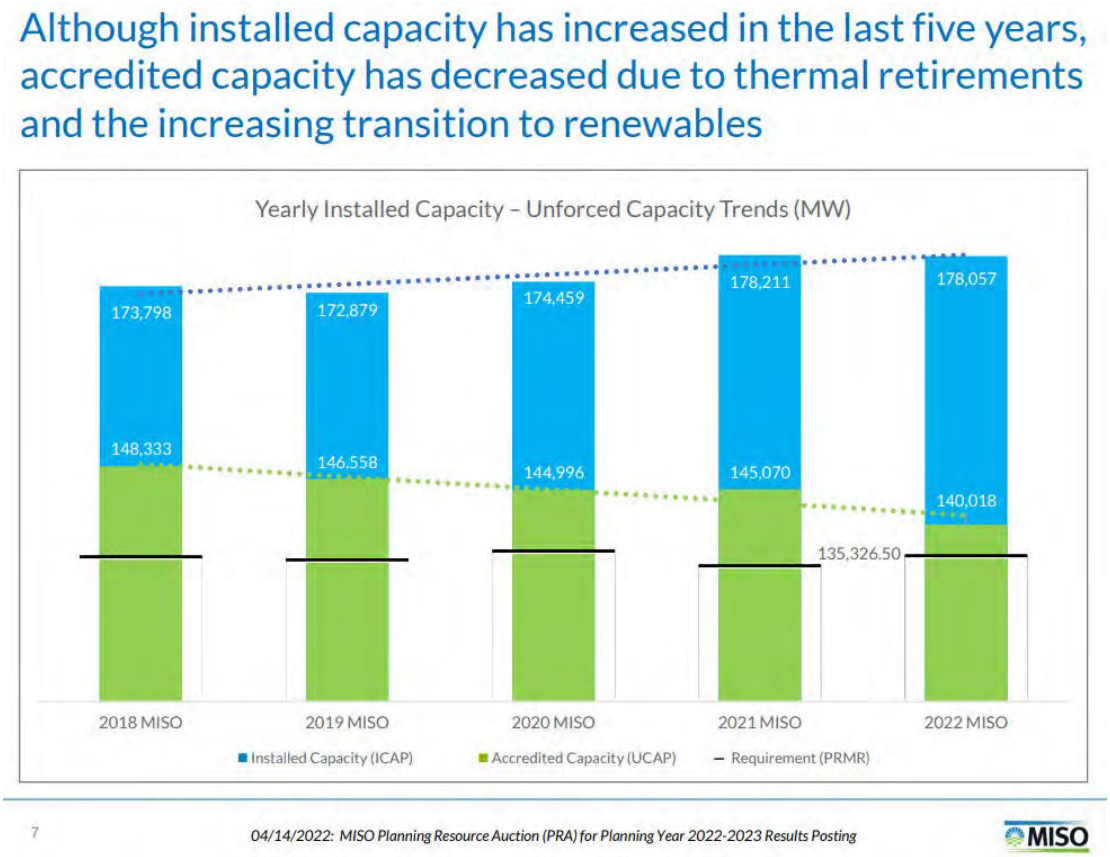
FERC Order No. 2222 instructs Regional Transmission Operators ("RTO") and Independent System Operators ("ISO"), like MISO, to allow for Distributed Energy Resource ("DER") aggregations to participate directly in the wholesale markets and establish a new category of market participants. A DER is considered any resource located on the distribution system, any subsystem thereof or behind a customer meter.

These resources include, but are not limited to demand response, behind the meter generation (renewable or thermal), electric vehicles or energy efficiency. FERC issued the order on September 17, 2020, which required RTOs/ISOs to submit compliance filings outlining their implementation plans and effective dates for DER market participation. MISO has proposed to permit DER aggregations participation in the MISO Market starting in 2030. The Indiana Commission has initiated an investigation into how this order will affect resource planning. It will require unprecedented coordination among regulators, market participants, MISO, and utilities to ensure a smooth transition. It is too soon to fully foresee all the implications for resource planning.

1.3.1.3 MISO Capacity Market

For the 2022-2023 planning year MISO's north and central regions experienced a capacity shortfall resulting in all of these local resource zones to clear at CONE ("Cost of New Entry"), which is the maximum clearing price and was a significant increase over historical auction results. MISO noted that there is a growing gap between the accredited capacity of retiring thermal resources and the accredited capacity of new intermittent resources coming online. Figure 1.1 below illustrates how this gap has grown from 2018-2022.

Figure 1.1 MISO Accredited and Installed Capacity[14]



At the time MISO noted that unless more capacity is built that can supply reliable generation, shortfalls highlighted in the 2022-2023 auction will continue.

In the 2023-2024 seasonal planning resource auction clearing prices dropped when compared to the 2033-2023 auction with an average seasonal clearing price around $10/MW-Day in MISO's North/Central region. This decrease is auction clearing price could be temporary if retirements outpace the installation of new capacity. MISO's continued resource adequacy reforms, particularly accreditation reforms, could also impact the amount of capacity available to meet the systems reserve requirements resulting in an increase in the clearing price of future auctions.

[14] MISO 2023/2023 PRA Results – April 14, 2022; Page 7
https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf

1.3.1.4 Alcoa Contract

Alcoa and CEI South have jointly owned and operated the 300 MW Warrick 4 unit since 1970. It is still CEI South's intention to exit the Joint Operating Agreement ("JOA") for CEI South's share of Warrick Unit 4 at the end of the contract term, December 31, 2023; however, discussions with Alcoa related to the possible extension of the JOA beyond the contract term are ongoing. While continuing to speak to Alcoa about Warrick 4 options, the working assumption is this IRP is that Warrick 4 will no longer be in CEI South's fleet by the end of the contract.

1.3.1.5 Solar Energy Tariff, Sanctions and Supply Chain Issues

China is a major producer of solar panels and other solar products. Certain solar cells, modules, laminates, and panels from China are subject to various antidumping and countervailing duty rates, depending on the exporter supplying the product, imposed by the U.S. government as a result of determinations the United States was materially injured as a result of such imports being sold at less than fair value and subsidized by the Chinese government.

In March 2022, the Department of Commerce ("DOC") announced it would initiate an investigation into whether imports of solar cells and panels produced in Cambodia, Malaysia, Thailand and Vietnam ("CMVT") are circumventing U.S. rules and laws, such as antidumping and countervailing duty rates, which impose a tariff on imports of solar cells and panels manufactured in China.

In June 2022, the Biden Administration announced a two-year tariff exemption period for solar energy imports from the CMTV countries. In the context of the Auxin inquiry, this means that if the DOC concluded China was using manufacturers in the CMTV countries to evade U.S. trade regulations, entries of covered products from those manufacturers would be eligible for a waiver of the otherwise applicable anti-circumvention tariffs until at least June 5, 2024.

In December 2022, the DOC issued its preliminary findings noting that circumvention was occurring in each of the four countries. If an affirmative finding is made by the DOC, it could impose duties on imports of solar cells and panels from CMVT with both forward-looking and retroactive application.

In addition, in December 2021, President Biden signed into law the Uyghur Forced Labor Prevention Act, which bans goods from China's Xinjiang region due to the use of forced labor.

Lastly, continuing tensions between the United States and China may lead to restrictions in trade between the two countries or new legislation, tariffs or bans, any of which could further negatively impact the supply of solar panels. These or similar duties and legislation have and may in the future also put upward pressure on prices of these solar energy products, which may reduce our ability to acquire these items in a timely and cost-efficient manner.

1.3.1.6 MISO Resource Adequacy Changes

Historically, MISO's approach to resource adequacy has focused on ensuring that sufficient resources would be available when demand peaks in the summer with the expectation that serving load the rest of the year would be comparatively easier. But given the increase in MaxGen emergencies in recent years in non-summer seasons, MISO evaluated several traits of their current construct such as the granularity, risk metrics, Planning Resource Auction ("PRA") auction design, reliability requirement, and market signals. Their evaluation developed into an extensive stakeholder process that ultimately concluded with MISO filing tariff changes to Federal Energy Regulatory Commission ("FERC"). The proposed changes included a seasonal resource adequacy construct to address significant increases in emergency events that occur year-round, driven by factors including generation retirements, reliance on intermittent resources, outages resulting from extreme weather events, and declining excess reserve margin along with

a proposal to implement seasonal, availability-based accreditation ("SAC") to establish capacity values for thermal and demand response resources.

1.3.1.7 Implementation of Approved MISO Seasonal Construct and Accreditation

The MISO region is transitioning from a generation portfolio dominated by coal and nuclear resources to a portfolio that increasingly relies on intermittent and emergency-only resources. Generation retirements are accelerating this transition and have caused MISO to operate with decreasing capacity margins.

As a result of the evolving resource fleet, MISO determined that its resource adequacy mechanism fell short of supporting reliability in all hours of the year. The identified deficiencies include: (1) mechanisms did not incent members to add their resources and required capabilities to the resource pool; and (2) the current reserve margin analysis did not adequately reflect variations in resource production and other seasonal risk factors. On November 30, 2021, (in Docket No. ER22-495-000) MISO made a filing with FERC to address these issues through proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff. MISO filed amendments to its proposal on April 8, 2022. On August 31, 2022, FERC issued an Order accepting MISO's tariff revisions subject to condition. On September 29, 2022, MISO submitted a compliance filing pursuant to FERC's Order. On September 30, 2022, several parties timely sought rehearing of FERC's Order; those requests were deemed denied by operation of law on October 31, 2022.

MISO's proposal included a sub-annual resource adequacy construct consisting of four separate seasonal reserve margin targets and capacity auctions to better reflect variation in capacity accreditation and capacity needs across the year. The construct is premised on four three-month seasons. Each season accounts for special attributes, such as winter weatherization and applies the capacity resource must-offer requirement to only the seasons for which the capacity resource is cleared to allow units to be operated seasonally. MISO will also simultaneously conduct four separate seasonal analyses to

reflect transfer limits between its resource-adequacy zones. In addition, MISO revised its loss-of-load expectation analysis to model more accurately seasonally sensitive variables.

MISO also proposed to revise its resource accreditation to reflect real-time availability and seasonal performance of generation assets to mitigate reliability risks while improving coordination of planned outages. The revised accreditation process includes a two-tiered weighting approach to emphasize availability during "tight" critical need periods (Tier 2) but also general availability in "non-tight" hours (Tier 1). Resources that are not online during critical need periods are penalized if their lead time exceeds 24 hours. Regardless of the tier, coordinated outages are fully exempt from penalty if (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage start date and certain projected Maintenance Margin levels are met; and (2) the generator owner or operator reschedules its planned outage at MISO's request due to certain enumerated conditions. In addition, partial outage-related exemptions are available under certain circumstances for time periods outside of "highest need."

The approved tariff changes were implemented beginning with the 2023/2024 Planning Year and are a component of the next phase of MISO's ongoing RAN initiative.

1.3.2 Environmental Rules

1.3.2.1 Rules Update

1.3.2.1.1 Air

Periodic updates to air emission regulations under the Clean Air Act continue to challenge the daily operations of coal-fired electric generating units. Over time emission limits have gotten lower, emission averaging times have gotten shorter, and allowance pools have been significantly restricted, presenting increasing challenges to maintaining consistently high levels of compliance. These compliance challenges are further exacerbated as these units are called upon to cycle in lieu of baseload operation.

1.3.2.1.1.1 Cross-State Air Pollution Rule and "Good Neighbor" Rule

Since our previous IRP the US Environmental Protection Agency ("EPA") has finalized revisions to several regulations under the Clean Air Act that imposed more stringent requirements and make coal fired EGUs increasingly difficult and costly to operate. The most recent CSAPR Update Rule was published in the Federal Register on April 30, 2021 and became effective June 29, 2021. This final rule reduced emissions of nitrogen oxides ("NOx") from power plants in 12 states, which included Indiana. As part of the implementation of that rule, EPA adjusted those states' emissions budgets for ozone season, beginning with the 2021 ozone season. The impact to A.B. Brown and F.B Culley was a nearly 20% reduction in allocated allowances for the 2021 ozone season. The ozone season NOx allowance allocation total for A.B. Brown, F.B. Culley, and Warrick 4 for 2020 was 1,355. The allocation was reduced to 1,167 for the 2021 ozone season, and for the 2022 ozone season it was further reduced to 851. CEI South made significant efforts to reduce NOx emissions, however still had to purchase costly allowances to make up for the difference. Moreover, the recently signed Good Neighbor rule has added 11 states to Group 3, and while the allocations to CEI South facilities are primarily unchanged, the addition of 11 states to Group 3 coupled with an annual recalibration of the emissions allowance bank based upon retiring units has the potential to continue impacting the cost of allowances in the market. Additionally, the regulation has a "backstop" NOx emission rate that may be more stringent than the current rates at F.B. Culley when considering the rule proposes a daily rate versus the current 30-day rolling average in place for Culley, in which case Culley could have to surrender seasonal NOx allowances at a ratio of 3-for-1. This backstop would first apply in the 2024 ozone season. A further backstop requirement could require utilities to operate Selective Catalytic Reduction ("SCRs") at a higher efficiency level, even if ozone season NOx allowances are available.

1.3.2.1.1.2 Mercury and Air Toxics Standards Rule ("MATS")

EPA has proposed to strengthen and update the MATS rule for coal-fired power plants by proposing more stringent emissions limits and additional monitoring and control methods based upon its risk and technology review. As proposed, the rule would significantly reduce the emission limit for particulate matter ("PM") from 0.03 lb/mmBTU to 0.010 lb/mmBTU, and EPA is taking comment on an even lower PM emission rate.

1.3.2.1.1.3 Fine Particulate NAAQS

In addition to the proposed revisions to PM emission limits in MATS EPA has also proposed to lower the National Ambient Air Quality Standards ("NAAQS") primary annual PM2.5 level from 12.0 µg/m3 to within the range of 9.0 to 10.0 µg/m3. EPA also requested comments on an alternative standard of annual PM2.5 values 8.0 or 11 µg/m3 and a 24-hour NAAQS value of 25 ug/m3. After the regulation is finalized, air quality for individual counties will be assessed and designated as either in attainment or nonattainment for meeting the new standard. A nonattainment designation would require a state implementation plan to improve air quality and could add additional costs to operate the coal-fired Electric Generating Units ("EGU") under a reduced standard.

1.3.2.1.1.4 Greenhouse Gas Regulations

EPA finalized the Affordable Clean Energy rule ("ACE") repealing and replacing the Clean Power Plan in June 2019. The ACE rule established carbon dioxide ("CO_2") emission guidelines for states to use when developing plans to limit CO_2 at coal-fired EGUs within the state. ACE established heat rate improvement, or efficiency improvement, as the Best System of Emissions Reductions ("BSER") for CO_2 from coal-fired EGUs. States were given six candidate technologies to be considered as BSER along with their calculated efficiency improvements and costs to implement and operate. States are to establish unit-specific standards of performance that reflect the emission limitation achievable through

application of the BSER technologies with consideration of “the remaining useful life of the source” and other source-specific factors. State Implementation Plans are due April 2024 with compliance planned to begin within 24 months of submission. As the ACE Rule was in place during the current IRP modeling process, compliance with the Rule was modeled as a methodology to attribute a carbon cost to future operations.

On May 10, 2023, the EPA released a pre-publication version of a new set of proposed regulations under CAA Section 111 to address GHG emissions from new and modified EGUs. These new regulations would replace ACE. EPAs proposal presents an array of compliance requirements for different types of fossil-based units that would take effect at different times. Specifically, EPA is proposing to finalize new guidelines for states to regulate existing coal-fired EGUs under Section 111(d), new source performance standards for new natural gas-fired EGUs under Section 111(b), and guidelines for states to regulate existing natural gas-fired EGUs under Section 111(d). For coal-fired EGUs the proposal would set the best system of emission reductions as the use of carbon capture and sequestration, however the proposal provides off-ramps for units slated for retirement. For new and modified gas-fired units the proposal would establish a system of best management practices, efficiency targets and co-firing options depending upon the size and utilization of the units.

1.3.2.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (“ELG”). The rule sets strict technology-based limits for wastewaters generated from fossil fuel fired generating facilities and will force significant operational and technological changes at coal-fired power plants. EPA finalized the rule with a hybrid of the most stringent of the proposed options for fly ash transport water, bottom ash transport waters and Flue Gas Desulfurization (“FGD”) wastewaters.

While the 2015 final rule includes reference to multiple wastewaters, the key elements applicable to CEI South are FGD wastewaters and ash transport waters. Specifically, FGD wastewaters must meet new limits for arsenic, mercury, selenium, and nitrate / nitrite at the end of the wastewater treatment system and prior to mixing with any other process waters. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity, which effectively forces the installation of dry or closed loop ash handling systems. In September 2017, the ELG Postponement Rule was published. The Postponement Rule delayed the applicability date for the Bottom Ash Transport Waters ("BATW") from November 1, 2018 to November 1, 2020, but the no later than December 31, 2023 date for completion remained in place. In October 2020, the ELG Reconsideration Rule was published. The Reconsideration Rule changed the no later than date for discharge of Bottom Ash Transport Water from December 31, 2023 to December 31, 2025. It also provided an additional two years for FGD wastewater compliance, however CEI South was already committed to a Zero Liquid Discharge system under conditions of the F.B. Culley National Pollutant Discharge Elimination ("NPDES") permit, along with planning for eliminating waste streams in preparation for the closure of the East Ash Pond.

The A.B. Brown and F.B. Culley NPDES permits were renewed and became effective in early 2023. The F.B. Culley permit was modified as appropriate to allow for the BATW date extension allowed by the ELG Reconsideration Rule. As required by the ELG Rule and consequently the NPDES permits, F.B. Culley has ceased the discharge of Fly Ash Transport Water ("FATW") and completed the conversion of bottom ash on Unit 3 to a dry system in December 2020. For FGD wastewaters at F.B. Culley, alternate, but more restrictive limits were voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits included the installation of zero liquid discharge equipment that would eliminate all discharge of FGD wastewater. This technology went into service on May 1, 2023.

1.3.2.1.3 Waste

The Coal Combustion Residuals Rule ("CCR") was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The "Phase 1, Part 1" rule was published on July 30, 2018, and became effective on August 28, 2018. This rule delayed the deadline by which facilities must cease the placement of waste in a CCR surface impoundment in cases where the CCR unit fails to meet the aquifer location restriction and in cases where a CCR unit demonstrates an exceedance of a groundwater protection standard. The regulatory deadlines that currently present a scenario that could trigger the closure of CEI South surface impoundments include exceedance of ground water protection standards (triggering closure in October 2020), or failure to demonstrate compliance with location restrictions (triggering closure in October 2020). Environmental groups challenged the final "Phase 1, Part 1" rule in the D.C. Circuit Court. Additionally, in August 2018, the D. C. Circuit Court issued a decision in USWAG v. EPA, finding that the administrative record showed that all unlined impoundments pose a reasonable probability of adverse effects to human health and the environment and must be required to close. EPA filed a motion to remand the Phase 1, Part 1 rule and is currently working on rulemakings to implement the D.C. Circuit's decision. The "Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure" rule is one of those rulemakings and was finalized in August 2020. It provided an option for utilities to submit a demonstration (application) by November 30, 2020 for surface impoundments to remain active beyond the current rule closure dates, however no longer than October 15, 2023. CEI South submitted demonstrations for both the A.B. Brown Ash Pond and the F.B. Culley East Ash Pond. The A.B. Brown demonstration has been conditionally approved. The alternative capacity project is currently underway at A.B. Brown and has been completed at F.B. Culley.

1.3.2.2 Retrofitting Culley 3 to Comply with ELG

In accordance with the order of the IURC in Cause No. 45052 approving the planned activities necessary to continue to operate Culley 3 in compliance with the ELG and CCR rules, the bottom ash system at F.B. Culley Unit 3 conversion to a dry system was completed in December 2020. The FGD system was converted to Zero Liquid Discharge ("ZLD") technology. That project was completed and in service on May 1, 2023. These two technologies make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines ("ELG") rule and the NPDES permit requirements for Culley 3.

1.3.2.3 Closing Coal Ash Ponds

The West Ash Pond at F.B. Culley completed closure in December 2020. The closure design included the construction of a lined contact storm water pond, which receives contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies, along with the new lined pond currently under construction, will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure later this year. Plans are currently underway for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse. The project was approved in Cause No. 45280, and the ash removal of this pond is expected to take several years. New lined ponds are currently under construction and these ponds will receive waters that currently go to the ash pond but need to be re-routed for the pond closure.

The majority of the ash from the AB Brown ash pond will be sent to a facility that uses the ash to make Portland Cement. This project will take several years to totally remove all ash from the pond; however, once the closure begins the water in the pond will be drained down. There will be a small amount of ash in the pond that cannot be used for beneficial reuse, and it will be moved to an onsite landfill.

1.3.3 Electric Transmission Distribution Storage Improvement Charge

System improvements from CEI South's seven-year Transmission Distribution Storage Improvement Charge ("TDSIC") plan that have been made to build/rebuild high-voltage transmission lines, replace substation transformers, rebuild electric circuits, and build distribution automation will help CEI South to continue to reliably deliver power to its customers now and in the future. These improvements will allow more flexibility in resource planning by improving power flows across CEI South's system, particularly the addition of the East-West transmission line that connects the Warrick North substation site on the east side of the system with the A.B. Brown plant site on the west side. This project was energized on March 1, 2023. CEI South filed its second TDSIC plan on May 24, 2023, which outlines additional upgrades between 2024-2028[15]. An order is expected from the Commission by the end of the 2023.

1.3.3.1 Advanced Metering Infrastructure ("AMI")

In 2017, CEI South began installation of AMI smart meters as a key part of CEI South's grid modernization plan. CEI South has since successfully installed meters across its territory. AMI provides access to much more granular customer load data and will help CEI South to better understand and anticipate changes in an evolving energy landscape. This improvement will have long-term benefits for load research and long-term load forecasting, as well as provide the opportunity to create innovative DSM programs for shaping customer load. CEI South customers have already received many benefits in the near term for billing, quicker service response time, improved meter read accuracy, customer dashboards, proactive repairs reported by meter events, and quicker responses to power outages. CEI South has worked closely with its IT department to be able to pull customer demand data by rate class, starting with 2022, and now can segment on various customer groups. Over the next year, more tools will become available as CEI South's meter data management system is replaced with the meter data management system in Texas. At that time, CEI South will unlock more potential with out of the box applications

[15] Cause No. 45894

that have been created for the Houston territory. The ability to leverage functionality that has already been built will be a huge benefit to Southern Indiana; however, these long-term benefits have not been fully realized by the compilation of this IRP.

1.3.4 Inflation Reduction Act ("IRA")

The IRA was signed into law by President Biden on August 16, 2022. The timing of the IRA passage was fortunate, as it was in the early phase of this IRP and allowed for CEI South to quickly work to allow All-Source RFP bidders to resubmit their bids to incorporate the effects of the law change. The $500 billion bill aimed at reducing the effects of climate change included numerous incentives to promote investment in clean energy production and included tax credits for households to offset energy costs. Most of this spending is intended to reshape energy infrastructure. Major pieces of this bill that have helped shape this IRP include the extension of wind production tax credits, the allowance of solar production tax credits, the continuance of solar investment tax credits, funding for energy efficiency, the introduction of the ITC for stand-alone battery storage, and incentives for electric vehicle charging.

In addition to the base PTC and ITC there are several bonus adders and requirements that are possible to increase the value of these tax credits. The requirements or adders brought forward for projects under the new IRA include, but are not limited to, wage & apprenticeship requirements, domestic content minimums, siting in energy communities, and siting in low-income Communities or on Indian land. Since the passage of the IRA in August 2022, the IRS has been issuing clarifications and guidance on how projects can qualify for these adders. Since this is an ongoing process, CEI South included sensitivities to capture various uncertainties with future project tax credit qualifications.

1.3.5 DSM Filing

On June 3, 2020, CEI South filed with the IURC a Petition seeking approval of CEI South's 2021-2023 Energy Efficiency Plan ("2020-2023 Filed Plan" or "Plan"). The Plan included proposed energy efficiency goals; program budgets and costs; and procedures for independent Evaluation, Measurement and Verification ("EM&V") of programs included

in the Plan. The Plan has an estimated cost of $34.2 million, with $11.5 million in 2021, $11.3 million in 2022 and $11.3 million in 2023. The Plan includes a portfolio of programs designed to achieve 132 million kWh in energy savings and 29,935 KW in demand reduction during the three-year period.

On October 20, 2020, CEI South filed a joint stipulation and settlement agreement between CEI South, the OUCC, and Citizens Action Coalition ("CAC"). On February 3, 2021, the IURC issued an Order approving CEI South's 2021-2023 Energy Efficiency Settlement Agreement ("2021-2023 Approved EE Plan") pursuant to Section 10. CEI South carried out a lengthy analysis of the DSM resources included in its IRP process. The Commission found that the proposed energy savings goals appear reasonably achievable and consistent with historical savings that has been previously approved. A summary of the savings and budgets are listed in the table below.

Figure 1.2 – 2021-2023 Portfolio Summary of Participation, Impacts, & Budget

Portfolio Participation, Impacts & Budget[16]							
Program Year	**Participants / Measures**	**Annual Energy Savings kWh**	**Annual Demand Savings kW**	**Res & C&I Direct Program Budget**	**Indirect Portfolio Level Budget**	**Other Costs Budget**	**Portfolio Total Budget Including Indirect & Other**
2021	235,332	44,325,438	10,061	$10,061,209	$1,046,819	$400,000	$11,508,027
2022	225,146	43,961,753	9,571	$10,092,043	$1,051,408	$200,000	$11,343,451
2023	218,863	43,533,925	10,303	$10,073,357	$1,061,922	$200,000	$11,335,280

1.3.6 2019 IRP Director's Report

Each year, the Director of Research Policy and Planning in the IURC electric division issues a critique of IRPs. The 2019 IRP Director's report listed a balance of positive comments, coupled with improvement opportunities for CEI South. The table below shows the improvement opportunities with a brief description of how the comment was addressed within the 2022/2023 IRP:

[16] Cost per kWh excludes indirect and other costs for budget. Cost per kWh is calculated by dividing program cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs.

Figure 1.3 – IRP Improvements Based on 2019 IRP Director's Report[17]

Improvement Opportunities	Addressed
Break out energy efficiency bundles into C&I and residential bundles	CEI South broke out energy efficiency bundles into C&I and residential and worked closely with stakeholders to evaluate and apply the maximum amount of EE to be economically selected within modeling. Residential bundles were grouped according to high and low/medium costs so as not to exclude all residential from not being selected. C&I bundles included an enhanced bundle to optimize the selection of EE above realistic achievable potential. Stakeholder feedback was included and helped guide bundle development.
Future requests for proposal should consider all DER opportunities	DERs were able to participate in the RFP utilized for this IRP. As a result of opening the All-Source RFP more and based on stakeholder feedback, CEI South is actively engaged with a DR aggregator to explore the market potential of the Evansville area for C&I DR and to partner to tap into this market as a future resource.
One optimization run with a minimum number of constraints	During the IRP process, the Reference Case Portfolio was determined by an optimization run in EnCompass that included as few constraints as possible around resource selection. This allowed the model to run in an unconstrained way selecting the portfolio by determining tradeoffs between existing resource options and new resource selections.

[17] The director provided guidence on page 13 of the Director's Report for Vectren's 2019/2020 IRP on November 17, 2021, to consider sub-hourly modeling to capture value of ancillary services. Currently ancillary services provide a very small piece of revenue potential, and it is extremely difficult to accurately project the value in the future. The added complexity was not deemed necessary when compared to the value that the complex analysis would provide. CEI South will continue to monitor the need for this level of detail in the future as computer processing speeds increase. https://www.in.gov/iurc/files/Vectrens-Final-Directors-Report-November-17.pdf

1.3.7 HB 1007

On April 20, 2023 the Governor Holcomb signed HB 1007 into law; it becomes effective on July 1, 2023. The law requires decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs to take into account the following attributes: Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability. These attributes must be considered within the Directors' report for an IRP submitted by an electric utility. The IURC must also consider these attributes when acting upon a petition for the construction, purchase or lease of an electric generation facility, and when the IURC reviews whether a CPCN continues to require the completion of an electric generation facility under construction. As such, the law will help continue to shape Indiana's energy future. Importantly, the bill further reduces a utility's reliance on MISO's planning resource auction from 30% to 15% of its accredited capacity in the summer and winter. This was a major consideration within this IRP.

1.3.8 COVID-19

By the spring of 2020, Indiana, like many other states across the country, issued a "Stay at Home" order in response to the COVID-19 virus. This had the impact of significantly reducing commercial and industrial usage as businesses shutdown and residential usage significantly increased as work activity shifted from the office to the home. As these restrictions were lifted most businesses re-opened, although even today some portion of the workforce remains working from home. To capture the impact, the residential average use and non-residential rate class models include a COVID impact variable. This variable is constructed using Google Mobility Report data for the residential, workplace and retail place types for Vanderburgh County. Google Mobility Report data tracks daily cell phone locations by place type compared to a pre-COVID baseline. The residential place type active increased while the workplace and retail decreased, this data correlates well to the actual changes in electric sales.

1.3.9 Contemporary Issues

CEI South participates in the Commission's IRP Contemporary Issues Technical Conference held each year. The most recent Conference was held on September 22, 2022. The Conference covered topics such as MISO's new seasonal resource adequacy construct, PJM's resource adequacy model, the continued evolution of their resource mix and emerging reliability risks, and how reliability planning is evolving.

Several of these topics were timely and influential within CEI South's analysis. For example, the MISO seasonal construct presentation discussed priority system attributes needed to maintain system reliability. These attributes included long duration energy at high output, ramp capability, and fuel assurance, all of which are included in CEI South's preferred portfolio.

CEI South also participated in the IRP Contemporary Issues Technical Conference on July 15, 2021. During the conference GDS, our Market Potential Study ("MPS") partner, talked about similarities and differences in the market potential studies GDS conducted on behalf of the several Investor Owned Utilities ("IOU") in Indiana. It covered differences in how the load forecast is used in the MPS, how avoided costs and line loss assumptions were included in the analysis, the availability of market and measure characteristic data, inclusion of emerging tech and measure refill, and measure mapping to existing programs. GDS also touched on using the MPS to provide inputs into the IRP. CEI South also had internal staff speak to the role of Energy Efficiency Oversight Board in the development of IRP inputs, monitoring DSM program performance and how the OSB works collaboratively to provide input into measures offered, program design, and utilization of approved program dollars to achieve portfolio goals.

The discussion relating to All-Source RFPs during the September 24, 2020, Technical Conference was also beneficial as CEI South issued another All-Source RFP on May 11, 2022 to support this IRP analysis. CEI South engaged 1898 & Co., a subsidiary of Burns and McDonnell, to administer the RFP and serve as an independent evaluator. The All-

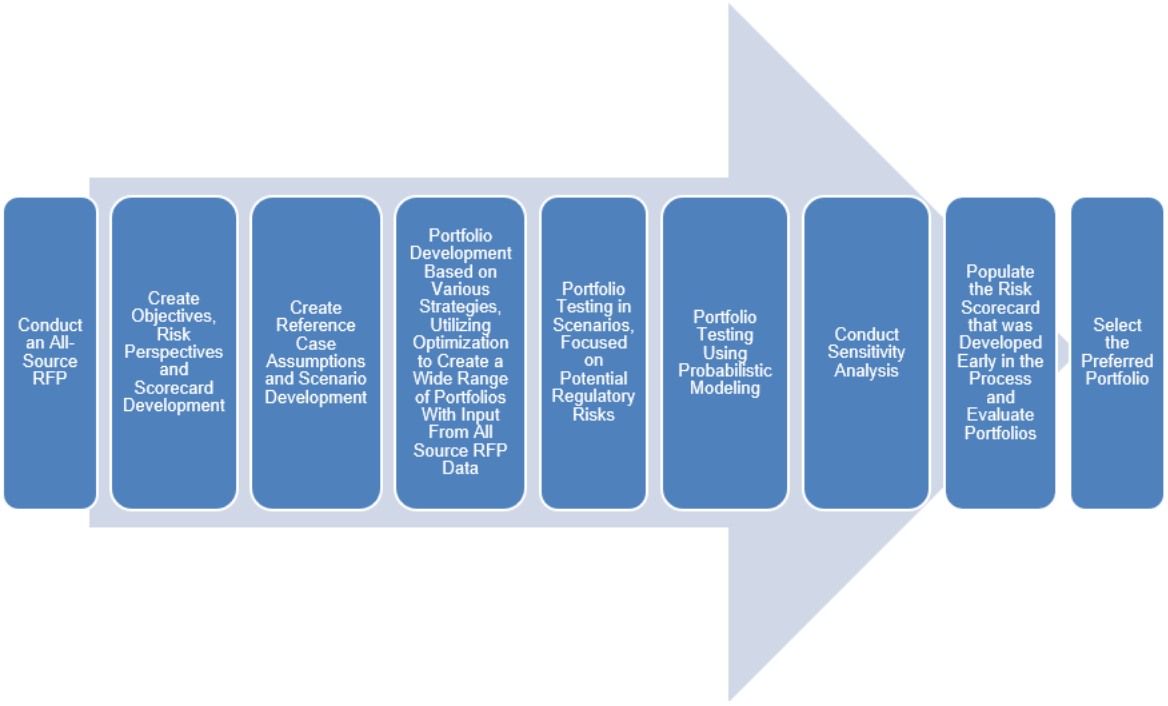
Source RFP was structured to be open and non-limiting and resulted in proposals largely comprised of solar, wind, battery storage, and Load Modifying Resource (“LMR”)/DR resources. The All-Source RFP is discussed in further detail in sections 3 and 6 of this report.

SECTION 2
CEI SOUTH'S IRP PROCESS

2.1 CEI SOUTH'S IRP PROCESS

CEI South's 2022/2023 IRP followed a very structured, comprehensive process over a 15-month period with extensive risk-based analysis and included an All-Source RFP to include market-based pricing with the opportunity to secure available resources following the conclusion of the IRP. This process was designed to ensure relevant technologies were evaluated and the resulting portfolio combinations were tested in a wide range of future market and regulatory conditions. The process followed is illustrated below.

Figure 2.1 – CEI South IRP Process



The following sections describe each step in the analysis.

2.2 Conduct an All-Source RFP

CEI South issued an All-Source Request for Proposals ("RFP") seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. Long term resource planning requires addressing risks and uncertainties

created by several factors including the costs associated with new resources. As part of ongoing resource planning, CEI South concluded that it was in the best interest of its customers to seek information regarding the potential to acquire, construct, or contract for additional capacity that qualifies as a MISO internal resource (i.e., not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service ("NRIS") to MISO LRZ 6. These requirements helped to provide price certainty, transparency, and MISO Local Clearing Requirement ("LCR") accreditation, which will be discussed in further detail.

Within the context of the 2022/2023 IRP process, CEI South used an All-Source RFP to solicit bids for supply-side and demand-side capacity resources. The purpose of the RFP was to identify viable resources available to CEI South in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources and prior to the 2022/2023 IRP, there was a potential capacity need of approximately 500 MW of accredited capacity depending on the different portfolios being studied as part of the IRP. CEI South sought flexibility when defining potential resource combinations and encouraged RFP respondents to offer available projects with less than, or more than, 500 MW. CEI South also considered alternative timelines related to the capacity acquisition to the extent Respondents were able to provide more competitive pricing and/or terms for delivery if the resource was in service or operational prior to 3/1/2027. CEI South used aggregated data from the RFP responses as inputs into the IRP modeling. The RFP Proposal evaluation process was based upon the specific resource needs identified through this IRP modeling as well as the Proposal evaluation criteria. Through this RFP, CEI South sought to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, LMRs/DRs, renewables, stand-alone and paired storage, and contractual arrangements.

In connection with this RFP, CEI South retained the services of an independent third-party consultant, 1898 & Co., part of Burns & McDonnell, to manage the entire RFP

process and work with CEI South to perform the quantitative and qualitative evaluations of all Proposals.

All Respondents were directed to interface with 1898 & Co. for all communications including questions, RFP clarification issues and RFP Proposal submittal until late in the evaluation process.

Proposals were initially reviewed for completeness by 1898 & Co. Respondents were contacted for additional data or clarifications by 1898 & Co. via a designated CEI South RFP e-mail address, centerpointrfp@1898andco.com. Each complete Proposal was evaluated based on the Levelized Cost of Energy ("LCOE"), energy settlement location, interconnection/development status & local clearing requirement and project risk factors. The evaluation criteria were intended to relatively compare each Proposal to analogous submissions. This evaluation, in conjunction with the IRP, was used to determine which combination of resources are most capable of providing CEI South customers with a safe, reliable, and affordable power supply.

2.3 OBJECTIVES, RISK PERSPECTIVES and SCORECARD DEVELOPMENT

CEI South's IRP process is designed to ensure a systematic and comprehensive planning analysis to determine the "preferred portfolio" that best meets all its objectives over a wide range of market futures. This process results in a reliable and efficient approach to securing future resources to meet the energy needs for CEI South customers.

In addition, the IRP process complies with environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions. In the IRP, CEI South also focused on increasing the diversification of its supply sources. As part of the IRP, CEI South considered maintaining flexibility to respond to market changes. The evaluation considered both existing and new resources, including renewable energy and battery storage options.

Economic modeling is an important part of the IRP process, as it allows CEI South to identify the portfolio of supply-side and demand-side resources on a competitive economic basis. The resulting portfolios reflect a combination of market, regulatory or technology specified conditions and market input parameters (for example, identify the least cost portfolio consisting of mostly renewables and battery storage by 2030 using reference case market forecasts). While cost is an important objective, it is by no means the only objective. CEI South has several important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Moreover, CEI South needs to account for operational and logistical considerations in the construction of alternative portfolios to ensure that they meet minimum reliability or resource adequacy considerations.

CEI South's IRP strategy is designed to accommodate ongoing changes and uncertainties in the market. CEI South's IRP objectives are based on the need for a resource strategy that provides long-term value to its customers and communities. Therefore, as objectives are evaluated, tradeoffs must be considered. Specifically, CEI South's IRP objectives are as follows:

- Reliability: As new technologies proliferate and older baseload units retire, it is apparent that there will be increased reliance on intermittent, renewable energy resources. The ability to support local system stability and reliably provide power must be maintained by meeting MISO and North American Electric Reliability Council ("NERC") standards for reserve margins and resource adequacy.

Quantitative Metrics Directly Considered

- **Affordability:** Provide all customers with an affordable supply of energy
- **Cost Uncertainty Risk Mitigation:** Provide a predictable, balanced, and diverse mix of energy resources designed to help ensure costs do not vary greatly across alternative future market conditions or supply disruptions.

- **Environmental Sustainability:** Provide environmentally responsible power, leading to a low carbon future with fewer impacts to air and water quality and less waste generated.
- **Market Risk Minimization:** Develop a flexible plan that can adapt to market conditions and regulatory and technological change to minimize risk to CEI South customers and shareholders. The plan considers several alternative options for existing resources.

Other Considerations

- **Execution:** Assess challenges with implementing the determined plan.
- **Resource Diversity:** Mitigate risk to customers of over-reliance on a single technology by providing a resource mix to minimize the dependence on any one resource type that could become operationally or economically eclipsed.
- **System Flexibility:** Operationally able to meet the current and future needs of the evolving grid.
- **Resilience:** A portfolios ability to recover from off normal events, like extreme/long duration weather events.
- **Stability:** The ability of a portfolio to maintain system frequency and voltage, thermal limits, and power transfer capability.

Reliability is CEI South's priority over all other objectives. All portfolios must meet minimum reserve margin and resource adequacy requirements set by MISO. These are minimum requirements met in the modeling rather than a single metric tracked for each portfolio. CEI South did a reliability assessment to identify mitigations needed for stability for several portfolios represented options that made it through the screening process. This is described in Section 6.4.3 Transmission Facilities as a Resource.

The next several objectives are given one or more defined and measurable metrics. By testing candidate portfolios against these metrics, CEI South illustrates tradeoffs among competing IRP objectives. This tool aided in the selection of the preferred portfolio. The last five objectives are more subjective in nature but relevant to the IRP process so are discussed under "other considerations".

Figure 2.2 – CEI South Scorecard for IRP Objectives and Risk Metrics

	Objective	Metric
Quantitative and Qualitative (considered outside of scorecard)	Reliability	• Must meet MISO planning reserve margin requirement in all seasons • Spinning reserve and fast start capability
Quantitative Scorecard Measure	Affordability	• Mean value for the 20-Year Net Present Value of Revenue Requirements ("NPVRR") (million$) across 200 dispatch iterations under varying market conditions
	Cost Uncertainty Risk Minimization	• 95th percentile[18] of NPVRR (million$) across 200 dispatch iterations under varying market conditions • Portion of energy generated by resources with exposure to coal and gas markets
	Environmental Sustainability	• CO_2 Intensity (Tons CO_2e/kwh) • CO_2 equivalent emissions (Tons CO_2e)
	Market Risk Minimization	• Energy Market Purchase and sales (%) • Capacity Market purchases and sales (%)
Qualitative (considered outside of scorecard)	Execution	• Assess challenges of implementing each portfolio
	Resiliency	• Assess the ability of a portfolio can recover from off normal events, like extreme/long duration weather
	Stability	• Assess ability of the portfolio to help maintain system frequency and voltage, thermal limits, and power transfer capability
	Resource Diversity	• No over reliance on any one resource or resource type
	System Flexibility	• Operationally able to meet the current and future needs of the evolving grid

[18] 95th percentile means that there is a 95% chance the cost falls below this level (only 5% chance above). Price Risk Minimization represents the upper end cost potential for the portfolio

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with low expected costs may increase exposure to market risk. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to help ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances. Portfolio selection is based on CEI South evaluating all qualitative and quantitative metrics and using well-informed judgement in selecting its preferred portfolio. A further description of each metric is provided below.

2.3.1 Objectives and Risk Perspectives

The IRP objectives were evaluated using the results of the scenario, sensitivity, and probabilistic modeling, as well as other qualitative factors.

2.3.2 Scorecard Metrics

The Balanced Scorecard is a broad comparison of candidate portfolio attributes and risks. It was populated with metrics nearly all derived from the probabilistic modeling. The probabilistic modeling subjected each portfolio to 200 iterations of the dispatch model under varying market conditions. CEI South then used the resulting performance data and the distributions from the 200 iterations to quantify the metrics that align with each IRP objective. The Balanced Scorecard metrics are the same as the risk metrics described in Figure 2.2.

2.3.2.1 Reliability

The ongoing energy transition is transforming the way IRPs are conducted, further emphasizing reliability considerations within an IRP process. As a member of MISO, CEI Couth is not independently responsible for all elements of reliability but must be prepared to meet changing market rules and standards. MISO has been studying the impacts of growing intermittent generation penetration in the market for the last several years, and where possible CEI South has incorporated those elements into the IRP. CEI South

ensured all portfolios considered within the risk analysis of this IRP met expected planning reserve margin requirements in all seasons to help ensure sufficient resources are available to reliably serve demand and provide energy in all operating hours continuously throughout the year. Within the Reliability and Market Risk objectives in the scorecard, CEI South included metrics showing reliance on the capacity and energy markets, the amount of resources with fast start capability, and the amount of dispatchable resources with spinning reserve capability. Additionally, CEI South performed transmission planning analyses to consider voltage and reactive power support for various portfolios.

2.3.2.2 Affordability

For the Affordability objective, the metric used is the mean value for the 20-Year Net Present Value of Revenue Requirements ("NPVRR"), expressed in millions of dollars. The NPVRR is a measure of all generation related costs (for each asset, the cost of generation – capital, O&M, fuel and the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment. In this way, very different portfolios can be compared on a common metric or value over a long-time frame.

2.3.2.3 Cost Uncertainty Risk Mitigation

For the Cost Uncertainty Risk Mitigation objective, the metric used is the 95th percentile of NPVRR, also expressed in millions of dollars. After each portfolio was subjected to 200 dispatch model runs, a distribution is created of the NPVRR portfolio costs. The 95th percentile (approximately two standard deviations above the mean value) is a commonly used benchmark to demonstrate a reasonable upper threshold of cost risk under widely varying market circumstances. In addition, per stakeholder request, the portion of energy generation with exposure to coal and gas markets gives further insight to risks posed by commodity markets and potential future regulatory requirements. This metric, expressed as a percentage, is the generation from coal and gas divided by the total fleet generation across 200 iterations.

2.3.2.4 Environmental Sustainability

For the Environmental Sustainability objective, the metric estimated CO_2 intensity and per stakeholder request CO_2 equivalent stack emissions were calculated. In addition to carbon dioxide, methane and nitrous oxide emission factors for coal (bituminous) and natural gas were taken from Table C-1 to Subpart C to 40 Code of Federal Regulations part 98 December 9, 2016. Chemical-specific Global Warming Potentials ("GWPs") were taken from table A-1 to 40 Code of Federal Regulations part 98 Subpart A for a 200 year time horizon December 11, 2014.

Figure 2.3 – Emissions factors used to Convert CO_2 to CO_2e by Resource

Coal Emission Factors (kg/MMBtu)	
CH_4 Conversion factor	0.011
N_2O Conversion factor	0.0016

Natural Gas (NG) Emission Factors (kg/MMBtu)	
CH_4 Conversion factor	0.001
N_2O Conversion factor	0.0001

Global Warming Potential	
CH_4	25
N_2O	298

Tons to kg conversion	
kg	Metric Tons
1	0.001

Outside of the scorecard, CEI South considered direct portfolio emissions reductions for each portfolio compared to a base year (2005) of power generation and resulting CO_2 emissions. The 2005 benchmark year saw 9,634,957 short tons of CO_2 emissions.

2.3.2.5 Market Overreliance Risk Minimization

For the Market Overreliance Risk Minimization objective, there were two metrics. There is the average annual energy sales and the average annual energy purchases, each divided by average annual generation and expressed as a percentage. There is also the average annual capacity sales and the average annual capacity purchases, divided by average coincident peak demand and expressed as a percentage.

Other Considerations

2.3.2.6 Resource Diversity

CEI South believes resource diversity helps minimize risk to customers by providing a mix of resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed. CEI South's coal units have served its customers well over the years, but there continues to be pressure on this resource from evolving environmental regulations. F.B. Culley 3 continues to operate efficiently but will continue to be challenged to meet increasingly more stringent air regulations in the short and long term. A recent example is the passage of the Good Neighbor Rule, which ratchets down emissions standards across the country. While it does not change FB Culley 3's current operating thresholds beyond those required in the recently finalized CSAPR update, compliance with these ever evolving emission targets as described in 1.3.2.1.1 will likely be more difficult and costly in the future. The IURC reinforced this consideration that CEI South should consider resource diversity and alternatives that provide off ramps that allow CEI South to react to changing circumstances.

While very important, it is hard to create a measure that adequately captures this value. Instead, CEI South sought to develop portfolios that included a wide range of resource types and fuel sources. To ensure this objective has been met, CEI South built portfolios that ensure diverse mixes. CEI South included an All-Source RFP to fully consider renewable and battery storage resources within all portfolios.

2.3.2.7 System Flexibility

System flexibility was an important consideration in the 2022/2023 IRP. As intermittent renewable resources continue to grow on the transmission and distribution system, it is important to back these resources up for reliability and resilience. As such, CEI South considered performance of resources with the ability to start and ramp quickly and be available for sustained periods in times when the sun is not shining, and the wind is not blowing. CEI South also considers the transmission system and the ability to rely on the market as an important consideration in IRP planning. While CEI South has considerable import capabilities with the addition of the Duff Coleman Market Efficiency transmission Project ("MEP") and the recently energized East/West line, this capability is not unlimited and requires needed upgrades to maintain reliability for portfolios that rely less on traditional dispatchable energy resources. All portfolios include the recently approved natural gas CTs at A.B. Brown, which provide quick start, fast ramping capabilities.

2.3.2.8 Resilience

Resilience is the ability of a portfolio to recover from off normal events, like extreme/long duration weather events. With shrinking reserve margins in MISO and the recent, more frequent weather events, resilience has become an important consideration within the IRP. The state of Indiana recently included resilience as one of the five pillars in HB 1007. As such, all portfolios with new gas resources included costs for firm gas supply.

2.3.2.9 Stability

Stability is also one of the five pillars in HB 10007. It is the ability of the portfolio to help maintain system frequency and voltage, thermal limits, and power transfer capability. A portfolio must provide these essential functions. For more information, please see section 6.4.3 Transmission Facilities as a Resource for a description of CEI South's analysis and conclusions relating to this objective.

2.4 REFERENCE CASE ASSUMPTIONS AND BOUNDARY SCENARIOS

After selecting the objectives and metrics, the next step in the process was to define the scenarios for consideration in the selection of alternative portfolios. In this case CEI South selected a Reference Case and four alternative scenarios for two purposes. The first purpose was to create a least cost portfolio for each of the five scenarios and the second was to test final portfolios against each of the market scenarios to determine how well they perform. Below is a brief discussion of each. Greater detail is provided in Section 7 which identifies the key inputs for each scenario.

2.4.1 Reference Case

The Reference Case scenario represents the most likely future conditions. CEI South surveyed and incorporated a wide array of third-party sources to develop its Reference Case assumptions, several of which reflect a current consensus view of key drivers in power and fuel markets. Reference Case assumptions include forecasts of the following key drivers:

- Henry Hub and delivered natural gas prices
- Illinois Basin mine and delivered coal prices
- MISO Capacity Cost
- CO_2 ACE Proxy
- Capital costs for various generation technologies
- Load forecast

The long-term energy and demand forecast for the CEI South service territory was developed for CEI South by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, general service (commercial) and large (primarily industrial) usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, electric vehicle adoption and several demographic and economic factors.

For natural gas, coal, and capacity price, CEI South used a “consensus” Reference Case view of expected prices by averaging forecasts from several sources. This helps to ensure multiple views are considered and allows CEI South to be transparent with modeling assumptions. For natural gas and coal, 2022 fall forecasts from S&P, Wood Mackenzie, ABB, and EVA were averaged. The capacity price forecast was based on MISO Zone 6 forecasts from ABB and S&P. Note that seasonal capacity forecasts were not available at the time of this IRP. Those used were the best available information at the time. No CO_2 price was included in the Reference case. Rather costs were included for efficiency upgrades.

All-Source RFP bids were utilized for resource cost information between 2024 and 2042, where possible. Long-term cost curve information was developed by applying the National Renewable Energy Laboratory (“NREL”) Annual Technology Baseline (“ATB”) curve to more recent market based cost assumptions. The 1898 and Co. technology assessment helped fill in the gaps with operational data and for various technologies, including gas and coal resources.

CEI South worked with stakeholders and GDS to develop a Market Potential Study (“MPS”) for demand side resources. This study was used to create demand side inputs to be compared on a consistent and comparable basis with supply side resources.

1898 & Co. developed power price forecasts used for the Reference Case and the Alternative Scenarios using an EnCompass database and updating the commodity inputs and model assumptions associated with each of the unique scenarios. EnCompass was then used by 1898 & Co. to develop an optimized, least-cost portfolio for the Reference Case, which was then run in chronological hourly dispatch mode. These key drivers constitute the Reference Case assumptions. More information on modeling inputs can be found in Section 7.2 Reference Case Scenario.

2.4.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just the Reference Case. Hence, CEI South, with the support of 1898 & Co., selected four alternative scenarios (Market Drive Innovation, High Regulatory, Continued High Inflation and Supply Chain Issues and Decarbonization/Electrification) to provide boundary conditions for testing the technologies and developing portfolios that could be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

CEI South worked with 1898 & Co. and received input from CEI South stakeholders on key inputs such as load forecasts, gas and coal prices, carbon emission prices and technology capital costs. With input from stakeholders, CEI South and 1898 & Co. determined whether gas prices, coal prices, load, technology capital costs, carbon emission prices and power prices would move up or down relative to the Reference Case under each of those scenarios. This process was followed to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis. Below is an illustrative description of each scenario.

- High Regulatory – The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee is implemented throughout the planning horizon (2023 - 2042). A fracking ban is imposed, driving up the cost of natural gas notably in the long-term as supply dramatically shrinks. Declining demand for coal is offset by regulations that increase the coal price resulting in coal prices higher than the Reference Case as coal mines close and remaining coal producers can charge more per ton, passing costs of new regulations on to remaining customers. Although technological innovation is stifled, renewables and battery storage receive government incentives, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

- Market Driven Innovation – A transition to a more free market leads to new and advanced technology, driving down energy prices. Less government influence drives competition among competing fuels and no carbon tax results in lower power prices from natural gas and coal resources. Increased energy usage is a direct result of less government influence reducing overall costs. Further technological innovation to lower energy cost is spurred by an increase in demand for renewable and storage resource options. This advancement in technological innovation drives more opportunities for energy efficiency programs. Energy efficiency programs are predicted to be more cost effective with increased load. In addition, less codes and standards changes allow utility sponsored energy efficiency programs to transform the market at a lower incentive cost.
- Decarbonization/Electrification – Utility-sponsored energy efficiency costs are below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy. As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes and other buildings. The switch to electrification causes an increase in load and natural gas supply; however, the natural gas prices remain at Reference Case level due to methane regulations. A mid-level carbon tax is imposed causing demand for coal to decrease and supply constraints cause coal prices to increase. Technological improvements to lower costs are offset by higher demand and rising land and labor costs.
- Continued High Inflation & Supply Chain Issues – With a shortage in labor and materials, costs for new technologies and fuels increases. Higher labor and delivery costs reduced the supply of fuel leading to higher coal and natural gas prices. Load demand is negatively affected by high inflation causing reduced economic output. Like the Reference Case, no carbon price is imposed. Continued disruptions in the supply chain along with high inflation leads to higher costs for renewables and storage. Reduction in load results in less potential of energy

efficiency acquisition both for incentives passed to customers and implementation of programs as implementers experience increased cost. In addition, shortage of EE equipment leads to increased cost of high-efficient measures.

A summary of the relative outlooks for key market drivers across the scenarios considered is presented in Figure 2.4.

Figure 2.4 – Summary of Directional Relationships of Key Inputs Across Scenarios

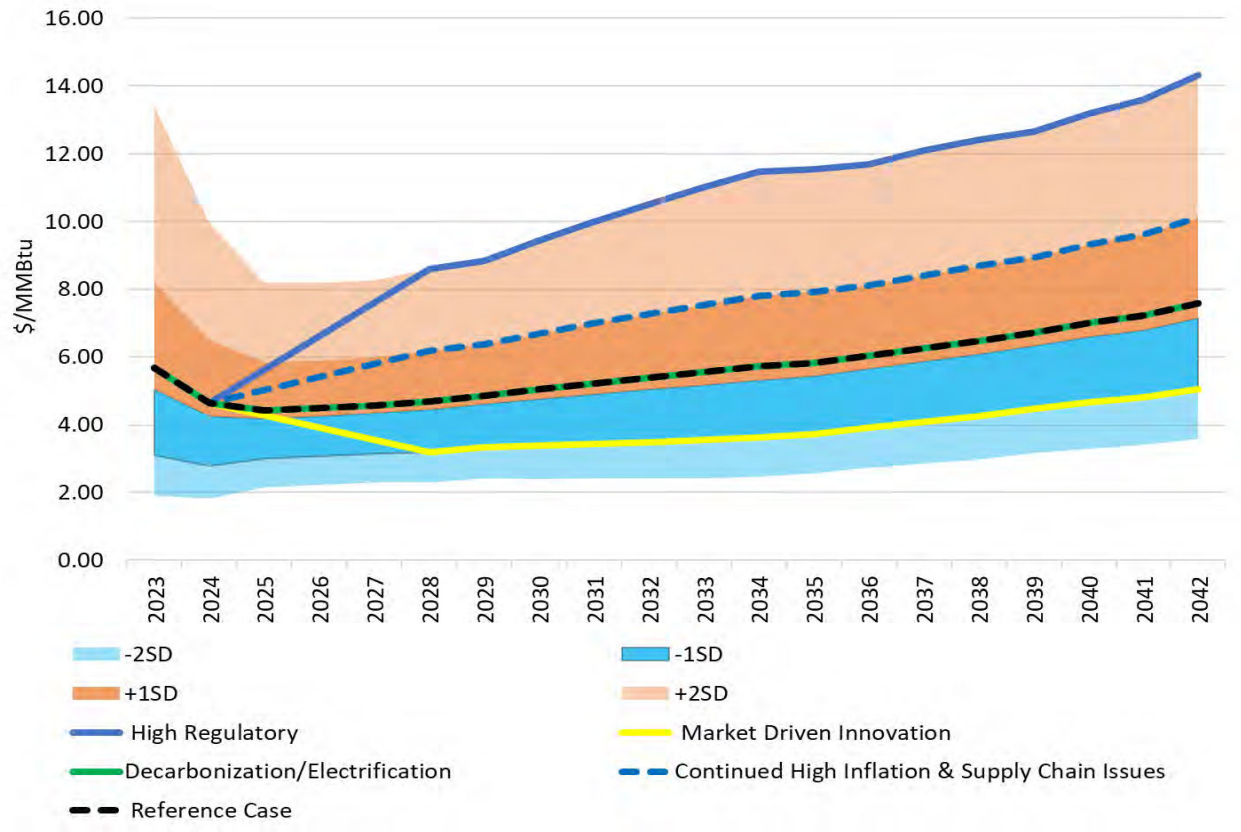
	CO_2	Gas Regulation	Other Environmental Regulations	Economy	Load	Natural Gas Price	Coal Price	Renewables and Storage Cost	EE Cost[19]
Reference Case	ACE Proxy	None	None	Base	Base	Base	Base	Base	Base
High Regulatory	Highest	Fracking Ban	MATS Update	Lower	Lower	Highest (+2 SD)	Higher	Lower	Higher
Market Driven Innovation	Base	None	None	Higher	Higher	Lower	Lower	Lower	Lower
Decarbonization/ Electrification	High	Methane	None	Base	Higher	Base	Higher	Base	Lower
Continued High Inflation & Supply Chain Issues	Base	None	None	Lower	Lower	Higher	Higher	Higher	Higher

Using the Reference Case as a consistent starting point, the boundary scenarios were developed. Key variables are assumed to remain the same as the Reference Case in the short-term (2022-2024). To the extent key variables differ from Reference Case value, they will vary by plus or minus one or two standard deviations ("SD"). The SDs were developed as part of the stochastic variable process described in Technical Appendix 11.6. In the medium-term (2024-2028), key variables grow or decline to +/-1SD or (+/-2SD) by 2028 (midpoint of medium-term) as shown in the table above. After 2028, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2042. Because this price path remains at the one (or two) SD(s) path for the entire planning horizon, these levels have

[19] EE costs were not varied by scenario within IRP modeling. Rather, CEI South worked closely with stakeholders to maximize the amount of energy efficiency to be selected. This process was done in lieu of varying price by scenario.

a low probability and are viewed as very wide. The five scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (five scenarios). An illustration of this methodology for natural gas prices is presented in Figure 2.5.

Figure 2.5 – Henry Hub Natural Gas Price Scenarios ($/MMBtu)



Under all scenarios Henry Hub gas prices begin at $5.68/MMBtu in 2023 and continue declining until hitting $4.65/MMBtu in 2024. After this time, the Reference Case gas prices gradually trend upward to $7.59/MMBtu in 2042. Gas prices in the other scenarios either follow the Reference Case or trend higher or lower, depending on the scenario's coordinated input direction. Gas prices in the High Regulatory scenario are designed to reach the +2 SD level to replicate the price impact of a hydraulic fracturing ban, which would greatly limit domestic production, increase costs and put upward pressure on

prices. The Market Driven Innovation scenario sees natural gas prices moving downward to -1 standard deviation below the Reference Case.

The convention of +/-1 or +/-2 SDs is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should be noted that the historical price distributions differ among the various market drivers are not necessarily symmetrical (i.e., normally distributed). For example, gas prices are positively skewed because they have no upper boundary and can reach many SDs above the historical average, whereas they typically cannot fall below zero (or approximately two SDs below the historical average).

The graphical descriptions of values for each of the key metrics (e.g., load, gas prices, coal prices, and technology costs) are shown in Section 7.3.2.2.

2.5 PORTFOLIO DEVELOPMENT

The portfolio development process was designed to test a wide range of technology options. An exhaustive list of technology options was developed and then refined. The viability of existing resources was considered as well as new resources including demand side measures of varying sizes and timeframes. The wide range of portfolio strategies was informed by stakeholder feedback as well as the All-Source RFP.

An All-Source RFP was issued at the onset of the IRP process to obtain actual market information for near term indicative pricing for a wide range of technologies. The average delivered cost by resource informed the modeling and portfolio options. This included new builds, power purchase agreements, demand response and other supply options. The results of the All-Source RFP were vetted by 1898 & Co. and ultimately converted into model inputs.

An 1898 & Co. technology assessment defined the list of technologies and provided cost and performance information for resources. Where possible, technology costs from the

All-Source RFP bids were utilized. Long-term cost projections started at prices received as part of the RFP and trended over time based on NREL projections. A total of 30 resource options for power supply were included in the analysis. These included wind with and without storage, solar with and without storage, hydroelectric, several battery storage options, simple cycle and combined cycle natural gas and natural gas fired combined heat and power technologies. Two new coal-fired technologies were included, both of which were assumed to be equipped with carbon capture and storage. Site specific studies were also conducted to provide cost and performance information for conversion options at A.B. Brown and F.B. Culley plants.

Long Term Capacity Expansion ("LTCE") Assessments

The EnCompass model was used as the central tool in the IRP to develop the 9 candidate portfolios in addition to the Reference Case portfolio. The long-term capacity expansion functionality within EnCompass was used to help develop portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants.

Market transactions offer supply flexibility but also exposure to potential market risk to CEI South customers. In addition to the supply and demand side resource alternatives, portfolios were able to select market supply options as well. To reduce the risk that comes from exposure to the market, a limit of 50 MWs of market capacity purchases was imposed beginning in 2029. Recent legislation was passed in Indiana, capping the reliance on MISO's planning resource auction at 15%. This limit helps to ensure portfolios do not overly rely on capacity purchases in the long term. There is more certainty in the near term about what might be available through bi-lateral contracts. As such, early years included higher thresholds of 300 MWs through 2025 and 180 MWs 2026-2028.

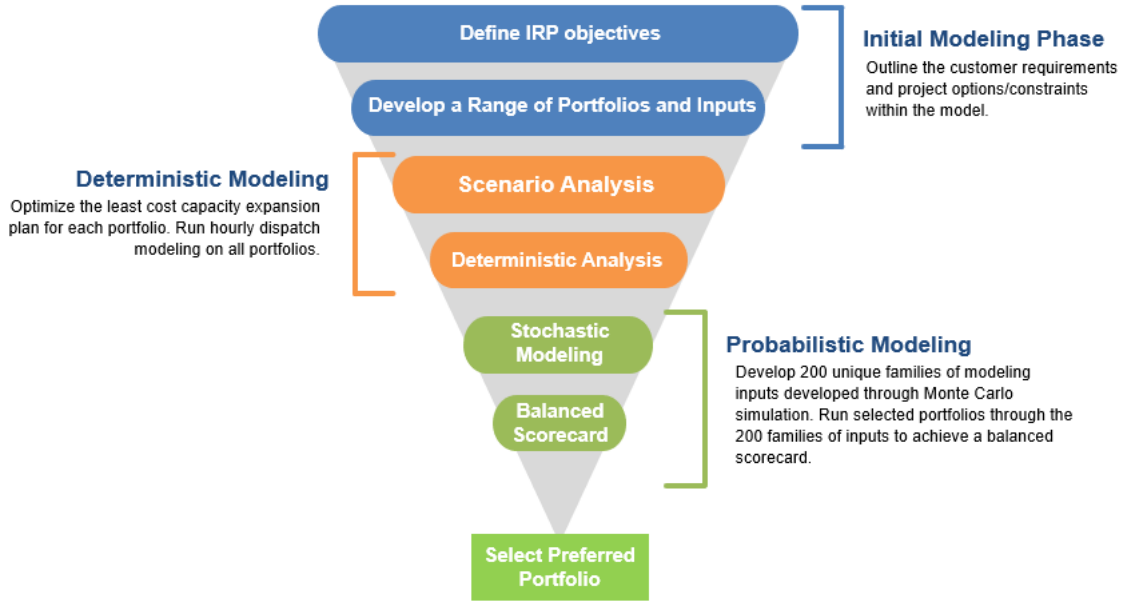
Portfolios were developed utilizing EnCompass modeling for the Reference Case, the alternate scenarios, and additional portfolios developed based on stakeholder feedback. The model uses hourly chronological dispatch over a 20-year period, which means

outcomes are based on all 8,760 hours each year over a 20-year span. This helped to better evaluate intermittent renewable and storage resources.

Figure 2.6

illustrates the portfolio screening process applied in the analysis to select the preferred portfolio. In addition to the scenario-based portfolios, CEI South and 1898 & Co developed many additional portfolios to ensure a wide range of technologies were assessed and influenced by stakeholder input to specifically evaluate alternate resource strategies. The refinement for each portfolio, whether it be a modification to an existing unit or requiring the addition of renewables was required as part of a portfolio and then the model selected the remainder of the portfolio on a least cost basis. Once the reference case, scenario-based portfolios, and additional deterministic portfolios were analyzed, CEI South was able to screen out costly, overlapping, or overbuilt portfolios.

Figure 2.6 – Structured Portfolio Selection Process



As described in Section 8, CEI South selected the reference case and the following nine portfolios for evaluation in the risk analysis. The selection criteria for eliminating the other portfolios are provided in that section.

1. Business as usual to 2042 including the continued operation of FB Culley 3 continues through study period;
2. Convert FB Culley 3 to natural gas in 2027;
3. Convert FB Culley 3 to natural gas in 2027 with wind and solar added in the same year;
4. Convert FB Culley 3 to natural gas in 2030;
5. Diversified Renewables;
6. Diversified Renewables with early storage and Distributed Generation solar;
7. Replace FB Culley 3 with a F-Class CT;
8. Replace FB Culley 3 with storage and solar; and
9. Replace FB Culley 3 with storage and wind.

2.6 PORTFOLIO PERFORMANCE (SCENARIO BASED RISK ASSESSMENT)

The framework of the Indiana law mandating a triennial IRP[20] also requires the creation of alternative future scenarios with unique sets of inputs. Each candidate portfolio must be modeled in a dispatch run using these scenario-based inputs, which can provide a complementary view of portfolio strengths and weaknesses, separate from the probabilistic analysis that serves as the basis for scorecard measures. Four alternative scenarios were created (High Regulatory, Market Driven Innovation, Decarbonization/Electrification, and Continued High Inflation & Supply Chain Issues), each with a unique set of inputs. All 10 candidate portfolios were modeled in a separate dispatch run for each of the four alternative scenarios.

[20] Indiana Code § 8-1-8.5

EnCompass was run in a market simulation mode holding each of the CEI South portfolios constant but allowing the input assumptions to vary in each of the 200 draws. The results of the scenario-based risk analysis are summarized in Section 8.2.1.

2.7 PORTFOLIO PERFORMANCE (PROBABILISTIC AND STOCHASTIC MODELING RISK ASSESSMENT)

Probabilistic modeling incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for the balanced scorecard and key drivers portion of the risk analysis. Probabilistic modeling begins with the development of 200 sets of future pathways for monthly coal prices, natural gas prices, carbon prices, peak load, and capital expenditures for renewable resources. The 200 sets of inputs were created by developing probability distributions around each uncertainty variable, then stochastically sampling the inputs together to arrive at 200 sets of inputs. These 200 sets of stochastic inputs are then run through the dispatch model, one set at a time for the selected portfolios. 200 instances of key metrics from the dispatch modeling are then used to form distributions around the key output metrics. Thus, the stochastically developed inputs allow for the testing of each portfolio's performance across a wide range probable market conditions.

Once again, all 10 portfolios were subjected to each of the 200 iterations (scenarios) using EnCompass in dispatch mode where the CEI South portfolio is fixed.

2.8 SENSITIVITY ANALYSIS

CEI South conducted several sensitivities in order to put brackets around resulting portfolios when one or more variables were adjusted.

- CEI South performed a sensitivity to test the impact on portfolio NPVs under a sensitivity where CEI South would not be able to monetize 100% of the ITC for new storage projects. In the sensitivity, it was assumed that only 85% of the ITC was received by CEI South. This decrease in ITC monetization results in slightly

higher portfolio NPVs. For every 100MW of storage included in a portfolio the NPV would increase by approximately .1% with this reduced ITC monetization percentage.

- The reference case portfolio was run by CEI South with no constraints on the model which resulted in a conversion of two combustion turbines to a combined cycle in 2027 along with 400 MW of wind in 2033 and 10 MW of storage in 2030 and 2042 to meet load requirements during the study period. F.B. Culley 3 remained on-line through 2029.
- CEI South performed a sensitivity to test the impact of increases in wind cost on portfolio NPV and resource decisions. Based on this analysis, if wind costs were to increase, alternate resources, such as solar or storage resources would be selected in order to meet planning reserves with little to no NPV impact on the portfolio.
- CEI South evaluated the cost risk of potential changes in New Source Performance Standard 111B. All 10 portfolios were run through 200 different simulations during the risk analysis, of which 80 included a carbon tax. This potential change in legislation helps to quantify the potential magnitude of the impact different portfolios would be exposed to under future changes to emissions regulation. From the analysis, each of the 10 portfolios saw a 16% - 26% increase in NPV with the inclusion of additional emissions regulation. Portfolios that included converting F.B. Culley 3 to natural gas or had additional renewables and storage experienced less cost risk associated with future emissions regulation changes than the portfolio that included the continued operation of F.B. Culley 3 on coal.
- A sensitivity was run on the impact of a lower capacity accreditation for battery storage over the study period. The base battery storage accreditation included in the modeling was 95% throughout the study period. It is expected that with MISO's shift to a seasonal construct and reviewing of renewable and storage accreditation methodology, there is potential that battery accreditation will decrease in the future. For modeling of this sensitivity, a declining capacity accreditation was applied. The updated capacity accreditation starts at 100% in 2023 and decreases from 2028

until 2037 to 75% where it remains for the rest of the study period. These annual battery storage capacity accreditation values were utilized by MISO in their MISO Futures Report LRTP Tranche 2 Refresh[21]. When the capacity accreditation is updated from 95% to the declining curve, portfolios which include storage are more reliant on market capacity purchases or would need to procure additional resources to meet CEI South's capacity needs. The reduction of capacity accreditation in the out years from 95% to 75% results in increased portfolio costs of up to 2.9%. Future seasonal capacity accreditations for 4-hour storage are difficult to quantify in MISO, but as more storage is added to the system accreditation is expected to decline. In some regions of the US, storage capacity accreditation is projected to decline even further than the 75% accreditation used in this sensitivity.

- CEI South evaluated the impacts of a large industrial load on their system. A 300 MW increase to the current load forecast was included in the modeling. From an unconstrained run this led the model to select the conversion of AB Brown 5 and 6 CTs to a CCGT and additionally selected a J-class CT in order to meet the energy and capacity needs of new and existing customers.

2.9 BALANCED SCORECARD

The Risk Analysis (based on the probabilistic modeling) of each of the portfolios was developed by 1898 & Co. using the EnCompass dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs.

[21]MISO LRTP Tranche 2 – Future Refresh Assumptions Book; April 27, 2023
https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf

- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario input development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the EnCompass production cost model. EnCompass dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, EnCompass assumes that each CEI South candidate portfolio is constant[22] but the input assumptions vary in each of the 200 draws. CEI South generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations.
- The averages of these measures are used as the basis for evaluation in the balanced scorecard.

The results of risk analysis can be found in Section 8 Portfolio Development and Evaluation.

2.10 SELECTION OF THE PREFERRED PORTFOLIO

The risk analysis includes scenario modeling, probabilistic modeling, sensitivity and other analyses to inform judgment in the selection of the preferred portfolio. In addition, a key part of selecting the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, under 200 iterations representing different, but internally consistent and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each candidate portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations, while also maintaining reliability and providing resource diversity, system

[22] Capacity purchases are allowed to change between the 200 draws to meet planning reserve margin requirements

flexibility, resilience and stability. To help illustrate tradeoffs, CEI South used a Balanced Scorecard, as shown below in Figure 2.7 and further discussed in Section 8.

Figure 2.7 – Balanced Scorecard Illustration

Balanced Scorecard	Objective	Affordability / Cost Risk				Environmental Sustainability		Reliability				Market Risk Minimization							
Portfolio	Metric	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2/kwh)	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2)	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)		Fast Start Capability (MW)	Spinning Reserve (MW)	Energy Market Purchases			Energy Market Sales			Capacity Market Purchases or Sales (%)	
								Summer	Winter			Average	Near Term Max	Long Term Max	Average	Near Term Max	Long Term Max	Purchases	Sales
Reference Case																			
Business as Usual																			
Convert F.B. Culley 3 to Natural Gas by 2027																			
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar																			
Convert F.B. Culley 3 to Natural Gas by 2030																			
Diversified Renewables																			
Diversified Renewables (Early Storage & DG Solar)																			
F-Class CT																			
Replace FB Culley 3 with Storage and Solar																			
Replace FB Culley 3 with Storage and Wind																			

The preferred portfolio represents CEI South's assessment, based on the analysis, of an appropriate balance between all identified objectives (See Figure 2.2) under a wide range of future conditions.

SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION PROCESS

CEI South continues to incorporate continuous improvement opportunities into the stakeholder process based on comments in the Director's report and stakeholder feedback. Most importantly, CEI South implemented tech-to-tech calls and file sharing throughout the process to allow for more meaningful information sharing and dialogue. As a result, significant stakeholder input was directly included in key areas of the IRP, including but not limited to portfolio development, scenario development, scorecard development (metrics and measures), and modeling inputs such as energy efficiency inputs. While improvements have been made, CEI South's objectives for stakeholder engagement remain the same:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions and the challenges facing CEI South and the electric utility industry
- **Consider**: Provide multiple forums for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform CEI South's decision making

IRP stakeholders include, 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.

In the first public stakeholder meeting, CEI South publicly made 12 commitments and followed through with all throughout the process (significant improvements per stakeholder request noted in italics):

1. To strive to make every encounter meaningful for stakeholders and for us
2. That the IRP process informs the selection of the preferred portfolio

3. To utilize an All-Source RFP to gather market pricing & availability data (*incorporated stakeholder feedback prior to publishing)*
4. *Per stakeholder request*, to utilize EnCompass software to improve visibility of model inputs and outputs
5. *Per stakeholder request*, to conduct technical meetings (tech-to-tech) with interested stakeholders who sign an NDA
6. To include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
7. To work with stakeholders on portfolio development
8. To test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
9. To conduct a sensitivity analysis
10. To evaluate options for existing resources
11. That the IRP will include information presented for multiple audiences (technical and non-technical)
12. *Per stakeholder request*, to provide modeling data to stakeholders as soon as possible
    - Draft Reference Case results – October 4th to October 31st
    - Draft Scenario results – December 6th to December 20th[23]
    - Full set of final modeling results – March 7th to March 31st [24]

The first three stakeholder meetings began with stakeholder feedback. CEI South would review all requests since the last stakeholder meeting and provide feedback. Often suggestions were incorporated, but in instances where suggestions were not, CEI South made a point to discuss further and explain why not. Notes for each meeting were included in question and answer format, summarizing the conversations. Additionally,

[23] Provided final draft modeling files on December 20, 2022, for stakeholders that signed an NDA as part of the tech-to-tech group
[24] Updated deterministic modeling results were provided to stakeholders on March 7, 2023, and provided stochastic modeling results April 27, 2023, following the final public stakeholder meeting.

feedback was received, and questions were answered via e-mail (irp@centerpointenergy.com) and tech-to-tech meetings in between each session per stakeholder request. The final meeting was a preview of the preferred portfolio and a discussion of the analysis. CEI South felt it was important to hold all stakeholder meetings in person in Evansville, IN (including an option to attend virtually). Tech-to-tech meetings were held virtually.

Stakeholder Meeting dates and topics covered are listed below:

Figure 3.1 – 2022/2023 Stakeholder Meetings

August 18, 2022	October 11, 2022	December 13, 2022	April 26, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

Meeting materials of each meeting can be found on www.centerpointenergy.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

Per stakeholder request, CEI South included tech-to-tech meetings with stakeholders who signed an NDA. The purpose of the meetings was to discuss confidential information between public stakeholder meetings. The invitation was open to those that did not have a competitive interest in the information being shared. The OUCC, CAC, Sierra Club, and IURC staff regularly attended these meetings. Most often, the topic of conversation was draft modeling inputs/outputs. Stakeholder tech-to-tech Meeting dates and topics covered are listed below:

Figure 3.2 – 2022/2023 Tech-to-Tech Meetings

October 31, 2022	November 7, 2022	December 7, 2022	Feburary 28, 2023
• Modeling timeline • Modeling updates • Modeling setup • Accreditation of resources • Preliminary Reference Case model selections	• Reviewed 25 CAC questions on EnCompass modeling input file	• Review of modeling ouputs (confidential slides) ahead of CEI South stakeholder meeting	• Discussed risk analysis portfolios • Discussed updated reference case modeling results for each portfolio • Discussed scenario modeling results for each portfolio • Reviewed draft scorecard • Stochastic modeling approach

Beyond 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.

3.2 KEY ISSUES DISCUSSED AND STAKEHOLDER INPUT

Throughout the process CEI South engaged stakeholders on key inputs into the IRP, which helped shape the outcome of the analysis. This section of the IRP highlights some of the key issues discussed and stakeholder input. For a more complete summary of stakeholder feedback addressed in each stakeholder meeting, please see section 3.1 in the technical appendix.

3.2.1 All-Source RFP

The 2022/2023 IRP kicked off with an All-Source Request for Proposal that was issued on May 11, 2022, where CEI South solicited input and incorporated feedback from stakeholders prior to posting. Stakeholders requested several updates to the All-Source RFP prior to it being issued. CEI South made updates accordingly in the following areas:

- CEI South added specific language to allow for proposals to consider re-use of injection rights;
- CEI South invited proposals of all size and removed the prohibition of behind-the-meter generation;
- CEI South added language to clarify how bidders should submit bid pricing;
- CEI South allowed storage proposals of any size and duration;
- CEI South included suggestions on scoring criteria regarding historical performance; and
- CEI South also clarified some language and made some corrections to the document.

After receiving initial bids, the Inflation Reduction Act (IRA) was passed. Stakeholders requested bidders be allowed to update their proposals to reflect the passage of the IRA. Bidders were provided an opportunity to update their proposals to reflect the most current information available. New information was incorporated into the modeling, and updated bid information was provided to stakeholders, without a competitive interest, who signed an NDA.

3.2.2 Resources

Throughout the process stakeholders made specific requests around resources that were modeled. Below are some major adjustments within IRP modeling. For a larger list of updates, please see the technical assessment, section 3.1.

3.2.2.1 Battery Storage

Battery Storage resources were discussed throughout the process. CEI South initially planned to model a long duration storage resource utilizing compressed air storage as a proxy for a breakthrough technology. This resource, while not likely available to CEI South, is an established technology providing similar benefits to the system. Real costs were utilized to provide this estimate.

IRP stakeholders did not agree compressed air storage was a good proxy for long duration storage and suggested CEI South either include longer duration lithium ion or utilize an upcoming technology like, iron air battery. While iron air batteries could help solve the long duration storage need, the technology is not yet in commercial operation, and CEI South did not have good cost data to model in this IRP. CEI South will continue to watch updates from Form Energy, the industry leader of this upcoming technology, and may incorporate this resource in future IRPs. Ultimately, CEI South did allow the model to select multiple four-hour blocks of lithium ion storage or an alternative 10-hour storage resource. The long-duration storage proxy was pushed out to 2032, so it could not be selected in the near term. While available for selection, it was not selected as a resource within optimizations.

Stakeholders also had suggestions about how batteries should be modeled, and the following updates were made:

- Utilized bid information to update low- and high-cost paths. CEI South acted on this suggestion and started price paths at lower and higher points, based on the highest and lowest bids included within the pricing average. This allowed for price variation in the early years of deterministic modeling.

- Updated model to reflect impact of the ITC to be reflected in year one. Ultimately this adjustment was more in line with the intent of the IRA and lowered the upfront cost for this resource.

3.2.2.2 DSM

Demand Side Management (DSM) resources were consistently discussed throughout the IRP process with stakeholders in public meetings, DSM oversight meetings (OUCC and CAC), and in one-off meetings with external stakeholder consultants to better understand inputs and results. CEI South discussed both demand response and energy efficiency.

Beginning with demand response, stakeholders requested CEI South model more industrial demand response. CEI South has no more industrial demand response registered with MISO; as MISO rules have evolved, there are no customers still interested in the program. However, recognizing CEI South will be in for a rate case at the end of 2023 with an opportunity to adjust rates and a stakeholder suggestion that CEI South work with an aggregator to try to untap potential opportunity in this area; CEI South agreed to increase the amount of demand response modeled to 25 MWs in all seasons. The cost of this program was set consistent with a bid received in the All-Source RFP, and CEI South has engaged this aggregator to see if they can help us procure more C&I DR. Conversations are on-going.

Another request of stakeholders was to pursue a residential rate program. As discussed in section 6.3.2.6 Other Innovative Rate Design, CEI South is actively planning to pursue a critical peak pricing pilot. This pilot should help CEI South better evaluate the potential of this Time of Use program and will provide valuable data for future IRPs. CEI South did model an indicative pilot in this IRP.

Multiple other adjustments were made to model energy efficiency programs. CEI South is committed to helping its customers use energy wisely and save money on energy bills; as such, CEI South worked hard to maximize the amount of energy efficiency that could

be selected within the model through regrouping various programs to ensure the right level of cost-effective energy efficiency was economically selected. CEI South worked collaboratively with stakeholders to help them understand inputs and worked to make adjustments consistent with stakeholder suggestions. Specific adjustments, consistent with stakeholder input, are included below:

- Captured avoided T&D line losses at marginal level instead of system average;
- Included 25 MWs of Industrial DR as a resource;
- Modeled "enhanced RAP" for commercial EE. This includes all realistic, achievable, potential and some maximum achievable potential;
- Adjusted low-income bundles to include higher short-term inflation rates;
- Plan to evaluate rate programs (critical peak pricing, TOU, etc.) in the future through a pilot; and
- Separated residential bundles into high cost and low to medium cost.

Ultimately this process was used to adjust EE cost to the maximum level, utilizing MPS data. CEI South felt this approach was superior to adjusting costs in scenarios and deviated from the initial approach of adjusting price based on a standard deviation up or down.

3.2.2.3 Hydro Electric

Stakeholders requested CEI South fully consider hydroelectric resources, given our proximity to the river and the benefits this resource provides. CEI South included two hydroelectric sources within optimization modeling, which included the ITC benefit provided in the IRA legislation, recently passed by the Biden administration. One project is located near F.B. Culley Power Plant, and the other is located near A.B. Brown Power plant. Even with the ITC applied, these resources were not selected based on economics. Additionally, CEI South modeled several portfolios that included hydro; however, these portfolios were ultimately screened out due to high cost. While these resources could help further diversify CEI South's fleet, the relatively small size and high cost led to hydro not being included in any portfolios that ultimately were included within the risk analysis.

3.2.3 Commodity Prices

CEI South began the IRP process by gathering commodity price forecasts from multiple sources. The timing of the IRP stakeholder process corresponded to a spike in natural gas prices. As such, stakeholders disagreed with the original consensus forecast, stating the original consensus forecast was too low. CEI South agreed to update the forecast and utilized the most up to date forecasts from each of its vendors, prior to finalizing modeling. Gas prices have been very volatile over the last year, peaking at around $9 per Million Btu (Henry Hub spot prices) in August 2022, the time of our first IRP stakeholder meeting to around $2 in February 2023. The CEI South reference price forecast reflects forecasts are higher than what was originally developed. Updated forecasts reflect the price spike in the summer of 2022.

Another adjustment CEI South made to commodity price forecasts is reflected within scenarios modeling. Originally, in the high regulatory scenario, CEI South reflected a coal price that was the same as the reference case, noting demand would be going down, offsetting a potential increase that may come through higher regulations. Stakeholders pushed back on this narrative. Based on comments provided, CEI South found it plausible that in a high regulatory scenario coal prices could increase as coal mines shut down due to a more oppressive regulatory environment. This could lead to the remaining coal producers charging more, passing costs of new regulations on to remaining customers. CEI south updated the high regulatory scenario coal price to be higher than the reference case.

3.2.4 Score Card

Several significant additions were made to the scorecard per stakeholder request across multiple objectives. First, CEI South added the portion of energy generation with exposure to coal and gas markets gives further insight to risks posed by commodity markets and potential future regulatory requirements. This metric, expressed as a percentage, is the generation from coal and gas divided by the total fleet generation across 200 iterations.

Second, CEI South calculated CO_2 equivalent stack emissions within the Environmental Sustainability objective to account for other emissions that are created by burning coal or natural gas. Third, CEI South added metrics in the Market Risk Minimization objective to provide more information to better understand reliance on energy sales / purchases and annual capacity sales / purchases in the near term and the long term.

3.3 STAKEHOLDER INPUT

During the 2022/2023 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) via written feedback/requests; 3) ongoing conversations; and 4) tech-to-tech meetings between stakeholder sessions.

CEI South worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each CEI South stakeholder meeting was opened by Richard Leger, Senior Vice President Indiana Electric. He and other senior management, CEI South subject matter experts and expert consultants actively participated in each meeting to help address stakeholder questions/concerns.

Below is a summary of key feedback that was ultimately included in the 2022/2023 IRP analysis. For a full list, including suggestions not taken, see the technical appendix Technical Appendix Attachment 3.1 Stakeholder Materials.

Figure 3.3 – Summary of Key Stakeholder Input

Request	Response
Allow All-Source RFP respondents to update their proposals to account for the IRA	RFP respondents were given the opportunity to update their bids (updated results were incorporated into the IRP)

Request	Response
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	Cumulative CO_2 equivalent (stack emissions) were added to the scorecard along with CO_2 intensity
Add a fuel cost risk measure and objective to the scorecard	Cost Risk metric was included in the scorecard, including both fuel risk and 95% percentile cost risk
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South included 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR customers as a registered resource in MISO. CEI South is engaged in conversations with a demand response aggregator to capture the potential of C&I demand response to further diversify our resource mix
CenterPoint should include demand response using the same methodology as AES. Implement residential rate programs (critical peak pricing, TOU, etc.) soon	CenterPoint has adopted the AES methodology and DR is aligned with peers to incorporate indicative TOU pilots. CEI South is planning to evaluate a TOU rate in the future through a pilot.
In the summer of 2022, the reference case forecasts for coal and natural gas prices showed a decline in the near term and do not reflect current pricing	Gas and coal price forecasts were updated as new forecasts became available in late fall of 2022

Request	Response
Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	CEI South found it plausible that coal prices could be higher in a high regulatory scenario and updated the price path to be higher than reference case in the high regulatory scenario
Revise the wind profiles being used in the model to differentiate between the output of northern Indiana and southern Indiana wind	The output profiles for wind resources were updated (increased) to better align with the information received from wind resources in the All-Source RFP
Explore alternative retirement dates for Culley 3	Culley 3 will be evaluated in scenarios with a potential retirement date of 2029 (pulled forward from 2030). Also included an alternative that converts F.B. Culley 3 to natural gas by 2027
Update modeling to reflect ITC storage year one	CEI South modeled the ITC benefit for storage in year one
Include full monetization of ITC for hydro resources	Included
Request for continued on-going dialogue following the December public stakeholder meeting	Held a tech-to-tech meeting on February 28, 2023 to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment

Request	Response
Include site -specific assumptions for the energy community bonus for PTC and ITC associated with the IRA	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions
Evaluate a portfolio with hydroelectric	Hydroelectric was not selected as a least cost resource within modeling. Several portfolios with hydro were evaluated, but they were higher cost and not included in the risk analysis
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

3.4 DATA REQUESTS SUMMARY

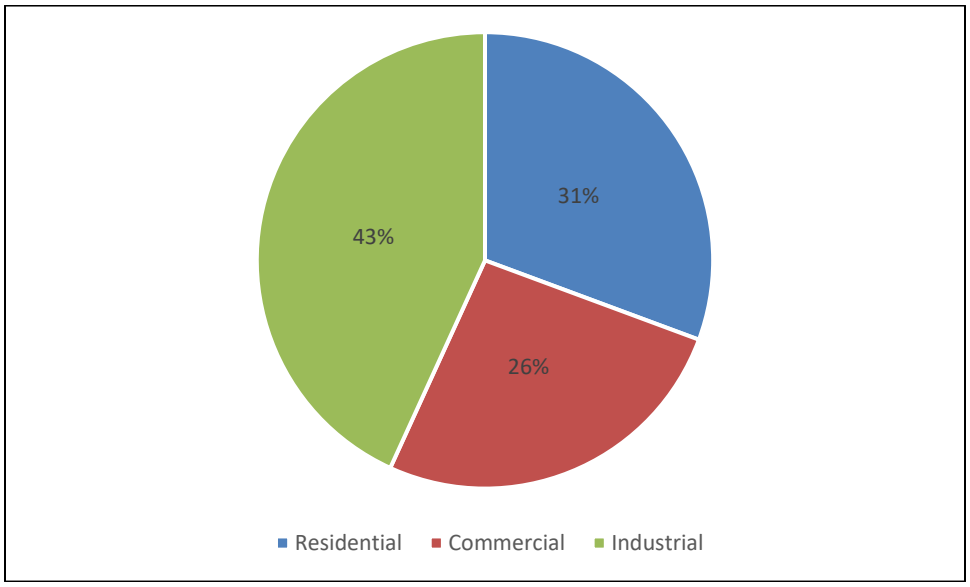
During the public stakeholder process CEI South received seven informal data requests from the CAC and Sierra Club. These data requests and CEI South's response can be found in the technical appendix 3.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

CEI South serves more than 151,000 electric customers in Southwest Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 43% of energy sales in 2022. The residential class accounts for 31% of sales with approximately 132,000 customers and the commercial class 26% of sales; there are approximately 19,000 nonresidential customers. System 2022 energy requirements were 4,571 GWh with non-weather normalized system peak reaching 1,022.2 MW. Figure 4.1 shows 2022 class-level sales distribution.

Figure 4.1 – 2022 CEI South Sales Breakdown



4.2 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. Similarly, small 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.

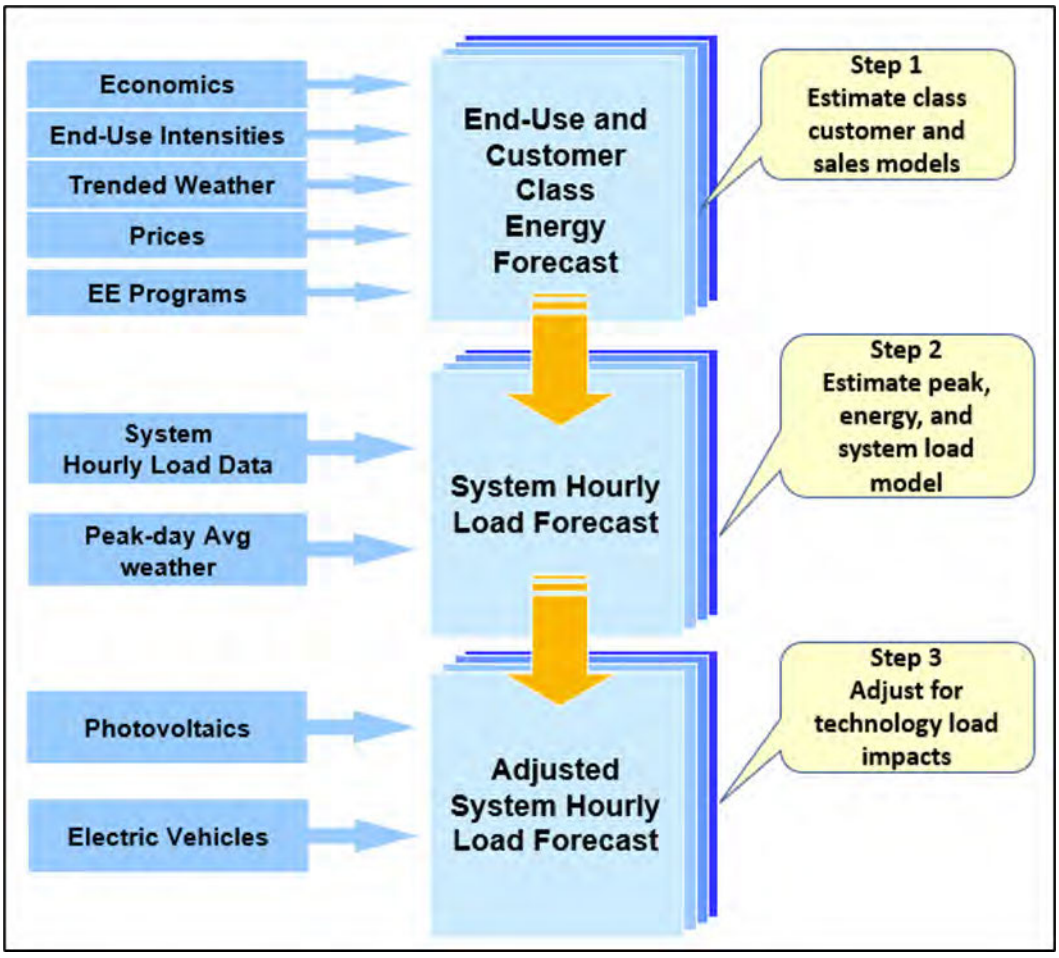
Weather is also a driver of electric consumption. CEI South's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Itron used a trended weather assumption for the normal weather in the sales and demand forecast in order to capture recent weather activity. The trended weather picks up the 0.05 degree annual increase in temperature the Evansville area has experienced since 1988.

Itron, Inc. 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 latest appliance saturation survey data.

4.3 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 4.2 shows the general framework and model inputs.

Figure 4.2 – 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.

4.4 CUSTOMER OWNED DISTRIBUTED ENERGY RESOURCES

Distributed generation ("DG") is an electrical source interconnected to CEI South's transmission or distribution system at the customer's site. The power capacity is typically small when compared to the energy companies' centralized power plants. DG systems allow customers to produce some or all of the electricity they need. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load. With respect to CEI South's electric service territory, DG will likely take these forms:

Small – 10 kW and under – roof-top photovoltaic ("PV") systems, small wind turbine, etc. interconnected at distribution secondary voltage (120/240 V, etc.)

Medium – 10 kW to 10 MW – large scale PV systems, wind turbine(s), micro-turbine(s), etc. interconnected at distribution primary voltage (4 kV or 12 kV)

Large – 10 MW and over – heat recovery steam generator, combustion turbine, etc. interconnected at transmission voltage (69 kV and above)

Most renewable DG systems only produce power when their energy source, such as wind or sunlight, is available. Due to the intermittency of the power supply from DG systems, there will be times when the customer needs to receive electricity from CEI South. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to CEI South's electric system through one of two programs, Net Metering or Excess Distributed Generation ("EDG"). Net metering customers are charged the retail rate for the net power that they consume. EDG customers are credited at the EDG rate for their excess power and charged the retail rate for the inflow power delivered by CEI South.

4.4.1 Current DG

As of December 2022, CEI South had approximately 982 residential solar customers and 139 commercial solar customers, with an approximate installed capacity of 27.8 MW. Based on recent solar installation data, the residential average size is 10.5 KW, while the commercial average system size is 126.2 KW. CEI South has incorporated a forecast of customer-owned photovoltaic systems into the sales and demand forecast.

CEI South monitors Combined Heat and Power ("CHP") developments in its service area and adjusts the load forecast for any known, future customer-owned CHP installations. A large CHP system went into service on CEI South's system in 2017.

4.4.2 Solar DG Forecast

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline in the long run.

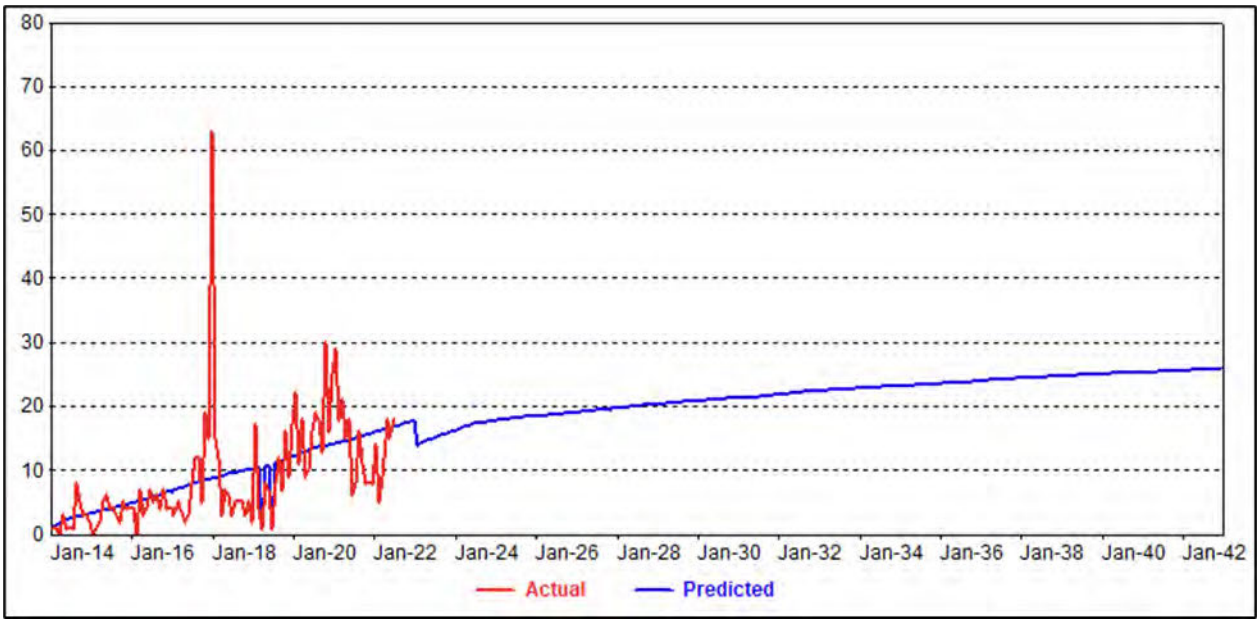
The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity generated from the system is considered "free". Solar investment payback is calculated as a function of system costs, tax credits, and incentive payments, retail electric rates and treatment of excess generation (solar generation returned to the grid). The payback calculation incorporates the impact of switching from net metering to the EDG. Federal investment tax credits are extended in accordance with the Inflation Reduction Act.

One of the most significant factors driving adoption is declining system costs: costs have continued declining over the last five years[25]. In 2010, residential solar system cost was approximately $8.00 per watt. By 2020 costs had dropped to $3.80 per watt. For the forecast period, system costs are expected to continue to decline 10% annually through 2024 and an additional 3% annually after 2024.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 4.3 shows the resulting residential solar adoption forecast.

[25] Lawrence Berkeley National Laboratory, Tracking the Sun report, pages 26 and 33 https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2022_report.pdf

Figure 4.3 – Residential Solar Share Forecast



In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Some challenges to commercial adoption are higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill) and physical constraints as to the placement of the system. For this forecast, Itron assumed there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates.

As shown in Figure 4.4, incremental installed capacity of solar is expected to increase by 130.9 MWs by 2042.

Figure 4.4 – New Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity MW (Aug)	Demand Impact MW
2022	1,537	1.8	0.7
2023	8,211	6.5	2.3
2024	15,018	11.4	4.1
2025	22,399	16.8	6.0
2026	30,039	22.3	8.0
2027	37,960	27.9	10.0
2028	46,299	33.9	12.1
2029	54,615	40.0	14.4
2030	63,335	46.2	16.6
2031	72,103	52.5	18.9
2032	81,374	59.1	21.3
2033	90,470	65.7	23.4
2034	100,029	72.6	17.9
2035	109,595	79.4	19.6
2036	119,645	86.5	21.2
2037	129,363	93.6	23.1
2038	139,416	100.9	24.7
2039	149,790	108.3	26.3
2040	160,542	115.8	28.6
2041	170,589	123.2	30.2
2042	181,272	130.9	32.2

4.4.3 Potential Effects of Distributed Generation on T&D

Distributed Generation customers currently affect a small amount of load on each respective distribution circuit, which has not caused significant operational issues for CEI South. At higher levels of DG penetration, CEI South would encounter more operational issues and would need to allocate more resources to mitigate these issues. Some examples of potential issues would include:

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output.
- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer.

Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company.

- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc.
- **Short-term load forecast uncertainty** – At higher levels of DG penetration, short-term load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. A load forecasting technique would need to be implemented that is more granular and more responsive to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and maintain acceptable voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, capacitor bank placement will need to be reevaluated.
- **Electric Rates** – CEI South's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed monthly charge does not reflect the full amount of fixed costs that CEI South incurs to provide retail electric service. Net Metering customers (who generate a portion of their own electricity but still rely on the electric grid) may avoid paying towards the recovery of the fixed costs of the grid that are recovered through the energy charge, which leads to CEI South's under recovery of the cost of providing service. Over time, as base rates are updated periodically, recovery of these costs shifts to non-net metering customers, resulting in a subsidy to net metering customers. Net metering is only available to

premises that installed an eligible generation system prior to implementation of Rider EDG.

- **Transmission Power Flows –** High DG penetration impact power flow on transmission lines. Depending on the concentration and location of these resources, the transmission system may need to be reconfigured, with consideration given to the dependency of the resources on the weather (wind, solar, etc.). High DG penetration may also impact flows on transmission system tie lines to other entities and require additional mitigations, such as installation of reactors or phase shifters to control flows.
- **Generation Reserves** – With the output of DG being weather dependent, the remaining fleet of generators and the electric system must be capable of quickly reacting to the fast and potentially large generation changes on the system, as well as providing generation support during times when DG will not be available (such as nighttime for solar DG). The adoption of Electric Vehicles could also lead to increased load demand in the nighttime hours as they are charging. These issues will need to be evaluated and potentially require mitigations such as storage facilities, quick start generators, etc.
- **Additional Operational Challenges** – High DG penetration causes additional challenges to operate the electric system in a safe and reliable manner due to loss of inertia on the power system by replacing traditional rotating machine generators (high inertia) with inverter-based generators (no/low inertia). These challenges include maintaining spinning and quick start reserves, power system frequency fluctuations and increased system operations (tripping), among others. Each of these issues would need to be evaluated and potentially mitigated to maintain reliable and safe power system operation.

4.5 ELECTRIC VEHICLES

4.5.1 Current EVs

In 2019, CEI South estimated 238 registered electric vehicles were in the counties that CEI South serves: this included full electric (i.e., Battery Electric Vehicles - BEV) as well as plug-in hybrid electric ("PHEV") vehicles. The 238 vehicles were comprised of 105 BEVs and 133 PHEVs, with a total of 23 different make/model vehicles represented. This estimate was based on Indiana BMV registration data for the counties that CEI South serves. CEI South purchases quarterly from the BMV a list of vehicle registrations for the counties that CEI South serves.

4.5.2 EV Forecast

As electric vehicles are gaining more traction in the vehicle market, CEI South decided to include an electric vehicle forecast in the 2022/2023 IRP. As described in the 2022 Long-Term Electric Energy and Demand Forecast Report in the Technical Appendix 4.1 of this IRP, Itron created an electric vehicle forecast utilizing a consensus forecast, averaging the EIA Annual Energy Outlook and BloombergNEF forecasts to calculate the share of registered light-duty vehicles which are electric. Itron used the EIA's assumption of total light-duty vehicles per household. Using this data, the average number of cars per household and projected electric vehicle shares were calculated. This number is multiplied by the forecast of residential customers to create a projected number of vehicles per CEI South household. Itron then applied the consensus projected saturation of battery electric vehicles and plug in hybrid electric vehicles.

Electric vehicles' impact on CEI South's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. Battery electric vehicles ("BEV") consume more electricity than plug-in hybrid electric vehicles ("PHEV") and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual

kWh for the current mix of EVs registered in CEI South's service territory is 3,752kWh for BEV and 2,180 kWh for PHEV based on annual mileage of 12,000 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since CEI South does not have incentivized BEV/PHEV off-peak charging rates, it is assumed that most of the charging will occur at home in the evening hours. Figure 4.5 shows the electric vehicle forecast.

Figure 4.5 – Electric Vehicle Load Forecast

Year	Total Vehicle (MWh)	Summer Peak Impact (MW)	Winter Peak Impact (MW)
2024	691	0.0	0.0
2025	1,808	0.1	0.3
2026	3,500	0.2	0.5
2027	6,069	0.3	0.8
2028	9,972	0.5	1.4
2029	15,909	0.7	2.2
2030	21,251	1.0	3.7
2031	28,809	1.3	5.1
2032	39,752	1.8	7.0
2033	55,841	2.5	9.8
2034	79,773	3.6	13.9
2035	93,941	4.3	16.5
2036	109,076	7.6	19.1
2037	124,785	8.7	25.5
2038	140,262	9.7	28.5
2039	155,391	10.8	31.7
2040	170,208	11.8	34.7
2041	184,488	12.8	37.6
2042	199,831	13.9	40.7
2043	216,348	15.0	44.1
2044	234,119	16.3	47.7

4.5.3 Potential Effects of EVs on Generation, Transmission and Distribution

Electric Vehicles and their associated charging stations currently have a minimal impact on the CEI South electric system and therefore have not caused significant operational issues. As the level of EV charging stations increases, CEI South may encounter multiple operational issues that will need to be evaluated and potentially mitigated. Some examples of potential issues include:

- **Shifting Peak Load** – Increased use of EV will have an impact on the magnitude of daily load demand, as well as the timing of peak loading. If a large concentration of EV charging occurs in the late afternoon and early evening, the daily system peak could be shifted to later in the afternoon or a second (and most likely lesser) peak could occur in the evening.
- **Generation Reserves** – If EV charging largely occurs in the evening or overnight, the electric system would see higher than typical load demand values at times when DG and other solar generation installations would not be available. This would lead to a need for generation support during these hours, such as energy storage facilities, quick start generators, etc.
- **Peak Charging** – If a large portion of EV charging were to occur during peak loading times, the impact of the increased demand could lead to overloaded electrical infrastructure, unless some form of delayed or managed charging is available. These overloaded facilities would need to be upgraded or other system level upgrades would be needed to mitigate the overload conditions.
- **Transmission Planning Concerns** – MISO performs economic studies annually using a range of potential futures. The futures that they are currently evaluating include potential increases in electrification (including EV) at various growth levels. Due to the uncertainty around EV adoption and the differing values being analyzed, uncertainties as to when to complete transmission system upgrades to support a higher level of system peak load due to EV adoption may be introduced. A need for additional planning models and sensitivity analysis would be required to evaluate these uncertainties and determine the appropriate time to perform the needed transmission system upgrades.

- **Dynamic Behavior** – The dynamic behavior of these loads while in a charging state during fault conditions and during re-energization post fault condition is an additional issue that will need to be evaluated. Research is still needed to properly reflect how these types of loads respond from a dynamic behavior perspective and may require additional dynamic modeling for planning studies.

If there is a substantial increase in EV adoption within the next 10 years, it is anticipated there would be a significant change in the system load profile. As an example, the system peak load hour could shift to later in the day. The load profile and generation expansion implications of the changing load shape suggest EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

4.6 ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP filing, 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, total energy requirements and peak demand are expected to average 0.7% annual 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 4.1 2022 CEI South Long-Term Electric Energy and Demand Forecast Report.

Figure 4.6 – Energy and Demand Forecast[26]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2022	4,815,801		1,019		802	
2023	4,725,478	-1.9%	1,010	-0.9%	738	-8.0%
2024	5,163,907	9.3%	1,087	7.6%	812	10.0%
2025	5,152,172	-0.2%	1,087	0.0%	810	-0.2%
2026	5,153,363	0.0%	1,088	0.1%	811	0.1%
2027	5,164,632	0.2%	1,092	0.3%	813	0.3%
2028	5,178,436	0.3%	1,095	0.3%	816	0.4%
2029	5,175,063	-0.1%	1,095	0.0%	816	0.0%
2030	5,178,761	0.1%	1,096	0.1%	817	0.2%
2031	5,199,311	0.4%	1,100	0.3%	821	0.5%
2032	5,238,099	0.7%	1,105	0.5%	828	0.9%
2033	5,254,460	0.3%	1,110	0.4%	831	0.4%
2034	5,277,650	0.4%	1,114	0.4%	836	0.5%
2035	5,304,282	0.5%	1,120	0.6%	841	0.6%
2036	5,345,573	0.8%	1,128	0.7%	849	1.0%
2037	5,377,724	0.6%	1,136	0.7%	855	0.7%
2038	5,418,448	0.8%	1,145	0.8%	862	0.9%
2039	5,455,497	0.7%	1,154	0.8%	869	0.8%
2040	5,493,803	0.7%	1,162	0.7%	875	0.8%
2041	5,518,739	0.5%	1,169	0.6%	880	0.5%
2042	5,551,532	0.6%	1,177	0.6%	886	0.7%
CAGR 22-42		0.7%		0.7%		0.5%

4.7 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD and PEAK LOAD

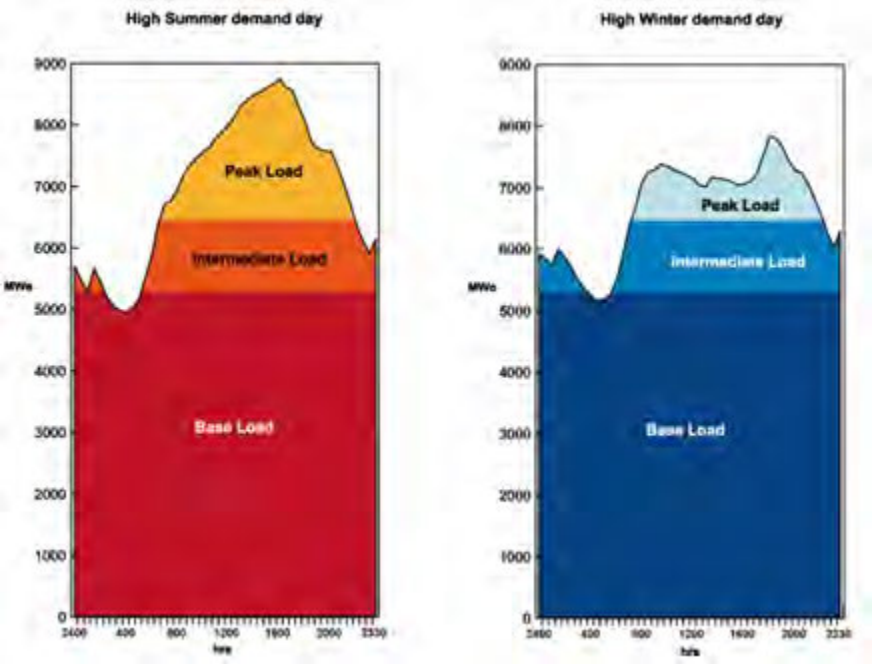
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level of demand. Plants can operate between extremes and generally have output increased in the morning and decreased in the

[26] 2022/2023 IRP energy and demand forecast will differ from what is provided to MISO to match MISO's requirements, particularly the treatment of EE, which is netted out of load

evening. Peak load is the highest level of demand within a 24-hour period. The annual peak hour is typically between June and September, when weather is hottest. For modeling purposes, CEI South uses August as the peak summer month and January as the peak winter month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.7 – Typical Load Curve Illustrations (Summer and Winter)



This dynamic is evolving as more intermittent renewable resources, particularly solar, come online. MISO nets out energy produced from renewable resources from customer load. This is expected to shift the net peak into the evening hours where dispatchable resources will be needed to serve customer load.

4.8 STAKEHOLDER INPUT – Load Forecast

CEI South discussed the load forecast data and process initially with stakeholders in the August 18, 2022, stakeholder meeting, providing an opportunity to provide input, question and comment on the draft load forecast before finalizing. On October 11, 2022, in the second public stakeholder meeting, CEI South followed up with the reference case load forecast, providing details on inputs (forecast drivers) for residential as well as commercial and industrial sales. Itron provided details about the structure of the models used and outputs for customer owned distributed generation and electric vehicles and answered stakeholder questions. Additionally, the peak load forecast was provided, along with relevant details.

SECTION 5
The MISO Market

5.1 MISO

Midcontinent Independent System Operator ("MISO") is the independent, not-for-profit Regional Transmission Operator ("RTO") of which CEI South is a member. MISO oversees power delivery across 15 states and the Canadian province of Manitoba and is one of the largest energy and operating reserves market in the world. MISO is divided into 10 Local Resources Zones ("LRZ"), Indiana is part of Zone 6, which includes northwest Kentucky (Big Rivers Electric Cooperative). Each LRZ has its own planning requirements regarding energy and capacity and can rely on neighboring Zones to an extent, largely depending on transmission infrastructure. Based on MISO's Local Clearing Requirement ("LCR"), which varies by season, approximately 60-80% of CEI South's generation must be physically located within MISO Zone 6.

Figure 5-1 – MISO Local Resource Zones



MISO's two main roles are transmission planning and oversight of its energy, capacity and ancillary service markets. MISO has operational authority to control transmission facilities and coordinate security for its region to ensure reliability. MISO is responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load needs.

5.2 MISO Planning Reserve Margin Requirement ("PRMR")

MISO requires CEI South and its other member electric utilities to maintain a seasonal PRMR. The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in 10 years and is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during seasonal peak periods, including peak periods where some equipment might fail. To further ensure the NERC standard of one loss of load event in 10 years, the PRMR is further detailed by the 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 amount 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. As a result, long term dependence on the market for capacity and energy has considerable risk.

The illustration in Figure 5.2 below shows the load on a typical day and load on the peak day with the reserve margin requirement. Figure 5.3 shows historical PRMR by year since 2015.

Figure 5-2 – Illustration of Load Curve and Planning Reserve Margin

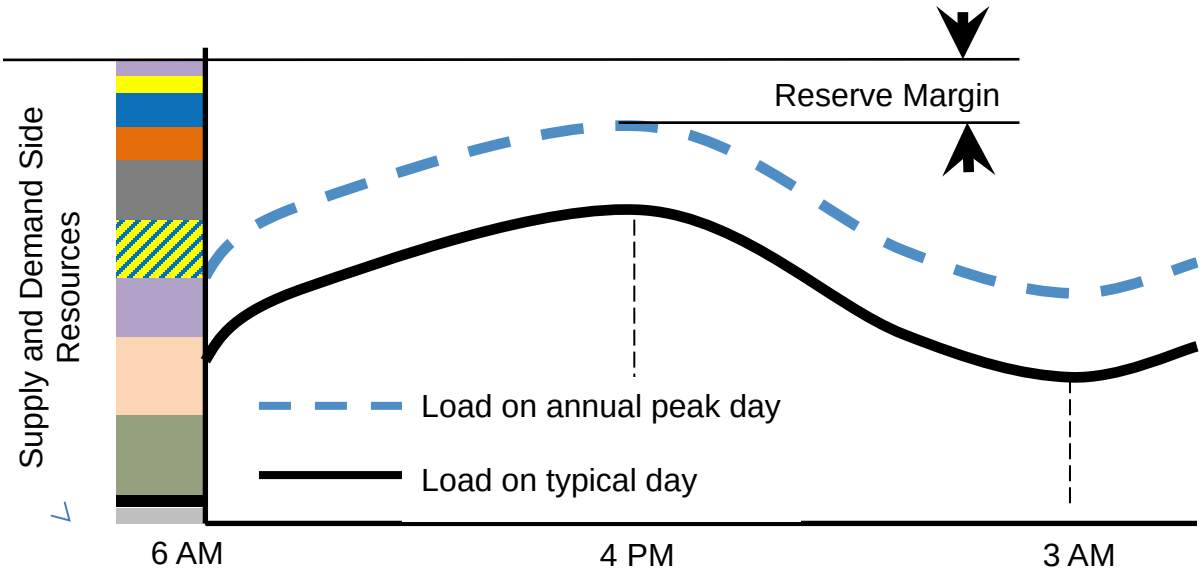


Figure 5-3 – Historic MISO PRMR

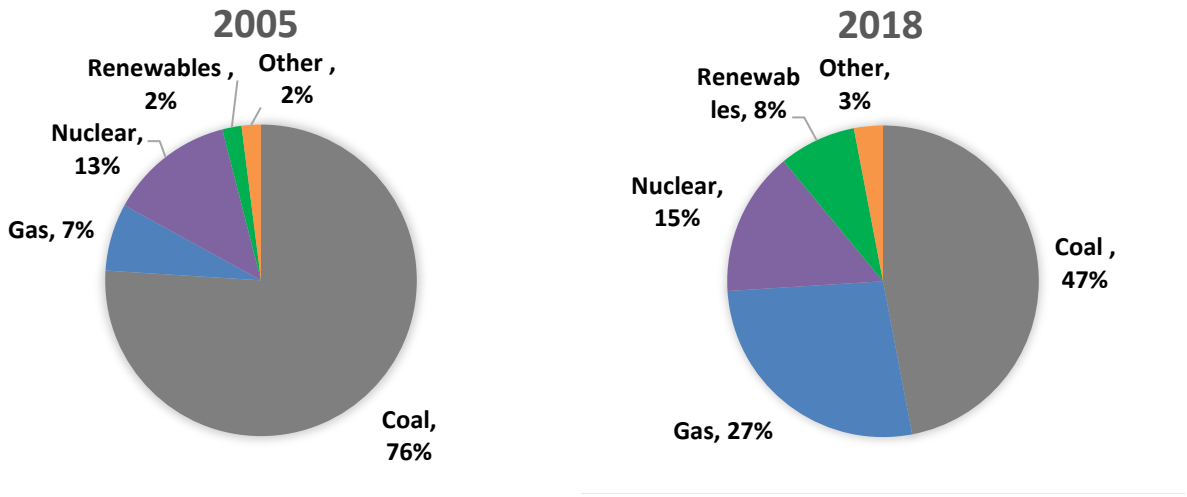
Planning Year	MISO PRMR (UCAP)-Required	MISO PRM (UCAP)-Excess Available: Offered/PRMR
2022-23	8.70%	136,906/135,326: 1.17%
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: 4.46%
2015-16	7.10%	145,861/136,359: 6.97%

5.3 MISO Resource Mix – Past, Current and Future

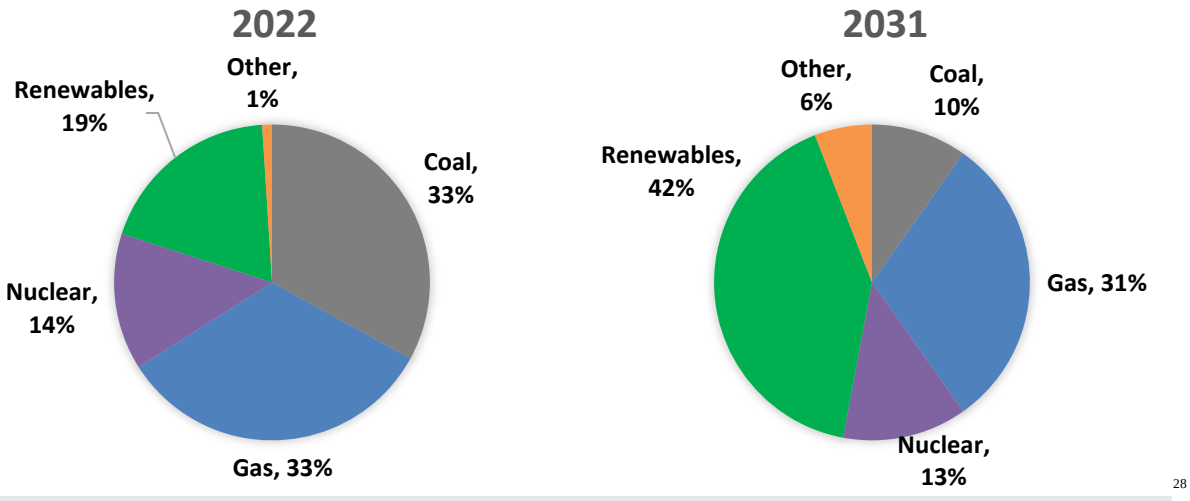
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of MATS, the release of the Clean Power Plan and various other regulations, and due to increasing cost pressure

from low gas price and declining renewable energy prices, MISO member companies began retiring aging coal units. As a result, its share of the MISO fuel mix dropped to 47%, with natural gas becoming the second leading fuel source and renewables quadrupling in size. In 2022 natural gas and coal (33%) are the leading fuel sources in MISO, followed by renewables (19%), while nuclear has decreased to 14%. MISO now projects by 2031 renewables will be the leading fuel source of MISO energy at 42%, followed by gas at 31% and coal decreasing to 10%.

Figure 5-4 – MISO Fuel Mix[27]



[27] Sources: 2005 Mix: MISO Evolution of the Grid presentation on 11/07/17; page 4 https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf
2018 Mix: MISO 2019 MTEP https://cdn.misoenergy.org/MTEP19468493.zip
2022 Mix: MISO Corporate Fact Sheet accessed 04/23 https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
2031 Mix: MISO 2022 Regional Resource Assessment – November 2022 – Page 6 https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf



[28]

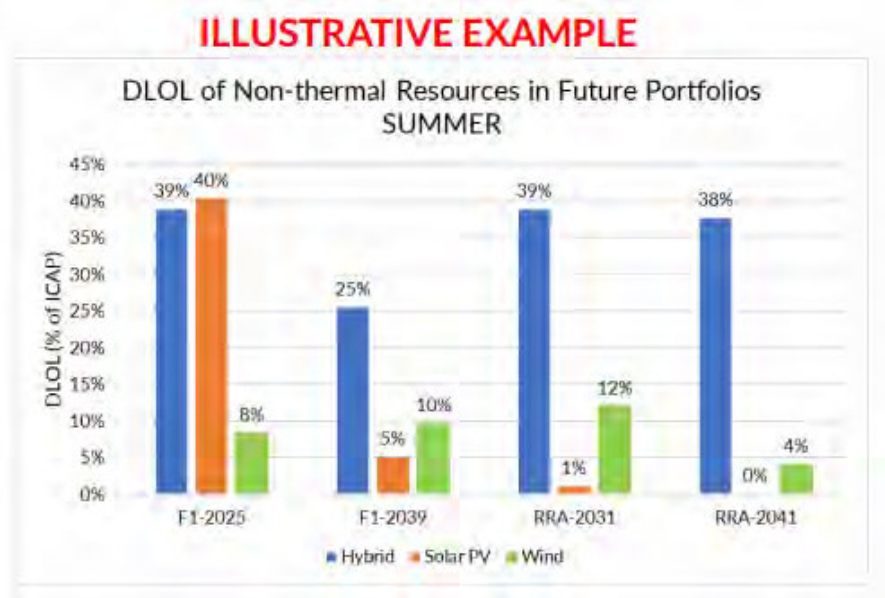
5.4 Dispatchable vs. Intermittent

Dispatchable generation refers to sources of electricity that can be used or dispatched on demand at the request of the power grid operator. Intermittent generation is associated with renewable forms of electricity, mainly solar and wind, which cannot be dispatched at a moment's notice and without storage capabilities only generate electricity as available. Dispatchability of a generation resource allows for planning that is reflected in capacity accreditation, which provides a generator an annual value based on: demonstrated generator capability and the past three years of operational availability during the periods of highest risk and greatest need (resource adequacy hours). Lack of dispatchability creates planning challenges best illustrated through the recent increase in MISO Emergency Max-Gen Events that have occurred throughout the four seasons as the reliance on intermittent resources has increased. An intermittent resource that may be capable of 100% of nameplate generating capacity on a certain day may be reduced to 0% of capacity during another hour of that same day due to a weather pattern. This volatility of intermittent renewable resources has challenged grid planners as these resources have been added to the system. Dispatchable resources that are not on outage remain available as called upon during these severe conditions when intermittent resources do not meet planned output.

[28] Values are presented by MISO total 102%

MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 76%[29] currently and is forecasted to be greater than 40%[30] renewables in 2031. In response to these conditions MISO commenced its Resource Availability and Need ("RAN") Initiative and its Renewable Integration Impact Assessment ("RIIA") to plan market rule changes to deal with the future resource mix. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them. While MISO continues to evaluate methodologies for future intermittent resource accreditation, it has signaled accreditation will likely decline over time, particularly for solar resources, as more renewable resources are brought into service. Figure 5.5 shows a recent slide presented in the MISO Resource Adequacy Subcommittee ("RASC"), which provides some possible direction for how non-thermal resources may be accredited in the future.

Figure 5-5 – Direct Loss of Load of Non-Thermal Resources[31]

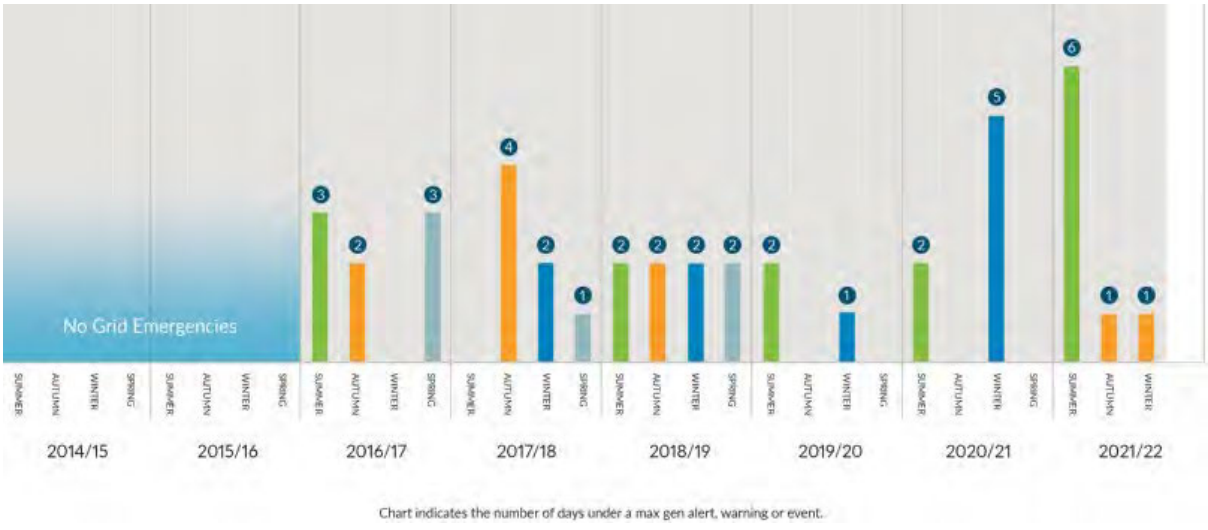


[29] MISO Corporate Fact Sheet accessed 04/23 - https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
[30] 2022 Regional Resource Assessment – November 2022 – Page 22 - https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf
[31] MISO; March 1, 2023 Resource Adequacy Subcommittee – Market Redefinition: Accreditation Reform; Page 12 - https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2009a%20Non-Thermal%20Accreditation%20Presentation628030.pdf

5.5 MISO Maximum-Generation Emergency Events

Maximum-Generation ("Max-Gen") Events are the final step in MISO's emergency operating procedure before firm-load shed, otherwise known as blackouts. Max-Gen Declarations have become more common over the last 6 years as shown in Figure 5.6. In January of 2019, MISO, for the first time in its existence, interrupted energy service to Industrial Customers enrolled as Load Modifying Resources ("LMR"). In recent years MISO's Planning Reserve Auctions has seen a higher percentage of LMRs and are projected to be needed to maintain system reliability during extreme events. Going forward customers enrolled as LMRs must consider the increased possibility of future interruptions. It is likely some LMRs will end their participation due to the heighted risk. Beginning in the 2023/2024 Planning Year LMRs must have a notification time equal to or less than six hours and be capable of being interrupted for: (i) at least the first five(5) times requested in the Summer Season; (ii) at least the first five (5) times requested in the Winter Season; (iii) at least the first three (3) times requested in the Spring Season; and at least the first three (3) times requested in the Fall Season.

Figure 5-6 – MISO Max Gen Declarations Over the Past 6 Years[32]



[32] https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf - Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct – November 30, 2021 – Page 3

5.6 MISO Resource Adequacy Reform

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, MISO implemented its RAN initiative. The goal of this initiative is to identify near-term solutions to increase the conversion of committed capacity resources into energy during times of need. A dramatically changing landscape has made this conversion process challenging. Therefore, MISO and its stakeholders identify and meet the challenges that guide longer-term preparations and near-term enhancements posed by current and future portfolio and technology changes facing the region.

The RAN initiative has led to market mechanism reform which is currently underway. Such reform has included implementation of a sub-annual resource adequacy construct consisting of four separate seasonal reserve margin targets and capacity auctions to better reflect variation in capacity accreditation and capacity needs across the year. Figure 5.7 below shows the PRMR by season for the 2023/2024 planning year.

Figure 5-7 – PRMR for the 2023/2024 Planning Year

Planning Season	MISO PRMR Required (SAC)[33]
Summer	7.4%
Fall	14.9%
Winter	25.5%
Spring	24.5%

The construct is predicated on four three-months seasons accounting for special attributes such as winter weatherization which will allow the capacity resources "must offer" requirement to be applied only to the seasons for which the capacity resource is

[33] MISO Planning Year 2023-2024 Loss of Load Expectation Study Report – Page 4 – May 3, 2023 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

cleared to allow units to operate seasonally. Concurrently MISO revised its (thermal) resource accreditation to reflect real-time availability and seasonal performance of generation assets to mitigate reliability risks while improving coordination of planned outages. The revisions process includes a two-tiered weighing approach to emphasize availability during tight critical need periods (Tier 2) but also availability in non-tight hours (Tier 1).

In the 2023-2024 planning year MISO transitioned from its existing annual construct to a four season construct to help ensure system needs are met in all seasons, and hours, of the year. In this new construct resource accreditation, peak demand, and planning reserve margin vary from season to season. CEI South integrated MISO's seasonal construct into the IRP analysis to ensure resource adequacy requirements were met in all seasons with limited capacity purchases over the planning period

Due to the growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, MISO determined its existing accreditation methods for non-thermal resources require further evaluation to ensure the accredited capacity value reflects the capability and availability of the resource during periods of highest reliability risk. MISO has developed a proposal that is currently under review by stakeholders which recommends accrediting wind and solar resources based on performance during Resource Adequacy Hours (65 hours in any season during which the capacity is tight. Sixty-five is the top 3% of the total hours (2190, 8760 divided by 4) in any given season) and adjusting unit accreditation to a class capacity value that is derived by using the Direct-Loss of Load ("Direct-LOL") method (taking a generation resource's availability during Loss of Load ("LOL") hours and average the output, using the sum of average availability for the entire resource class). MISO plans to file a final recommendation to FERC in Q4 2023.

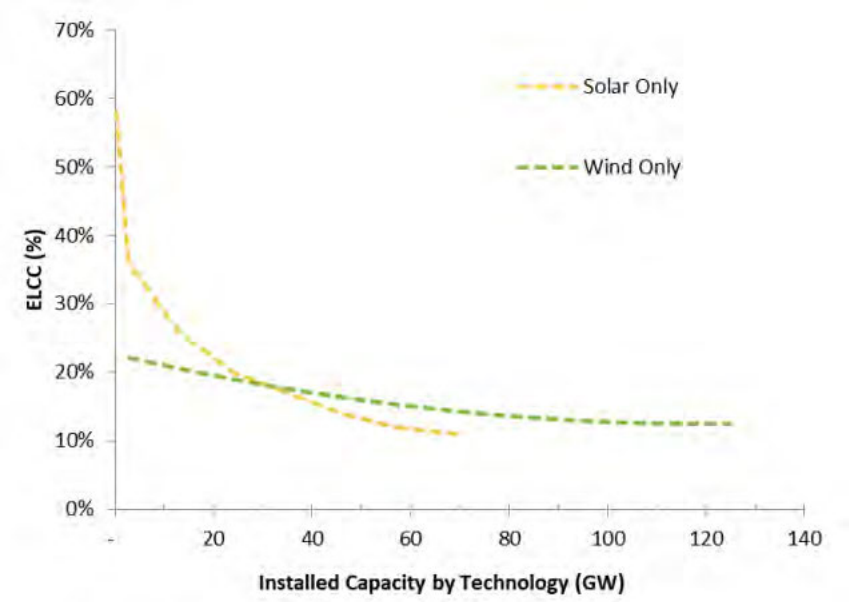
5.7 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit towards MISO's resource adequacy requirement based on their ability to reliably contribute energy during

the peak hours in each season. Thermal generation, such as natural gas and coal-fired power plants, can produce an expected level of output when called upon. For this reason, utilities can count nearly the full installed capacity of thermal generation towards their resource adequacy requirement (less their historical outage rate). A new thermal generator can count ~90 MWs out of every 100 MWs of installed capacity towards meeting MISO's planning reserve margin requirement in all seasons. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Because neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, they receive less capacity credit.

While renewable wind resources produce a lot of renewable energy over the course of the Planning Year, their capacity accreditation is typically a lot lower than dispatchable generation. MISO calculates the capacity which will be accredited for wind resources by calculating the resources' Effective Load Carrying Capability ("ELCC"). Wind resources located in MISO Zone 6 receive a capacity credit of only ~8%-~20% for the summer and winter respectively, meaning for every 100 MWs of installed wind capacity, 8 MWs count toward meeting the summer planning reserve margin and 20 MWs would count towards meeting the winter planning reserve margin. As part of MISO's RIIA, MISO evaluated the ELCC of wind and solar resources as penetration levels increased. Renewable penetration is expected to increase as shown in Figure 5.4. Renewable penetration increasing results in the net peak load shifting. This shift results in lower renewable energy production coincidence with the net peak load and therefore a lower ELCC accreditation as seen in Figure 5-8.

Figure 5-8 – Decreasing Solar and Wind ELCC as More is Installed[34]

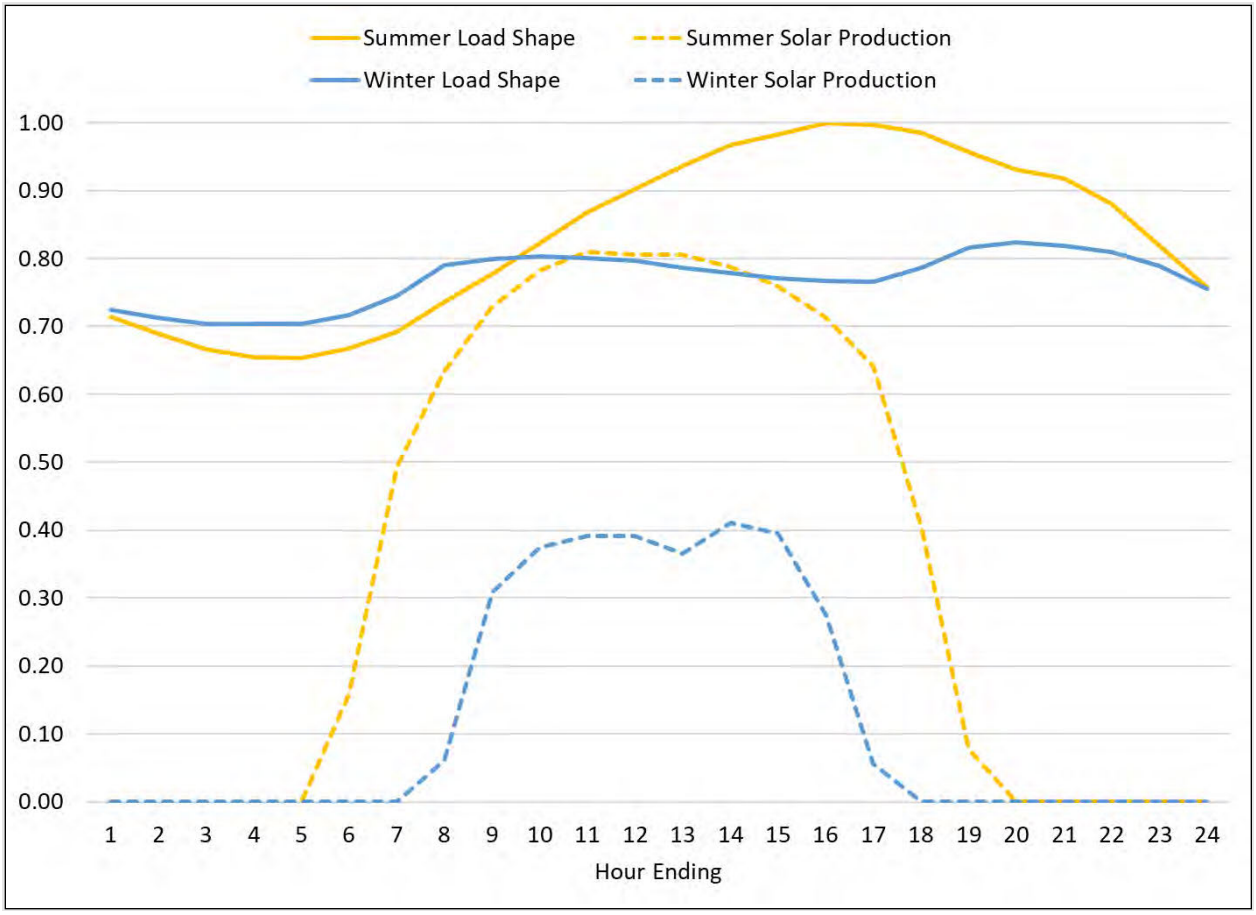


The solar and wind accreditation used in the IRP modeling was calculated using MISO's ELCC accreditation formulas and adjusted based upon the level of renewable penetration expected on MISOs system. As additional renewable resources were included in the model the UCAP accreditation for these resources was adjusted. Over time, this results in lower accreditation values.

Wind and solar capacity factors and energy coincidence with the net peak load vary seasonally. A Solar PV production chart comparison for the winter and summer is shown in Figure 5-9. It shows solar output has a higher coincident with peak demand in the summer months than winter months, due to not only the lower winter solar production, but also the typical peak demand occurring during non-daylight hours. These combined effects result in lower solar winter capacity accreditation.

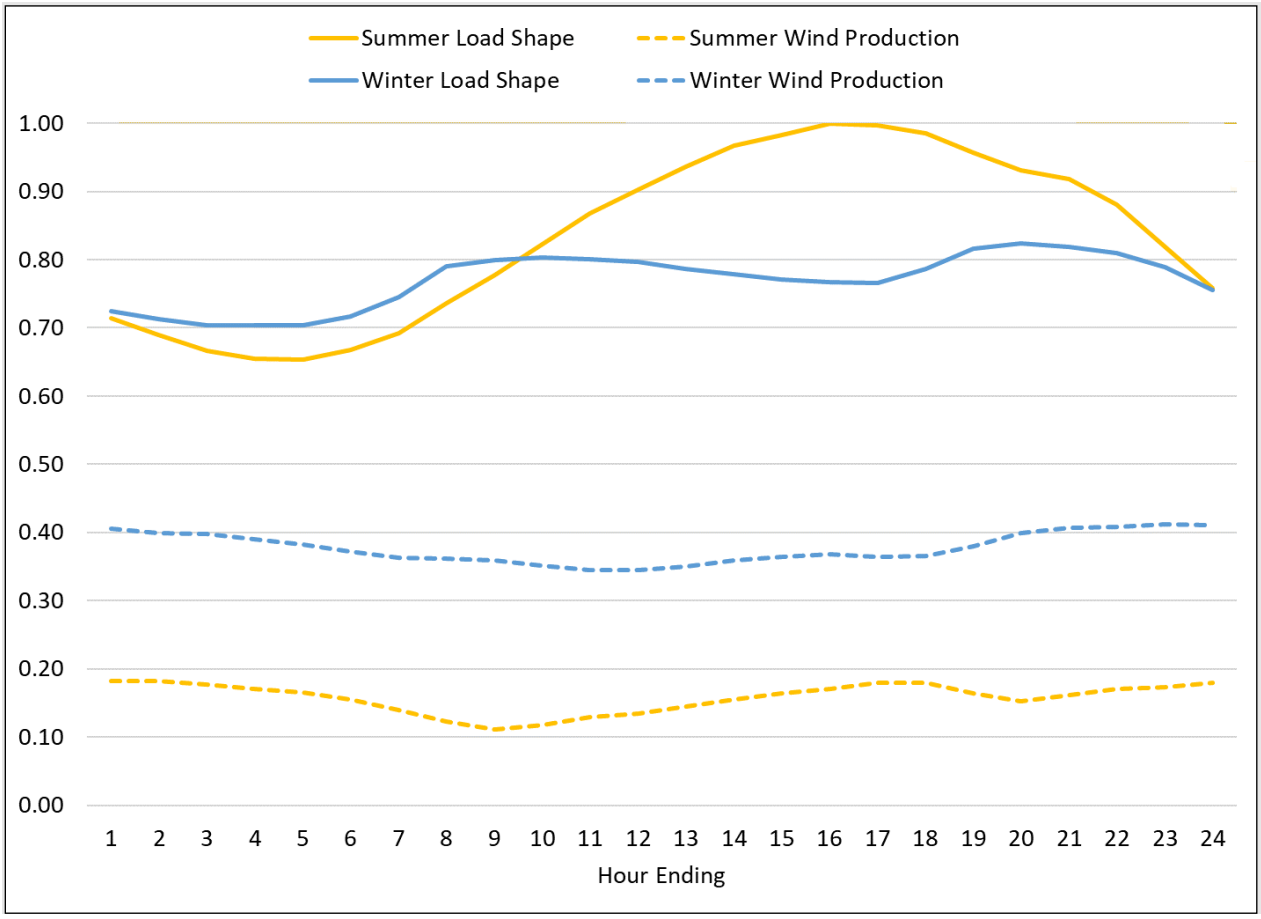
[34] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report February 2021, MISO, page 29, https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Figure 5-9 – Average Solar PV Energy Production Summer Verses Winter



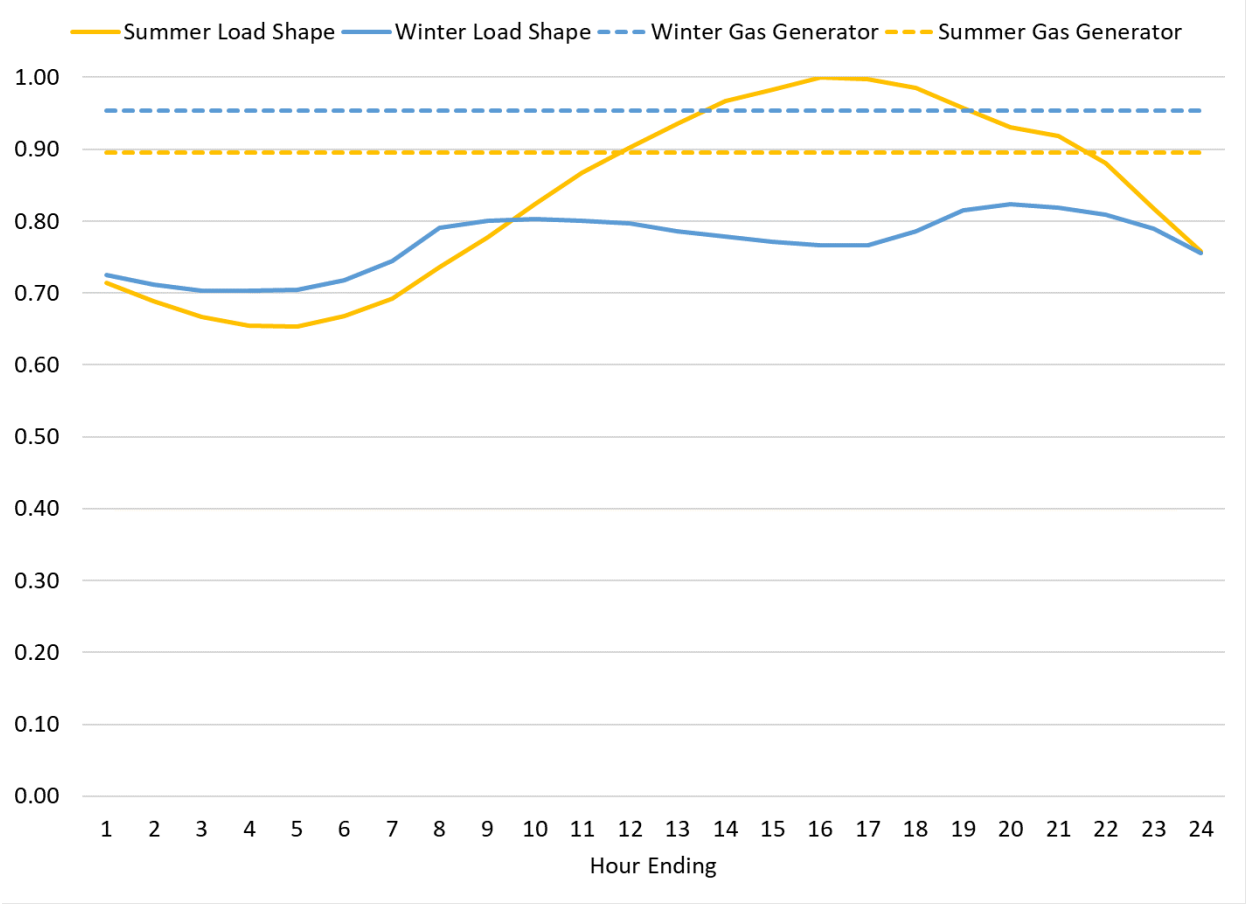
Wind resources typically have higher capacity factors during winter months leading to a higher output during winter peak demand hours. Summer and winter wind production compared to load shapes are shown in Figures 5.10.

Figure 5-10 – Average Wind Energy Production Summer Verses Winter



Gas resources are dispatchable generation; the benefit from being able to turn on and off as needed with exception to unit outages results higher capacity accreditation than non-dispatchable intermittent resources. For reference, a typical gas resource seasonal capability difference is shown in Figure 5-11.

Figure 5-11 – Average Gas Resource Energy Production Summer Verses Winter



MISO has moved to a seasonal PRMR requirement, as discussed in Section 5.6, and therefore resources as part of this IRP have been accredited on a seasonal capacity credit basis.

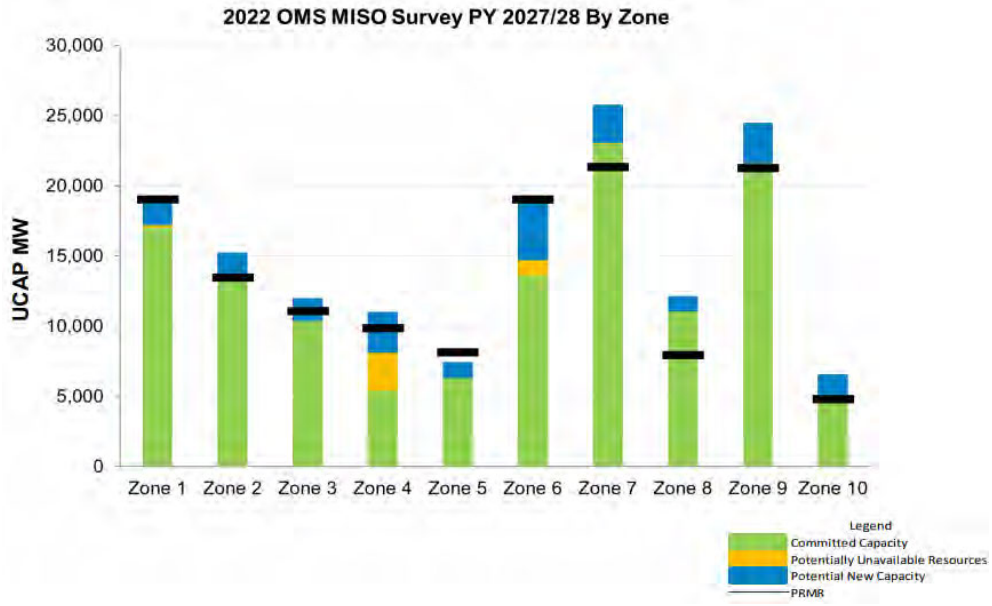
5.8 MISO Capacity

Historically, the price for capacity in MISO's annual auction has been volatile. The Organization of MISO States ("OMS"), of which the IURC is a participant, and MISO partnered to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has functioned as the main vehicle in communicating to the MISO stakeholder

community the anticipated PRM for upcoming years and is a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned there may be inadequate capacity within the MISO footprint at some future date which became reality in the 2022-2023 auction with a clearing price set at CONE, the maximum clearing price. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. Figure 5.12 illustrates Zone 6's increasing proportion of the entire MISO region shortfall projection and thus increased reliance on neighboring state generation resources. To increase the accuracy of the projection, the OMS and MISO have updated the methodology to project which resources are considered high certainty. With these improvements in place since 2017, there is still a projected shortfall. This shortfall is concerning, especially from a zonal standpoint that shows an increasing number of zones projecting a capacity shortfall.

Figure 5-12 –OMS MISO Resource Adequacy Survey Results Graph



According to the latest OMS survey, Indiana Zone 6 is one of the zones most at risk of a shortfall with a projected capacity deficit of approximately 4 GWs in the 2027-2028

planning year. It is worth noting MISO stated in the 2022-2023 PRA Results presentation "Unless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue." [35] The conversion of F.B. Culley 3, two existing CTs, and the addition of two fast-start, quick ramping CTs to natural gas will continue to provide the reliable capacity MISO and CEI South's customers need to support the build out of renewable resources. The table below demonstrates the projected shortfall for the MISO region and Zone 6 has more than doubled since 2018.

Figure 5-13 –OMS MISO Resource Adequacy Survey Results Table

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, 5-Year Projected	MISO-wide Resource Adequacy Shortfall, 5-Year Projected
2014	No 5-year projection provided	5.8 GW shortfall in 2019
2015	1.1 GW shortfall in 2020	2.3 GW shortfall in 2020
2016	800 MW shortfall in 2021	2.6 GW shortfall in 2021
2017	400 MW shortfall in 2022	No shortfall projected
2018	1.6 GW shortfall in 2023	4.5 GW shortfall in 2023
2019	2.4 GW shortfall in 2024	2.3 GW shortfall in 2024
2020	3.4 GW shortfall in 2025	6.8 GW shortfall in 2025
2021[36]	3.9 GW shortfall in 2026	0.8 GW shortfall in 2026
2022	≈4 GW shortfall in 2027	10.9 GW shortfall in 2027

5.8.1 Capacity Prices

The projected capacity shortfalls can result in volatile capacity prices. MISO's Planning Resource Auction ("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 5.14 below. These large swings in prices have made it difficult to forecast forward year prices.

[35] 2022-2023 MISO PRA Results - https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf – Page 11

[36] Prior to 2021 MISO showed capacity position on an ICAP basis; In 2021 MISO switched to a UCAP basis

While the 2020-2021 capacity price was relatively low, all zones in MISO's north/central region cleared at CONE ($236.66/MW-Day) in the 2022-2023 PRA.

Figure 5-14 –MISO Capacity Prices

Planning Year	Highest Clearing price for MISO-region	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[37]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$1.05	$383.25	-
2014-2015	$16.75	$16.75	$6,113.75	1,495% Increase
2015-2016	$150.00	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$72.00	$26,280.00	1,969% Increase
2017-2018	$1.50	$1.50	$547.50	98% Decrease
2018-2019	$10.00	$10.00	$3,650.00	567% Increase
2019-2020	$24.30	$2.99	$1,091.35	70% Decrease
2020-2021	$257.53	$5.00	$1,825.00	67% Increase
2021-2022	$5.00	$5.00	1,825.00	No Change
2022-2023	$236.66	$236.66	86,380.90	4,633% Increase

As shown in Figure 5.15, the inaugural 2023-2024 seasonal PRA zone 6 cleared at $10.00 in the summer, $15.00 in the fall, $2.00 in the winter, and $10.00 in the spring, all in $/MW-Day. While prices cleared lower in the 2023-2024 auction when compared to the 2022-2023 auction, MISO noted in the presentation of 2023-2024 PRA results that delayed retirements and market participants making additional existing capacity available contributed to sufficient capacity being available for the auction. MISO also noted many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition.[38]

Figure 5-15 –Inaugural MISO Seasonal Capacity Prices

Planning Year	Highest Clearing price for MISO-region per MW-Year	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-day	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-year
Summer	$3,650	$10	$3,650
Fall	$21,612	$15	$5,475
Winter	$6,891	$2	$730

[37] MW/day is the amount customers are required to pay should they purchase capacity via the MISO Planning Resource Auction. For example, in the 2016-2017 planning year each MW cost $72 per day ($26,280 per MW annually).

[38] https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf – MISO Planning Resource Auction Results – May 19, 2023 – Pages 3 and 4

Spring	$3,650	$10	$3,650

MISO and the Independent Market Monitor have determined the absence of a sloped demand curve in the PRA results in inefficient market outcomes and inefficient price signals. In addition, they have warned the current vertical demand curve in the PRA has consistently produced clearing prices that are divorced from the marginal value of reliability and the capacity needs of the region. To ensure reliable grid operation by having adequate resources procured in a cost-effective manner MISO has proposed a Reliability Based Demand Curve ("RBDC") which will capture the incremental capacity above the planning reserve margin requirement reflecting the reliability value.

5.9 MISO Energy Prices

Energy prices in MISO increased significantly in 2022 but have since trended down closer to recent historical norms. Several weather-related events, a capacity shortfall in MISO's North Central region and elevated coal and gas prices combined to create volatile energy prices. In 2023 the natural gas reserves have grown, pushing down costs, resulting in more stable energy prices in the MISO market.

Figure 5-16 –MISO Clearing Prices (Indiana Hub/Henry Hub Yearly Averages – 2015-YTD April 2023)

Year	Indiana Hub Real Time ATC Average	YoY% Change	Indiana Hub Day Ahead ATC Average	YoY% Change	Henry Hub Average	YoY% Change
2015	$28.02		$28.67		$2.61	
2016	$27.94	-0.27%	$28.11	-1.94%	$2.49	-4.60%
2017	$29.30	4.86%	$29.38	4.50%	$2.96	19.10%
2018	$32.99	12.59%	$33.19	12.97%	$3.12	5.36%
2019	$26.41	-19.95%	$26.98	-18.72%	$2.51	-19.41%
2020	$22.30	-15.55%	$22.97	-14.86%	$2.03	-27.05%
2021	$39.45	76.9%	$41.21	79.45%	$3.89	91.63%
2022	$71.47	81.18%	$70.22	70.37%	$6.45	65.81%
YTD 2023	$31.17	-56.39%	$32.54	-53.66%	$2.53	-60.78%

Over time, it is expected natural gas prices will increase, but remain relatively low and stable, keeping energy prices low.

5.10 MISO Interconnection of New Resources

Before a new generating facility can connect to the grid, the reliability impacts associated with interconnection must be studied. Issues uncovered during this process can be mitigated through electric transmission Network Upgrades ("NU"). The addition of upgrades to address system reliability have the potential to increase the costs associated with a new generating facility.

The MISO Generator Interconnection ("GI") process is a three-phase study cycle that has historically been conducted once or twice annually but as the size of the queue has grown, the process has slowed.

The Generator Interconnection Process (GI) defines the steps an interconnection customer and MISO take to move interconnection requests through the interconnection queue. The process can result in an interconnection agreement that allows the customer to connect generation to the MISO grid. The Generator Interconnection Process (GI) is divided into three phases: Pre-Queue, Application Review and Definitive Planning.

The Definitive Planning Phase (DPP) is the final phase of MISO's generator interconnection study process, during which 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. Application and milestone payment requirements based on the size of the unit to be studied are required 45 days prior to the start of the study cycle.

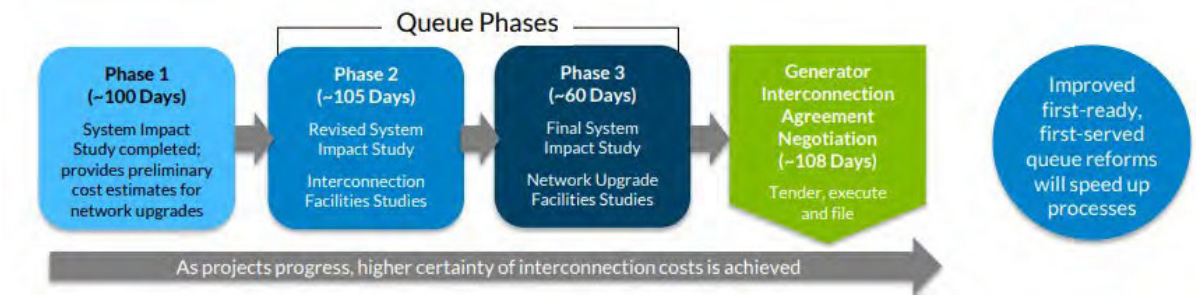
The DPP process is broken down into three phases and two decision points, following the completion of the first two phases (studies) the interconnection customer will once again have the chance to adjust the project size and move to the next phase as well as to withdraw from the queue. Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement ("GIA") process. Upon 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.

On March 15, 2022, MISO gained FERC's approval for a reduced Generator Interconnection Process ("GIP") timeline that decreased the time it takes to process interconnection study request from 505 calendar days to 373 days. Despite this approval, the MISO Generator Interconnection Queue process ("GIA/DPP") is experiencing significant schedule delays causing a great deal of uncertainty for interconnecting customers. Historically, MISO has only seen about a 20% success rate of all projects requesting interconnection, leaving customers entering the queue little certainty regarding interconnection cost or the timing for achieving deliverability, thus 80% of interconnection requests withdrawn from the queue. MISO acknowledges the current process is simply too long and will continue to work with stakeholders on interconnection process reforms.

As increased renewable development continues in order to qualify for tax incentives before expiration, the number of GI requests is not expected to subside and as a result, the timeline is likely to remain delayed.

Figure 5-17 –Reduce GIP Timeline (DPP Process)[39]



[39] MISO; https://cdn.misoenergy.org/20221206%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2004%20Generator%20Interconnection%20Queue%20Update627220.pdf; Generator Interconnection Queue Update, System Planning Committee of the Board of Directors, December 6, 2022; page 6

GI costs are determined based on the MW impact from each project on identified constrained facilities. As such, cost allocation is assigned to the generator that causes or contributes to a constraint and therefore projects that are studied after prior cycles are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying in later cycles are more likely to be assigned higher costs as a result of prior projects connecting to and exhausting current transmission system topology. For this reason, existing interconnection rights are valuable. MISO allows for an expedited process for new generation with existing interconnection rights; this helps to shield customers from potential upgrade costs. CEI South has continued the interconnection transfer process at A.B. Brown coal units 1&2 to new combustion gas turbine units 5&6. This process is anticipated for F.B. Culley 3 from a coal unit to one that is fired by gas. Bypassing the interconnection queue decreases timing and cost risk for CEI South customers.

SECTION 6
RESOURCE OPTIONS

6.1 ALL-SOURCE RFP

The All-Source RFP was conducted according to the schedule outlined in Figure 6.1. More details on the steps included in the RFP timeline are described below.

Figure 6-1 RFP Timeline

Step	Date
RFP Issued	Wednesday, May 11, 2022
Notice of Intent, NDA, and Respondent Application Due	5:00 p.m. CDT, Friday, May 27, 2022
Pre-Bid Meeting	3:00 p.m. CDT, Wednesday, June 1, 2022
Proposal Submittal Due Date	5:00 p.m. CDT, Tuesday, July 5, 2022
Initial Proposal Review and Evaluation Period	Wednesday, July 6, 2022 – Thursday, August 11, 2022
Proposal Evaluation Completion Target and Short List to CenterPoint	Friday, August 12, 2022
Due Diligence and Negotiations Period	Q3-Q4 2022

6.1.1 RFP Issued

1898 & Co. issued the All-Source RFP on behalf of CEI South on Wednesday, May 11, 2022 (http://CenterPoint2022ASRFP.rfpmanager.biz/). Notice was sent to all known IRP stakeholders and posted on www.midwest.centerpointenergy.com/IRP. The RFP was advertised across multiple media outlets, including, North American Energy Markets Association ("NAEMA") (190 members) and Midwest Energy Efficiency Alliance ("MEEA") Minute (161 members). It was also sent directly via e-mail to participants of CEI South's 2019 All-Source RFP, an internal 1898 & Co. RFP contact list (more than 900 recipients), and CEI South industry contacts. Several industry publications, including S&P Global, also published articles about the RFP. While the RFP included general requirements and communicated Proposals which do not meet the general requirements may be subject to disqualification, all were included for evaluation. For more details, please refer to the submitted CEI South 2022 All-Source RFP in Technical Appendix Attachment 6.3.

6.1.2 Notice of Intent

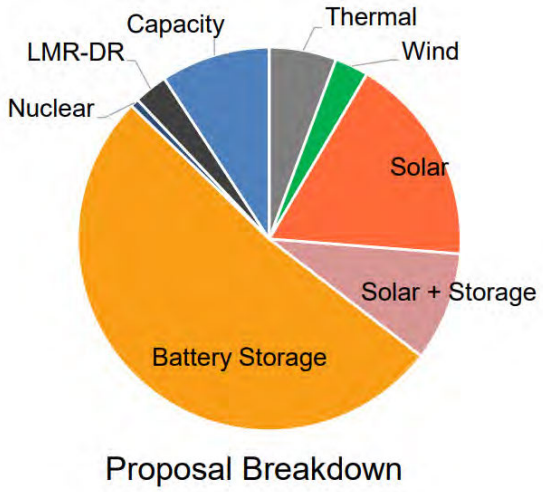
Respondents were given two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify Respondents have adequate experience and financial capability to support their Proposal(s).

6.1.3 Proposal Review

The Proposal Submittal Due Date was Tuesday, July 5, 2022. After all Proposals were received, 1898 & Co. began the Initial Proposal Review. While Proposals were being reviewed, information was clarified with Respondents to confirm Proposals were interpreted as intended.

A total of 142 Proposals were received from 29 Respondents. The Proposals comprised 62 battery storage, 5 thermal, 4 LMR/DR, 42 solar, 15 solar plus storage, 4 wind, 9 capacity only, and 1 thermal plus solar. Of the 142 Proposals, 108 were in Indiana. The Proposals contained approximately 20 GW of total installed capacity; however, many of the projects were included in multiple proposals. There was approximately 7.5 GW of unique project installed capacity after accounting for double counting. For example, a single 100 MW solar project could be offered as a purchase option or various PPA options. A graphical overview of all Proposals received is shown in Figure 6-2.

Figure 6-2 Breakdown of Proposals Received



2022 RFP Responses	Proposal Installed Capacity (MW)	Project Installed Capacity (MW)
Thermal	3,087	1,909
Battery Storage	10,149	1,651
Solar + Storage	2,700	1,400
Capacity	632	557
Solar	2,588	1,529
LMR-DR	64	63
Wind	800	400
Total	20,019	7,508

6.1.4 Proposal Updates for Inflation Reduction Act (IRA)

Shortly after Proposals were submitted for the 2022 All-Source RFP, the IRA was passed into law on August 16, 2022. This law provided additional tax structures and incremental benefits for renewables and other energy projects that met certain criteria. To determine the pricing impact, participants in the RFP were asked to update their proposals on August 23, 2022 and have them resubmitted no later than September 7, 2022. Of the 142 Proposals, 77 were resubmitted with updated pricing to account for the IRA. Of the submitted bids, storage PPA's saw an average price decrease of 13%, solar PPA's 8% decrease, Solar plus storage PPA's 4% decrease, and wind PPA's 14% decrease.

6.1.5 MISO Interconnection

The appropriate MISO DPP Generation Interconnection Study Group was identified for each of the respective Proposals. For the Proposals that reside in Study Groups with posted DPP reports, the identified NU and associated costs were used.

For the Proposals that reside in Study Groups without posted DPP reports, the RFP asked for the bidder's estimate of interconnection costs, but these were not used in evaluation between Proposals to preserve objectivity in the comparison.

6.1.6 Grouping

Proposals were divided into groups based on technology type and ownership structure. Aggregated cost and performance information from the RFP Proposals was provided to the IRP team to facilitate portfolio modeling. There are many benefits to modeling the RFP bids in groups. These benefits include allowing the IRP modeling to help evaluate the technology, size, duration and mix of resources which would be included in the Preferred Portfolio. Given the volume of Proposals received as part of the IRP, it may not have been possible and would not have been practical to model each individual project. Moreover, it would be difficult to maintain confidentiality of individual projects. IRP modeling of individual projects does not holistically evaluate all relevant factors, such as locational differences of wholesale market pricing and potential congestion impacts. Using a grouping method allows for IRP inputs to reflect anticipated project costs.

6.1.7 Evaluation of Proposals

1898 & Co. quantitatively and qualitatively evaluated all conforming generation facility Proposals. Proposals were evaluated relative to others within the same grouping using the scoring criteria set forth in the RFP. The scoring criteria included four major categories: LCOE, energy settlement location, interconnection/development status and project risk factors.

Scoring of the individual RFP Proposals was not part of the IRP process. Scoring criteria has been provided for transparency to respondents and to demonstrate CEI South is serious about pursuing projects following the completion of the IRP analysis. CEI South does not believe RFPs should be conducted just to obtain market data. The Proposals were scored to aid in the selection process after the Preferred Portfolio results were

provided from the IRP. The Proposals were scored according to the criteria shown in Figure 6-3.

Figure 6-3 Scoring Summary

Scoring Criteria Name	Points		Definition/Allocation	Importance
LCOE Evaluation	150		$/MWh Calculation within asset class	An LCOE evaluation comparing similar resource groups will help to show which Project(s) may provide lower cost energy to CenterPoint customers
Energy Settlement Location	100		Proposals that include all costs to have energy financially settled or directly delivered to centerpoints load node. (SIGE.SIGW)	Having Financial settlement or direct delivery to CenterPoints load node provides Project's tru resource cost to CenterPoint's customers, eliminating risks/costs associated with the delivery of energy.
Interconnection and Development Status	100		•75 points completed Facilities Study (during DPP2-3) & offered cost cap •50 points competed System Impact Study (during DPP1) & offered cost cap •25 points offered cost cap •0 points otherwise	These points are for completion of various critical milestones in the interconnection and development process. Projects which are further through the interconnection and development process will receive more points as costs certainty improves.
Project Risk Factor - Renewable	150		•Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 •Development Experience – 30 points awarded proportional to MW in service, max of 1,500 •Site Control – 30 points proportional from 0%-100% of site control verified by provided docs •Permits – 30 points for proposals showing all permits needed for construction/operation •Zoning – 30 points for proposals showing completed zoning requirements	Certain risk factors may be unique to a Proposal. Such factors may be significant enough to independently impact the overall ability of the Proposal to meet CenterPoint's needs. This category is intended to capture unspecified risk that may be highlighted by a Respondent or identified during the Proposal review. The Project Risk Factors attempt to identify and score potential risks which may compromise the future performance of the asset.
Project Risk Factor - Thermal	150		•Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 •Development Experience – 30 points awarded proportional to MW in service, max of 1,500 •Fuel Risk - 15 •Operational Control – 15 •Site Control – 30 points proportional from 0%-100% of site control verified by provided docs •Permits – 15 points for proposals showing all permits needed for construction/operation •Zoning – 15 points for proposals showing completed zoning requirements	Operational control provides the ability to make prudent operational decisions when it makes economic sense for CenterPoints customers. Fuel restrictions or lack of reliable fuel could effect the operation of the Project and be a risk to the owner/off taker.

RFP bids were ranked consistent with the evaluation criteria and will be considered based on the RFP evaluation and the IRP determined need. Projects consistent with the IRP have undergone further due diligence and have led to negotiations with bidders. As such, there is no assurance the individual, highest-scoring qualified Proposal(s) will be selected. For further discussion of the evaluation criteria and results see Technical Appendix 6.3.

6.1.8 Challenges with Conducting an All-Source RFP within an IRP

While there are advantages to conducting an All-Source RFP as part of the IRP process, there are several challenges that must be considered, particularly the long lead time. Developers prefer certainty on project selection to minimize project development cost risk. Conducting an RFP as an input to the IRP necessitates a long process. CEI South believes, at a minimum, a year is needed to conduct an IRP analysis. While CEI South

asked bidders to keep bids open after bid submittal, this does not mean developers are able to wait until the process is complete.

As a result, some projects may be acquired by other load serving entities since typically individual projects are being bid into multiple utilities' RFPs. Competition for projects in MISO Zone 6 is steep with many utilities (NIPSCO, IPL, Hoosier Energy, IMPA and CEI South) currently all vying for announced projects that have more certainty of being developed.

As a project moves along, several issues can arise that increase cost estimates, including updated engineering identifying new costs, environmental permitting, local pushback, local permitting, updated interconnection costs, updated risk assessments by the developers, etc. On the contrary, the opposite can also happen. Due to the extraordinary market volatility in recent years, the market price of projects has risen significantly since the last RFP. Market uncertainty is also driving developers to price in the high-end of their risk resulting in project pricing that is much higher today than it was even two years ago.

6.2 CURRENT RESOURCE MIX

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. CEI South's larger coal units have historically operated as base load units but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. CEI South's coal units more recently have operated

more like intermediate units, 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 gas turbines 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.

CEI South's current generation mix consists of approximately 1,324 megawatts ("MW") of installed capacity. This capacity consists of approximately 995 MW of coal-fired generation, 160 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 54 MW of solar, Purchase Power Agreements (PPA's totaling 80 MW from wind), and a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

Figure 6.4 references both Installed Capacity ("ICAP") and Seasonal Accredited Capacity ("SAC"). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. 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 (7.4% for summer, 14.9% for fall, 25.5% for winter, and 24.5% in spring[40]) in the current IRP. This information was utilized to help ensure all portfolios met MISO obligations on a seasonal basis.

[40] Planning Year 2023-2024 Loss of Load Expectations Study Report; MISO; https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf ; Update 5/1/23; page 4

Figure 6.4 – CEI South Generating Units

Unit	Installed Capacity ICAP (MW)	Summer SAC (MW)	Fall SAC (MW)	Winter SAC (MW)	Spring SAC (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 1	245	228	N/A	N/A	N/A	Coal	1979
A.B. Brown 2	240	226	N/A	N/A	N/A	Coal	1986
F.B. Culley 2	90	87	90	88	83	Coal	1966
F.B. Culley 3[41]	270	215-270	191-270	199-270	270	Coal	1973
Warrick 4	150	142	150	N/A	N/A	Coal	1970
A.B. Brown 3	80	75	85	85	85	Gas	1991
A.B. Brown 4	80	73	72	76	84	Gas	2002
Blackfoot	3	N/A[42]	N/A[42]	N/A[42]	N/A[42]	Landfill Gas	2009
Oak Hill Solar	2	N/A[42]	N/A[42]	N/A[42][42]	N/A[42]	Sun	2018
Volkman Rd Solar	2	N/A[42][42]	N/A[42]	N/A[42][42]	N/A[42]	Sun	2018
Troy Solar	50	37	25	2	32	Sun	2021

*Installed capacity shown at 59°F

6.2.1 Coal

The A.B. Brown Generating Station ("ABB"), located in Mt. Vernon, Ind., consists of two coal fired units. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986. ABB Unit 1 has an installed capacity of 245 MWs and ABB Unit 2 has an installed capacity of 240 MWs. Over the last three years these units have operated at an average capacity factor of approximately 60%.

Both A.B. Brown units are scrubbed for sulfur dioxide ("SO_2") emissions, utilizing a dual-alkali Flue Gas Desulfurization ("FGD") process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide ("SO_3") is removed via Sodium Based Sorbents ("SBS") injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides ("NO_x") with Selective Catalytic Reduction ("SCR") systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury ("Hg") removal is

[41] Accreditation was lowered in the near term for Culley 3 to account for the unplanned outage in 2022/2023

[42] The Blackfoot landfill gas generator and 2 MW solar installations are connected at the distribution level and are not part of the transmission connected generation network managed by MISO. Therefore, they are not assigned a MISO UCAP value.

accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter ("PM") is captured via an electrostatic precipitator ("ESP") on Unit 2. PM control at Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly ash, is part of CEI South's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, Mo., where it is used in the manufacture of cement.

A.B. Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, Ind., and is delivered via rail. These units are scheduled for retirement late in 2023.

The A.B. Brown plant site also has two natural gas turbine generators which are discussed in Section 6.2.2, Natural Gas.

The F.B. Culley Generating Station ("FBC"), located near Newburgh, Ind., is a two-unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973. Over the last three years Unit 2 has operated at an annual capacity factor of 22% while Unit 3 was 48%.

FBC is scrubbed for SO_2 emissions, utilizing an FGD process which is shared by both units and was retrofitted in 1994. The captured SO_2 is converted into synthetic gypsum within the system and, as part of CEI South's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, La., and is shipped via truck to a facility near Shoals, Ind., where it is used in the manufacture of drywall. SO_3 is removed from FBC Unit 3 via a Dry Sorbent Injection ("DSI") system installed in 2015. FBC Unit 3 is also scrubbed for NO_x with a SCR system that was installed in 2003. NO_x control on FBC Unit 2 is provided by low NO_x burners. Mercury removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP retrofitted on Unit 2 in 1972. Unit 3 was

upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of CEI South's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, Mo., where it is used in the manufacture of cement. A Spray Dry Evaporator ("SDE") system was installed in 2023 to comply with the EPA's ELG. This system takes the wastewater stream from the scrubber and separates the solids and then injects the remaining liquid into the flue gas stream where it is evaporated resulting in a zero liquid discharge process.

The F.B. Culley units burn Illinois basin bituminous coal, which is mined in Knox County, Ind., and delivered via truck. F.B. Culley 3 is CEI South's most efficient coal unit.

Warrick Unit 4 (Warrick) located near Newburgh, Ind., is a coal fired unit operated and maintained by Alcoa Power Generating Inc. CEI South maintains 50% ownership of Warrick Unit 4. It has an installed capacity of 300 MW which began commercial operation in 1970. CEI South's 50% interest is equal to 150 MW. Over the last three years this unit has operated at a capacity factor of 70%.

Warrick Unit 4 is scrubbed for SO_2 emissions, utilizing a FGD process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system and (as part of CEI South's beneficial reuse program) is shipped via truck to a facility near Shoals, Ind., where it is used in the manufacture of drywall. SO_3 is removed via a DSI system installed in 2010. Unit 4 is also scrubbed for NO_X with a SCR system which was retrofitted in 2004. Mercury removal is accomplished as a co-benefit of SCR and FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP. The PM that is captured, also known as fly ash, is part of CEI South's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, Mo., where it is used in the manufacture of cement.

Warrick Unit 4 burns Illinois basin bituminous coal. CEI South purchases coal for its share of Warrick Unit 4, which is mined in Knox County, Ind., and is delivered by rail.

6.2.2 Natural Gas

The A.B. Brown Generating Station currently has two natural gas fired Simple Cycle Gas Turbine ("SCGT") peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002. Over the last three years Unit 3 has operated at a capacity factor of 3% with Unit 4 at 4%.

6.2.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, Ind., is a base load facility consisting of two Internal Combustion ("IC") landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each. Over the last three years these units have operated at a capacity factor of 38%.

The Oak Hill and Volkman Road universal solar projects in Evansville, Ind., became operational in 2018 with each location having an installed solar capacity of 2 MW. In addition to the solar capacity the Volkman Road site includes 1 MW of battery storage. These assets are located on the distribution system and are therefore netted out of CEI South's load for this analysis. Over the last three years these solar installations operated at an average annual capacity factor of 20%. The average annual capacity factor is affected by hours of daylight, cloud cover, temperature, etc.

The Troy solar facility located near Troy, Ind., began commercial operation in 2021. Single axis tracking panels were used for construction of the facility. Troy solar has an installed capacity of 50 MW and operated at a capacity factor of 24% in 2022.

6.2.4 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 two decades, but more recent technology is now making the program obsolete. Between 2010 and 2021, CEI South's DSM programs reduced demand by approximately 82,000 kW and provided annual incremental gross energy savings of approximately 427,000,000 kWh.

The table below outlines the estimated program penetration on a yearly 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 6.5 Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)*	Gross Cumulative Savings (GW)[43]	Percent of Sales Achieved (Cumulative)
2010	5,617	2.53	0.00075	0.04%
2011	5,595	19.4	0.00549	0.35%
2012	5,465	66.95	0.01347	1.23%
2013	5,459	128.64	0.02669	2.36%
2014[44]	3,499	175.98	0.03277	5.03%
2015	3,224	202.82	0.03682	6.29%
2016	3,256	236.4	0.0451	7.26%
2017	3,281	268.86	0.05047	8.20%
2018	3,491	309.28	0.05775	8.86%
2019	3,135	352.76	0.06645	11.25%
2020	3,176	396.79	0.07437	12.49%
2021	3,174	427.19	0.08212	13.46%

[43] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.
[44] 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.

6.2.4.1 2021-2023 Plan Overview

Consistent with the 2019 IRP, the framework for the 2021-2023 EE Plan was modeled at a savings level of 1.25% 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 2021-2023. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2021-2023 EE Plan detail found in the Technical Appendix Attachment 6.1 CEI South Electric 2021-2023 DSM Plan.

Residential Programs

- Residential Specialty Lighting
- Income Qualified Weatherization
- Appliance Recycling
- Residential Prescriptive
    - Residential Midstream, Marketplace, Instant Rebates
- Residential New Construction
- Residential Behavior Savings
- Smart Cycle (“DLC Change Out”)
- Bring Your Own Thermostat (“BYOT”)
- Community Based – LED Specialty Bulb Distribution
- Conservation Voltage Reduction (“CVR”) Residential

Commercial and Industrial Programs

- Small Business Direct Install
- Commercial and Industrial Prescriptive
- Commercial and Industrial New Construction
- Commercial and Industrial Custom
- Building Tune-Up
- Multi-Family Retrofit
- Conservation Voltage Reduction - Commercial

The 2021-2023 plan was included as an existing resource in the 2019/2020 IRP and has an assumed average measure life of 12 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 6.1 CEI South Electric 2021-2023 DSM Plan).

Figure 6.6 2021-2023 Energy Efficiency Savings

	2021[45]		2022[46]		2023[47]	
Sector	Net MWH Energy Savings	Net MW Demand Savings	Net MWH Energy Savings	Net MW Demand Savings	Net MWH Energy Savings	Net MW Demand Savings
Residential	13,640	3.1	10,810	2.8	13,404	3.2
C&I	16,279	4.3	12,432	2.2	25,169	3.7
Total	29,919	7.3	23,242	4.9	38,572	6.9

6.2.5 Demand Response

CEI South's tariff currently includes two active Demand Response ("DR") programs: 1) the Direct Load Control and 2) interruptible options for larger customers. Demand response programs allow CEI South to curtail load for reliability purposes. CEI South's tariff also includes a MISO DR tariff, in which no customers are currently enrolled. CEI South has engaged a DR aggregator who submitted a response to the All-Source RFP to explore DR potential based on customer load and industry demographics.

6.2.5.1 Current DLC (Summer Cycler)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps 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

[45] 2021 Evaluation Results used for 2021
[46] 2022 Evaluation Results used for 2022
[47] 2023 Operating Plan used for 2023 Savings

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 2023 Cadmus predicted that the DLC Program was capable of generating approximately 4 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control during MISO load curtailment events. This is roughly half of prior predictions, which were used for IRP modeling.

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 2022 had approximately 19,000 residential customers with 27,000 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.

6.2.5.2 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 has no remaining customers on the tariff registered as a resource with MISO. New MISO

testing requirements are in place to ensure DR resources are available throughout the year. MISO is proposing interruptible resource accreditation based on the amount of interruptions and available hours to curtail. MISO has already implemented mandatory annual testing that requires load interruptions to meet the test requirements. Prior to January 31, 2019, CEI South had never been requested by MISO to deploy LMRs, thereby interrupting customer load. While aggressive, CEI South maintained industrial interruptible load at the 25 MWs within the model throughout the analysis period, per stakeholder request and is exploring options to reach this level.

6.2.5.3 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.

Additionally, CEI South also launched the Bring your Own Thermostat ("BYOT") program as a DR program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2021-2023 Plan provides for approximately 500kW demand each year from the BYOT program based on approximately 500 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in DR and other load curtailing programs managed

through the utility. 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.

6.3 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

CEI South utilized the All-Source RFP for modeling inputs through 2027 for wind, solar, solar + storage resources. The following supply side information was based on a technology assessment from 1898 & Co. unless otherwise noted and was used to help provide needed information to model other resources where CEI South did not receive an RFP bid.

6.3.1 Supply Side

Resources are typically divided into supply side and demand side resources. Supply side simply means resources that produce energy.

6.3.1.1 Coal Technologies

Coal power plants, also known as Pulverized Coal (“PC”) steam generators, are characterized by pulverizing coal, then burning the coal in a boiler to create heat. The heat from the boiler is then used to turn water into high pressure steam which is used to turn the turbine causing the generator to create electricity.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3208 psia and 705°F, supercritical

units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

Proposed greenhouse gas ("GHG") regulations for new construction will limit CO_2 emissions to 1,100 lbs./MWh, a level which would require carbon capture on PC plants. Carbon capture on PC plants has been demonstrated in the field and as the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. See Figure 6-7 for further details on the coal technologies evaluated.

Figure 6-7 – Coal Technologies

Operating Characteristics and Estimated Costs	Supercritical Pulverized Coal with Carbon Capture	Ultra-Supercritical Pulverized Coal with Carbon Capture
Base Load Net Output (MW)	506	747
Base Load Net Heat Rate (HHV Btu/kWh)	11,290	10,480
Base Project Costs (2022$/kW)	$6,660	$6,020
Fixed O&M Costs (2022$/kW-year)	$32.01	$32.01

6.3.1.2 Natural Gas Technologies

Natural gas power plants are characterized by igniting natural gas and transforming the heat generated from combustion into electrical energy. Various forms of natural gas generation were evaluated in this IRP. Multiple existing and planned generation facilities were considered for conversion options. AB Brown 5 and 6 are approved to be built and operate as simple cycle combustion turbines, the conversion of these units to a 2x1 combined cycle was considered in the model. The addition of a heat recovery steam generator to capture waste heat results in a very efficient unit that would dispatch and run most of the time. In contrast, the conversion of F.B Culley 3 from firing on coal to natural gas, with firm supply, provides peaking generation and will not run much. It was considered at different points throughout the study period. Figure 6-8 and Figure 6-9 outline the details of these conversion options. Cogeneration was also evaluated through

this IRP process. Cogeneration, also known as combined heat and power, is the process of using waste heat to boil water and pump steam from the boiler into a generator. Electrical generation and heating water are produced from this process. See Figure 6-10 for details

Figure 6-8 – Combustion Turbine to Combined Cycle Conversion

Operating Characteristics and Estimated Costs	SCGT to 2x1 F Class CCGT Conversion
Base Load Net Output (MW)	717 / 257 incremental
Base Load Net Heat Rate (HHV Btu/kWh)	6,480
Base Project Costs (2022$/kW)	$774
Fixed O&M Costs (2022$/kW-year)	$5.86

Figure 6-9 – F.B. Culley 3 Natural Gas Conversion

Operating Characteristics and Estimated Costs	F. B. Culley 3 Gas Conversion
Base Load Net Output (MW)	270 / 0 incremental
Base Load Net Heat Rate (HHV Btu/kWh)	10,544
Base Project Costs (2022$/kW)[48]	$196
Fixed O&M Costs ($/kW-year)[49]	$39.16

Figure 6-10 – Cogeneration Technologies

Operating Characteristics and Estimated Costs	Cogeneration
Base Load Net Output (MW)	22
Base Project Costs (2022$/kW)	$2,832
Fixed O&M Costs (2022$/kW-year)	$323

6.3.1.2.1 Simple Cycle Gas Turbines (Combustion Turbines or CT)

SCGT 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 6-11 for further details on the simple cycle gas turbine technologies evaluated.

[48] Base project costs were evaluated in the earliest conversion year and discounted to 2022
[49] Fixed O&M costs were evaluated in the year following the conversion of the power plant

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. Estimates were developed for firm gas supply (as opposed to interruptible) because of recent changes to MISO's resource adequacy construct; they have signaled that while summer peak hours are important, all hours of the year matter and a dispatchable resource needs to be available for service when needed by the system. CEI South had two recent data points for what firm gas pipeline service could cost that were used to approximate what gas supply for various non-site specific gas resources could be based on their peak gas demand.

Figure 6-11 – Simple Cycle Gas Turbine Technologies

Operating Characteristics and Estimated Costs	1xF-Class SCGT	1xG/H-Class SCGT	1xJ-Class SCGT
Base Load Net Output (MW)	229	287	372
Base Load Net Heat Rate (HHV Btu/kWh)	10,010	9,260	9,240
Base Project Costs (2022$/kW)	$940	$910	$740
Fixed O&M Costs (2022$/kW-year)[50]	$8.30	$6.63	$5.11

6.3.1.2.2 Combined Cycle Gas Turbines

Combined Cycle Gas Turbines ("CCGT") 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 Heat Recovery Steam Generator ("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, a 1x1 F class (unfired and fired), 1x1 G/H class (unfired and fired), 1x1 J class (unfired), and 2x1 J class as shown in Figures 6-12 and 6-13, were evaluated with General Electric ("GE") turbines as representative CCGT technologies. The F class

[50] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs in this table

is based on the GE 7F.05 turbine and the G/H class is based on the GE HA.01 turbine. 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.

Figure 6-12 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines - Fired			
Operating Characteristics and Estimated Costs[51]	**1x1 F-Class**	**1x1 G/H-Class**	**2x1 J-Class**
Base Load (24/7 Power) Net Output (MW)	360	427	1,101
Incremental Duct-Fired (Peaking) Net Output (MW)	58	80	205
Base Load Net Heat Rate (HHV Btu/kWh)	6,590	6,240	6,280
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,730	8,720	8,690
Base Project Costs (2022$/Fired kW)	$1,300	$1,180	$770
Fixed O&M Costs (2022$/Base Load kW-year)[52]	$10.75	$8.85	$3.98

Figure 6-13 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines - Unfired			
Operating Characteristics and Estimated Costs[53]	**1x1 F-Class**	**1x1 G/H-Class**	**1x1 J-Class**
Base Load (24/7 Power) Net Output (MW)	363	431	551
Base Load Net Heat Rate (HHV Btu/kWh)	6,540	6,200	6,270
Base Project Costs (2022$/Fired kW)	$1,450	$1,320	$1,100
Fixed O&M Costs (2022$/Base Load kW-year)	$12.39	$10.45	$8.16

6.3.1.3 Renewables Technologies

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, and hydroelectric. Wind and solar resources were modeled to include production tax credits, while hydroelectric resources and storage included discounts for the investment tax credit. Under the IRA solar resources now have the option to choose between the investment tax credit and the production tax credit. Based

[51] Combined cycle gas turbines are shown as fired configuration for this table.
Reference the Technology Assessment for additional details on duct-firing
Operational and cost estimates developed by Black & Veatch
[52] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs in this table
[53] Combined cycle gas turbines are shown as unfired configuration for this table.

on the assumed capacity factor of solar resources, the production tax credits are anticipated to provide more value and therefore were used in the model.

6.3.1.3.1 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 6-14 for further details on wind technologies evaluated. Beyond the RFP bids, the following assumptions were based on the 1898 & Co. tech assessment.

Figure 6-14 – Wind Technologies

Operating Characteristics and Estimated Costs	Wind (Southern Indiana)	Wind (Northern Indiana)	50 MW Wind (Indiana) & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	200	200	50
Base Project Costs (2022$/kW) / ($/kWh for Storage)	$1,840	$1,840	$2,110
Fixed O&M Costs (2022$/kW-year)[54]	$48.00	$48.00	$49.00
Annual Capacity Factor	28%	38%	

6.3.1.3.2 Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a 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

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

aluminum back-plate on the other. See Figure 6-15 for further details on the solar PV technologies evaluated.

Figure 6-15 – Solar Technologies

Operating Characteristics and Estimated Costs	10 MW Solar PV	50 MW Solar PV	100 MW Solar PV	50 MW Solar PV & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	10	50	100	50
Base Project Costs (2022$/kW)	$2,560	$1,860	$1,780	$1,910
Fixed O&M Costs (2022$/kW-year)[55]	$60.00	$16.00	$11.00	$22.34

6.3.1.3.3 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 6-16 for further details on the hydroelectric technology evaluated.

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 when taking economics into consideration both dams 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.

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

Figure 6-16 – Hydroelectric

Operating Characteristics and Estimated Costs	John T. Myers	Newburgh
Base Load Net Output (MW)	36	22
Base Project Costs (2022$/kW)	$6,478	$6,478.29
Fixed O&M Costs (2022$/kW-year)	$98.90	$98.90

6.3.1.3.4 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered resources and are the most difficult to estimate. Congestion charges are calculated by taking the difference in Locational Marginal Price ("LMP") where the energy is injected (source) and where the energy is withdrawn (sink). For CEI South to purchase energy outside of Zone 6 (Indiana) or even off CEI South's system in Indiana, CEI South would be responsible to pay the LMP at the sink and would receive payment from the source. Therefore, any price differential is an added risk and possible added cost to the delivery of energy. MISO does not provide estimates of congestion charges due to the volatility and immense variability that impacts the MISO transmission system and the congestion related charges. When taking into consideration the cost of a resource, the required transmission charges and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

CEI South's modeling did not account for congestion. When selecting future resources following the resource plan, congestion and differences in LMP will be important factors to consider.

6.3.1.4 Energy Storage

Two types of energy storage technologies were evaluated in the IRP, lithium-ion batteries (typically short-duration) and compressed air storage (long-duration). These are shown in Figure 6-17.

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. However, the energy storage market is rapidly evolving. Long duration is not a defined term, but it is generally assumed that >4-hour discharge duration. Several non-lithium technologies may become competitive for long duration energy storage ("LDES") in the future. While it is technically achievable for multiple 4-hour lithium-ion battery systems to be controlled to behave similarly to a longer duration technology, the unit cost ($/kWh) for lithium-ion remains relatively flat for longer duration applications. In other words, there is not much economies of scale for longer duration applications. For this IRP we modeled 4-hour lithium-ion batteries but did not limit the number of resources selected, therefore, multiple 4-hour could be selected if a need for longer durations was identified by the model.

There are numerous technologies of varying commercial and technical maturity, and while CEI South recognizes the desire for technology diversity, a single representative technology was selected to represent the broader category of 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. CEI South is aware of other technologies/chemistries that are being marketed for durations >24 hours with cost targets that are lower than CAES and other LDES options, but CAES is generally considered as a more commercially and technically mature technology for this planning cycle. One technology that was not included in modeling but was considered by CEI South and mentioned by stakeholders was an iron-air battery by Form Energy. This was ultimately not modeled in this IRP because of the lack of commercial viability and lack of available modeling data at this time. CEI South will continue to evaluate emerging technologies and may include other technology(ies) in future resource planning cycles.

Figure 6-17 – Energy Storage Technologies

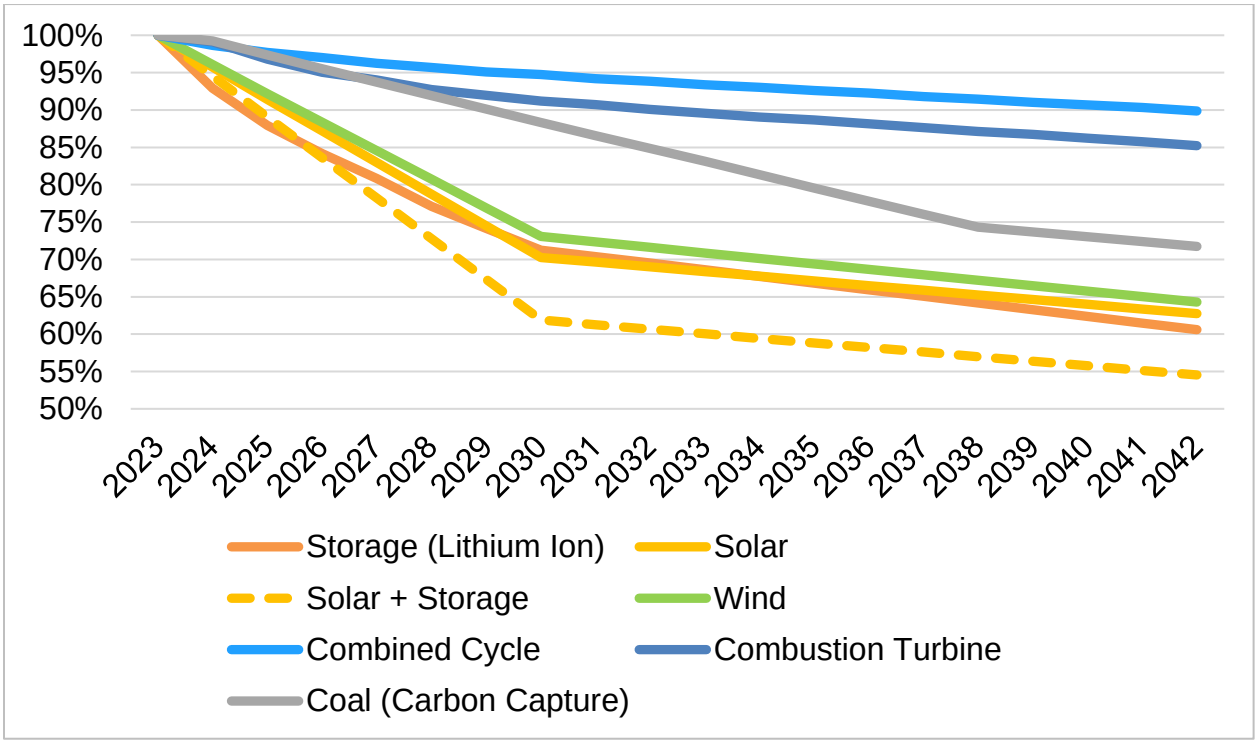
Operating Characteristics and Estimated Costs	Lithium Ion 10 MW / 40 MWh	Lithium Ion 50 MW / 200 MWh	Long-Duration Proxy 100 MW / 400 MWh	Long-Duration Proxy 300 MW / 3,000 MWh
Base Load Net Output (MW)	10	50	100	300
Round-Trip Cycle Efficiency	85%	85%	85%	60%
Base Project Costs (2022$/kW)	$2,500	$2,160	$2,020	$2,590
Fixed O&M Costs (2022$/kW-year)	$40.00	$38.00	$35.00	$19.33
Variable O&M Costs (2022$/MWh)	Included in FOM	Included in FOM	Included in FOM	$2.60

6.3.1.5 Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2022/2023 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 6-18.

Technologies whose capital costs do not decline significantly over the IRP time period such as wind, natural gas, coal and hydro are generally more mature, while technologies such as solar and storage are less mature and are expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies in solar and 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 RFP as well as NREL cost curves to help project capital costs over the study period. Figures 6-18 shows modeled values in the Reference case Scenario.

Figure 6-18 – Forward Capital Cost Estimates[56]



6.3.2 DSM

6.3.2.1 Energy Efficiency Background

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:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

[56] Percent decline based on real 2022 dollars.

In addition, this process aligns with Senate Enrolled Act ("SEA") 412 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.

6.3.2.2 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."[57] 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 ratepayers, the program administrator, program participants and utility rates.

[57] "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

CEI South's MPS completed in 2022 was both to inform the IRP and support the development of a DSM Action Plan for CEI South. The study included a comprehensive review of current programs, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study leveraged existing primary market research from the 2019 MPS for the C&I sector 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. Existing primary market research from the 2019 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 11% 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 BYOT programs, as well as potential new programs, such as 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.

6.3.2.3 Energy Efficiency – IRP Reference Case

Energy Efficiency for the 2023 and 2024 IRP years were informed directly from CEI South DSM Settlement Agreement (2023) and anticipated one-year plan extension (2024).

These years of energy efficiency were treated as a “going-in” resource in the IRP. For the remaining IRP years (2025-2042), 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 2023/2024 EE levels, the 2025-2042 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: 2025-2027, 2028-2030, and 2031-2042 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 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 average system line loss rate of 6% to convert savings from the meter level up to the generator level. Figure 6-19 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.

6.3.2.4 Demand Response ("DR")

Five bundles for DR savings were included for selection in the IRP Reference Case. The first bundle was included as a fixed adjustment to the total system load, similar to a "must-run" generation unit. This bundle includes DR savings associated with CEI South's current DR capabilities including the historical number of direct load control switches on residential air conditioning units in the CEI South service area. Over the IRP time frame, CEI South anticipates replacing existing direct load control switches with smart thermostats that integrate DR capabilities (via the Smart Cycle Program). The estimated annual impacts for the fixed bundle of DR are approximately 6.8 MW in 2025, increasing to 9 MW by 2042.

A second bundle, consisting of additional residential DR-enabled smart thermostats ("BYOT Thermostats") above and beyond the current penetration of DR devices, was included as a selectable resource. This bundle represents an additional 7.6 MW of peak reduction capabilities in 2025 increasing to 33 MW by 2042.

A third bundle consists of residential rate options, including critical peak pricing, peak time rebates, and time of use rates. This bundle is assumed to not start until 2026 and builds

slowly as a pilot program through 2030. In 2026, this bundle represents 0.3 MW in 2026 and increases to 18.5 MW in 2042.

A fourth bundle consists of additional C&I DR BYOT Thermostats above and beyond the current penetration of DR devices, which was included as a selectable resource. This bundle represents an additional 1.1 MW of peak reduction capabilities in 2025 and increases to 4.9 MW in 2042.

The fifth bundle consists of a critical peak pricing rate option for non-residential customers. This bundle is assumed to not start until 2026 and builds slowly as a pilot program through 2030. In 2026, this bundle represents 0.1 MW in 2026 and increases to 5.9 MW in 2042.

6.3.2.5 DSM Resources Optimization Process

The previous sections provided the Reference Case projection of DSM resource costs. DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20-year implementation period, alternate views of the costs should be examined in the context of the scenario analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections. To that end CEI South made specific targeted adjustments to identify the amount of EE selected at various cost and savings tiers as described below.

Figure 6-19 – 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	44,452	43,316	51,714	49,569	277,358	263,215
C&I	69,839	64,560	81,164	75,993	340,197	324,440
IQW	1,276	1,353	1,460	1,547	7,883	8,356

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. In addition, residential behavioral energy efficiency savings were also segmented into a third residential sector bundle due to its distinct 1-year measure life. Figure 6-20 summarizes the levelized cost per lifetime kWh saved of each initial bundle by vintage.

Figure 6-20 – Levelized Utility Cost per Lifetime MWh Saved Based on Initial Bundles

	Res Tier 1	Res Tier 2	Res Behavior	IQW	C&I
V1: 2025-2027	$50.99 - $51.95	$126.36 - $128.50	$35.18 - $37.35	$195.40 - $200.32	$21.07-$21.86
V2: 2028-2030	$52.51 - $53.52	$129.75 - $132.09	$38.51 - $41.01	$201.98 - $204.57	$22.70-$24.24
V3: 2031-2042	$52.41 - $65.64	$133.04 - $141.75	$42.37 - $60.12	$206.39 - $223.49	$25.22-$32.89

As part of an iterative review process, two further modifications to the sector level EE bundles were ultimately made. The first adjustment, which increased the overall savings and costs for commercial/industrial energy efficiency, were made at the request of members of the CEI South Oversight Board ("OSB")[58]. The GDS Team created an additional "Enhanced" Achievable Potential Scenario that increased incentives for select lower-cost commercial/industrial measures, resulting in increased estimates of measure adoption. This adjustment was requested due to the overall favorable levelized cost per lifetime kWh saved associated with the commercial/industrial sector, and the idea that additional savings could be realized without risking selection in the IRP model. In total C&I savings increased by 7.8% from 2025-2027, 4.5% from 2028-2030, and 1.5% from 2031-2042.

Conversely, based on a preliminary IRP model run, neither the Tier 2 nor Tier 1 residential sector bundles were selected in the IRP. To allow the IRP model to select residential energy efficiency, the residential sector bundles were redrawn, shifting higher cost measures in the original Tier 1 bundle into the Tier 2 bundle. This iterative re-screening of the Tier 1 and Tier 2 residential bundles in the IRP model ensured that a significant

[58] Citizens Action Coalition, Office of Utility Consumer Counselor, CEI South

component of the residential sector achievable potential would get economically selected in the IRP.

Figure 6-21 – Comparison of Preliminary and Final Tier 1 Savings and Costs

	Preliminary Vintage 1	Final Vintage 1	Preliminary Vintage 2	Final Vintage 2	Preliminary Vintage 3	Final Vintage 3
MWh	16,004	14,139	19,542	16,759	120,948	99,828
Costs	$6,898,272	$5,750,337	$8,372,620	$6,587,076	$52,278,442	$36,943,528

The final bundle incremental savings for energy efficiency and associated levelized utility cost per lifetime savings are provided in Figure 6-22 below. 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 End-Use Load Profiles database. The ultimate 8,760 shapes are unique for each EE sector and vintage bundle.

Figure 6-22 – Annual MWh EE Savings and Levelized Costs per Lifetime kWh Saved by Bundle

	Enhanced C&I		Res Tier 1		Res Tier 2		Res Behavior		IQW	
	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh
2025	21,523	$26.07	3,884	$48.54	1,592	$110.66	7,608	$35.18	442	$195.40
2026	23,569	$25.89	5,024	$48.63	2,286	$112.59	7,558	$36.24	439	$199.53
2027	24,508	$25.98	5,230	$48.93	2,629	$113.96	7,505	$37.35	471	$200.32
2028	25,885	$26.46	5,416	$49.24	3,003	$115.47	7,450	$38.51	492	$201.98
2029	26,035	$26.84	5,570	$49.31	3,448	$116.95	7,391	$39.72	523	$203.12
2030	27,470	$27.40	5,773	$49.21	4,191	$118.40	7,328	$41.01	533	$204.57
2031	28,769	$28.05	6,135	$49.38	4,867	$119.39	7,260	$42.37	549	$206.39
2032	29,196	$28.50	6,292	$49.46	5,515	$120.07	7,190	$43.80	560	$208.68
2033	29,006	$29.00	6,618	$49.68	6,060	$120.56	7,119	$45.28	578	$210.99
2034	29,105	$29.69	6,852	$49.95	6,447	$120.81	7,048	$46.81	595	$213.42
2035	29,115	$31.01	8,489	$51.69	7,064	$122.07	6,975	$48.42	629	$213.42
2036	27,731	$31.89	8,775	$52.51	7,226	$122.64	6,907	$50.05	659	$214.88
2037	26,828	$33.44	8,945	$53.41	7,112	$122.81	6,840	$51.73	696	$217.46
2038	25,458	$34.31	8,978	$54.44	7,006	$122.58	6,781	$53.41	733	$20.28
2039	23,775	$35.14	8,666	$55.31	6,794	$122.83	6,729	$55.08	777	$223.49
2040	27,805	$34.19	10,331	$57.74	7,502	$125.20	6,682	$56.77	819	$219.17
2041	26,718	$34.52	10,076	$58.47	7,543	$126.17	6,642	$58.45	862	$218.27
2042	25,916	$34.89	9,672	$59.26	7,468	$127.16	6,608	$60.12	899	$219.10

No IRP sensitivities for the low-income savings or DR savings were included in the IRP as these bundles were modeled as fixed load impacts.

6.3.2.6 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 2019 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 2025 and 2028 and then evaluates the remaining years beginning in 2031 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 bundles included in the IRP modeling was based on a collaborative process with the stakeholders. This led to originally separating bundles between the residential and non-residential sectors (aligning with recommendations from the prior IRP Directors Report), further breaking down the residential sector into the four bundles (including Income-Qualified) noted above, and finally increasing the C&I bundle savings and re-mapping the residential measure bundles to ensure cost-effective energy efficiency savings were selected 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, expanded DR bundles were included in the model.

6.3.2.7 Other Innovative Rate Design

CEI South periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives are being considered now that the required technology upgrades are being finalized, including technology to improve access to multitudes of data provided by installation of AMI.

CEI South formed a team of people to explore opportunities to provide customers with TOU rates. CEI South has hired Cadmus to help in researching and developing a pilot for a Critical Peak Pricing (“CPP”) program. CEI South plans to bring the proposal to the

Commission as part of its upcoming rate case and utilize results to help shape future resource planning.

6.4 TRANSMISSION CONSIDERATIONS

6.4.1 Description of Existing Transmission System

CEI South's transmission system is comprised of 64 miles of 345 kV lines, 430 miles of 138 kV lines and 570 miles of 69 kV lines. It 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.

6.4.2 Discussion on Resources Outside of Area

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 645 MWs in peak demand periods and approximately 750 MWs in off-peak demand periods (or approximately 35-40% of peak demand). 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

6.4.3 Transmission Facilities as a Resource

As part of this year's IRP, CEI South performed a multitude of transmission planning analyses to study a wide range of potential futures. These included studying the additional retirement of coal generation and partial replacement of these retirements with Battery Energy Storage Solutions ("BESS"), Conversion of FB Culley to natural gas, and import from the MISO market. Each of these cases also included the addition of various levels of renewable resources, primarily solar. The models utilized were from the latest 2022 MISO Transmission Expansion Plan ("MTEP") model series, which includes future transmission system projects and approved generation interconnections. The primary focus of the analysis was on the peak and off-peak (Shoulder) 5-year planning horizon. 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 projects in final negotiations to execute generation interconnection agreements with MISO. These projects were included in order to have the latest modeling data for generation resources in CEI South's area. The renewable resources used for CEI South's analysis were projects already in the MISO queue and existing in the MISO models. The analysis did account for the new CTs at CEI South's A.B. Brown power plant.

The convert F.B. Culley 3 to natural gas case was modeled at a similar MW output as the coal generation it was replacing and therefore the results of the transmission planning study analysis showed very few differences from the study case with the system as it is today, or Base Case. Therefore, no costs were identified in this case to mitigate potential issues on the system.

The analysis found the need for facility upgrades and voltage support under scenarios with retirement of FB Culley Unit 3 and integration of renewable resources. The total estimated costs of system reinforcements identified ranged from $17.6 million to $328

million depending on the scenario evaluated. The scenario where Culley Unit 3 is retired included mitigation costs of $17.6 million under the peak demand period. The F.B. Culley replacement with BESS had mitigation costs between approximately $154 million and $328 million. The magnitude of system reinforcements was the most significant during the off-peak demand period, as opposed to the peak demand period, driven by heavy imports, no solar production, and BESS charging conditions. Major upgrades on the high-end include rebuilding several transmission lines on the 138 kV system, two (2) additional 345/138 kV transformers at A.B. Brown, an upgrade of the A.B. Brown to Gibson 345 kV line, and an additional 560 MVar of reactive support. The system reinforcements would reduce further as the size of the BESS is reduced.

The system reinforcement needs under the peak demand period for the heavy import scenario were estimated to be between $17.5 million and $55 million. The magnitude of system reinforcements was found to be more in a heavy import scenario. Major upgrades on the high-end include two (2) additional 345/138 kV transformers at A.B. Brown and an additional 229 MVar of reactive support.

6.5 Partnering with Other Utilities

2022/2023 CEI South remains committed to partnering with other Indiana electric utilities where doing so provides the opportunity to more cost effectively construct generation. CEI South issued a broad request for proposals as part of this IRP process. While other Indiana electric utilities could have submitted bids, none were received. Many of the projects CEI South is pursuing are being constructed by developers, some of whom are developing projects for other Indiana electric utilities already. Some of the projects submitted in response to the RFP could likely be split between CEI South and other electric utilities. Other projects being pursued by CEI South, such as converting Culley Unit 3 to gas, are not of sufficient size or scope to warrant partnership with other Indiana utilities. CEI South remains abreast of other Indiana electric utilities' IRPs and will dialogue with them, as appropriate, around appropriate partnership opportunities. CEI

South maintains strong relationships with the other Indiana investor-owned utilities and will utilize these resources to explore appropriate partnerships.

SECTION 7
MODEL INPUTS AND ASSUMPTIONS

7.1 RESOURCE MODEL (EnCompass)

EnCompass was the primary tool for conducting CEI South's analysis. EnCompass is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a mixed integer programming approach ("MIP") to determine the optimal solution to capacity expansion, unit commitment, and economic dispatch problems, while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets.

The model can be run in several modes; two were utilized for this study. The Capacity Expansion mode was utilized to determine the least cost mix of existing and new generating assets that meets demand (electric load) over time and meets regulatory and reliability requirements. Then a detailed economic dispatch mode, where the portfolios that were made in the Capacity Expansion mode were run on a more granular level.

EnCompass is widely used by electric utilities, consulting agencies and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g., heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates, and capital costs. The model assesses the potential performance, fixed and variable O&M costs and capital costs of prospective and existing generation/DSM resources and makes resource addition and retirement decisions for economic, system reliability and policy compliance reasons on a utility system (regional and nationwide scale). Outputs of the model include plant generation, gross margin, emissions, power prices, capacity additions, retirements and a variety of other metrics.

The model is equipped to determine least cost portfolios, and it can analyze portfolio risks by assessing portfolio performance across different future market outlooks. 1898

developed a stochastic framework to ensure these future market outlooks reflect both relevant historic uncertainty in key market drivers and cross relationships between different market drivers. For this reason, it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. 1898 has successfully conducted numerous IRPs for many utilities across the country. EnCompass has gained wide acceptance among electric utility executives, stakeholder groups and regulatory commissions.

To perform both the required deterministic (scenario based) and probabilistic (stochastic) modeling, using scenario narratives created with stakeholder input, 1898 developed five scenarios and a set of probability distributions for key market driver variables. These include both forecasts of each variable under the five scenario conditions and probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), other variables were also varied in the risk analysis including environmental compliance costs (carbon) and capital costs. The sections below include a description of how these forecasts and distributions were developed.

7.2 REFERENCE CASE SCENARIO

CEI South developed a Reference Case forecast of key market drivers that collectively represent the expected or most likely future for each input variable. For key assumptions, including natural gas prices, coal prices and capacity prices, a range of views from various vendors were incorporated into a consensus forecast.

The Reference Case scenario is based upon consensus forecasts from several consultants. Hence, it is impossible to describe specifics regarding the assumptions driving each forecast. However, the Reference Case can be described in more general terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth, best guess forecasts of market conditions, regulatory

requirements and technological change. Typically, market participants under Reference Case conditions can adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2023-2024), the Reference Case assumes an overall positive sales growth. Residential customer annual consumption is expected to increase in the short term with this trend continuing in the medium-term and long-term. Commercial sales are expected to remain flat in the near term before declining slightly in the medium-term and long-term. Industrial sales are expected to increase significantly in the near term with the addition of a new large customer with slight growth expected in the long-term.

Natural gas prices are expected to continue declining in 2024 and 2025 compared to 2023, as U.S storage levels are expected to increase. In the short-term, the consensus forecasts show natural gas prices are expected to remain below $4.50/MMBtu. However, prices have dropped significantly since CEI South started the IRP in 2022 when Henry Hub prices spiked in the fall. The EIA's short term energy outlook shows 2023 prices below $3.00/MMBtu.

Meanwhile, coal prices decline in the near-term as domestic markets remain soft and the energy crisis in Europe eases. Exports of coal provide a small amount of upward pressure demand, but mine prices are expected to continue to decline in the short-term from the 2023 price of $3.87/MMBtu in the Illinois Coal Basin.

Coal plant retirements were high in 2015 driven by regulation including MATS and again in 2018 for economic reasons with retirements expected to continue as the fleet transition moves forward. Capacity additions fueled by natural gas are expected to continue to support the renewable resources that are planned to be added to the system. Data from the EIA AEO 2023 report anticipates a continued pace of capacity additions over the next few years with a significant buildout of renewable resources.[59]

[59] https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf , EIA Annual Energy Outlook, page 9, U.S. Energy Information Administration

The Reference Case reflects the assumption that a carbon policy will be implemented on the national level and used costs associated with complying with the ACE Rule as proxy. In this IRP, CEI South is accounting for both direct CO_2 emissions and CO_2-equivalent (CO_2e) emissions.

Medium Term: In the medium-term (2025-2031), as in the short-term, energy efficiency standards and energy company sponsored DSM programs mostly offset the growth in energy sales from a growing residential customer base. However, overall load growth continues, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas and through the adoption of EVs.

Natural gas prices at the Henry Hub in the medium-term are expected to remain relatively flat, with the consensus forecast anticipating prices in the $4.00-$4.90/MMBtu range. Natural gas markets prices have continued to decline in real time as CEI South performed its IRP analysis with the EIA Annual Energy Outlook predicting prices will continue to decline until 2028 where they bottom out near $2.80/MMBtu and only rise slightly the next few years ending near $3.00/MMBtu in 2031.

Coal prices in the Illinois Basin are expected to remain relatively flat in the medium-term, as the modest export market is unable to compensate for declining domestic demand. Consensus Illinois Basin prices at the mine have increased since the last IRP, averaging $2.98/MMBtu over the study period, with a steady increase over time.

Power prices, which were developed in EnCompass, decline along with natural gas prices over the first few years of the study period. This decline in prices levels out over the medium-term as a balance of more renewables continue integrating onto the grid and the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to improve and

the unemployment rate remains near historically low levels, capital costs rise as competitive upward pressure remains on labor costs.

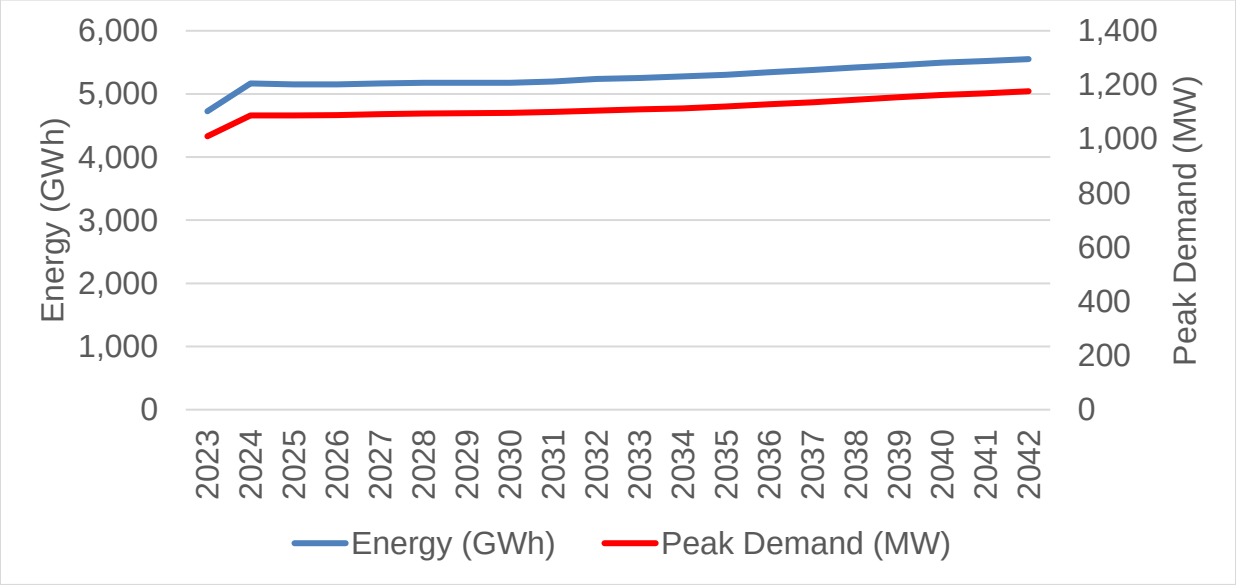
Long Term: In the long-term (2032-2042), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.7% CAGR for 2023-2042)[60]. The consensus forecast for Henry Hub has prices reaching $4.76/MMBtu by 2042 (in real 2023$), while ILB coal prices at the mine increase to $2.33/MMBtu by 2042 (in real 2023$). Energy demand grows as electric vehicle sales take hold and as residential and commercial customers electrify their energy use, but this is partially offset by continued gains in distributed solar generation, demand side management and energy efficiency measures. Domestic shale gas resources help to keep fuel cost growth to a relatively low level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more and as higher borrowing costs come from long-term rising interest rates. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

7.2.1 Input Forecasts

The long-term energy and demand forecast for the CEI South service territory was developed for CEI South by Itron. The long-term energy and demand forecast for the MISO market comes from the System Forecasting for Energy Planning section of MISO's website.[61] For more information, please see Section 4 Customer Energy Needs and Technical Appendix 4.1. The forecast is based on a combination of historical usage trends and a bottom-up approach to drivers such as residential and commercial demand, industrial load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, electric vehicle adoption and an outlook for economic factors.

[60] Does not include impact of company sponsored EE programs.
[61] https://www.misoenergy.org/planning/policy-studies/system-forecasting-for-energy-planning/#nt=%2Freport-study-analysistype%3ALoad%20Forecast&t=10&p=0&s=FileName&sd=desc

Figure 7.1 – Reference Case CEI South Load Forecast (MWh and MW)



For both natural gas and coal CEI South used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. For natural gas and coal, forecasts from Wood Mackenzie, ABB, S&P Global, & EVA were averaged. For capacity, CEI South used a consensus forecast, using ABB and S&P Global[62]. This helps to capture views from several experts and allows CEI South to be more transparent in the planning process. The consensus forecast for Henry Hub was adjusted based on historical price separation between Henry Hub and delivered gas prices to the CEI South system.

[62] CEI South did not have access to a capacity forecast from Wood Mackenzie or EVA

Figure 7.2 – Reference Case Natural Gas Price Forecast (2023$/MMBtu)

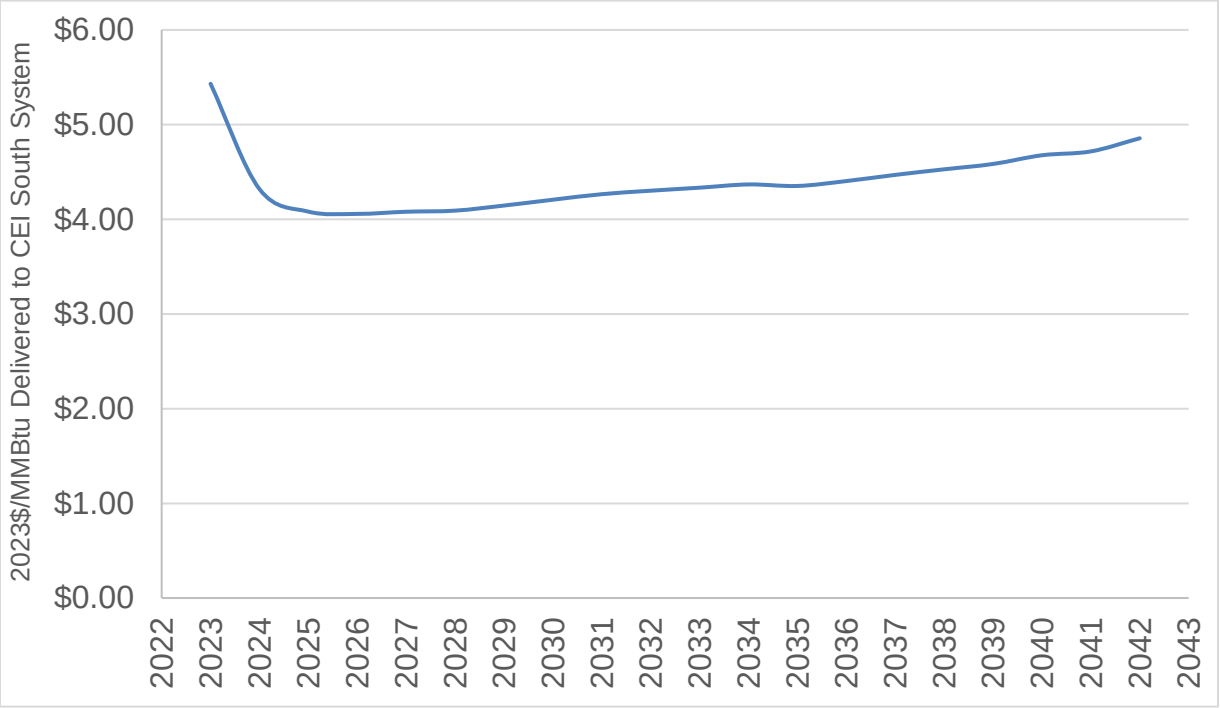
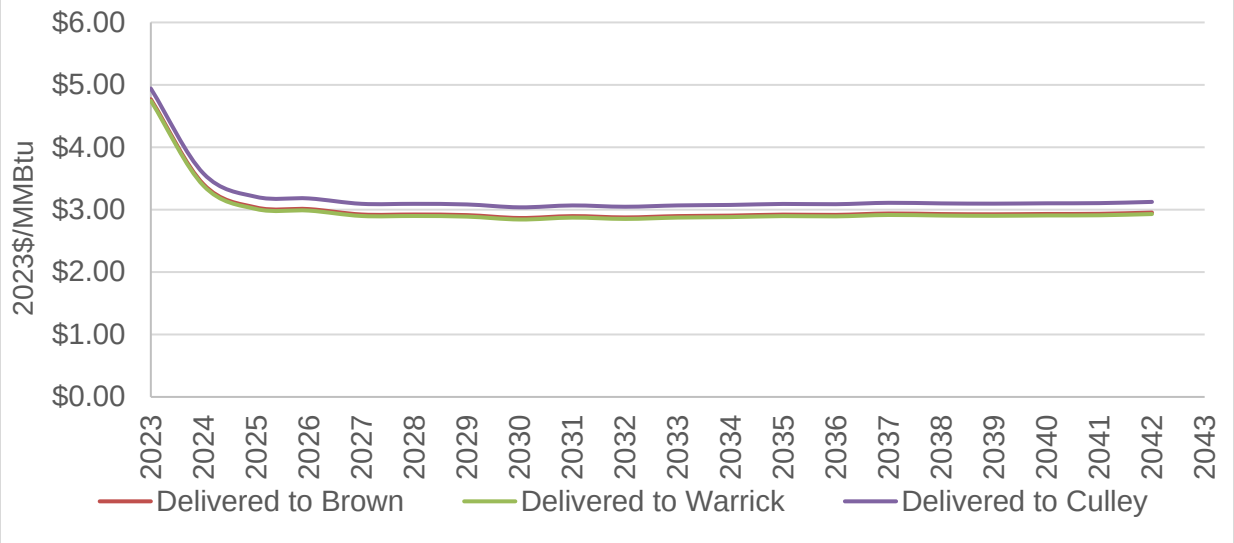


Figure 7.3 – Reference Case Coal Price Forecast (2023$/MMBtu)



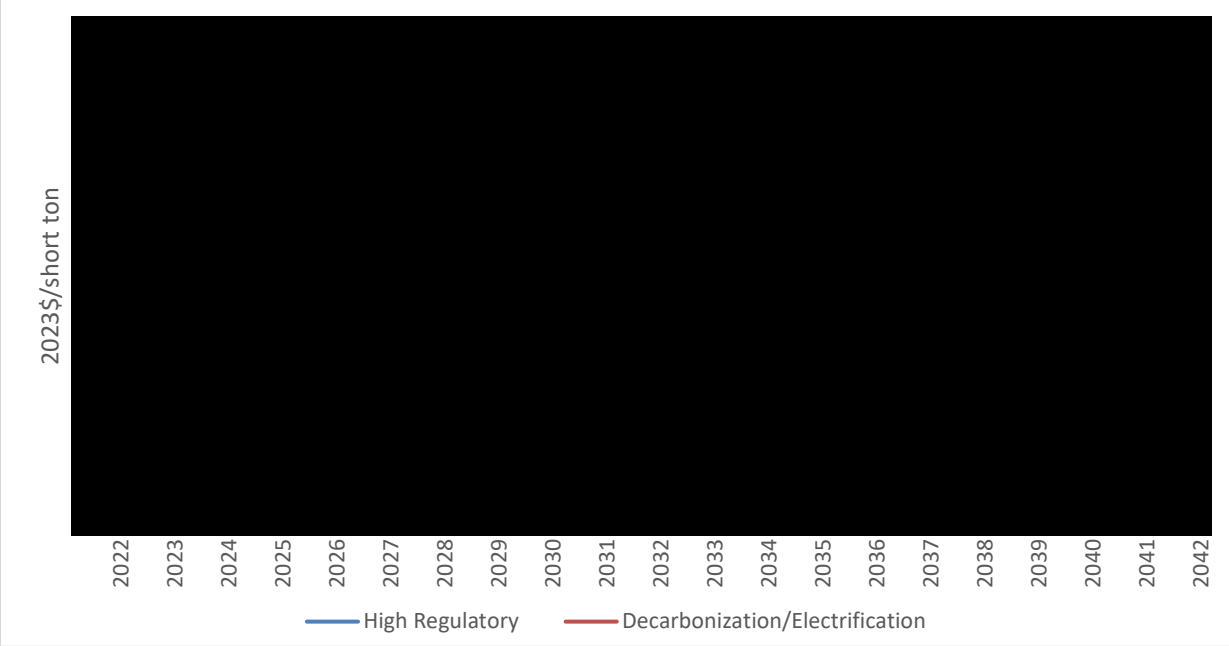
During this analysis, no comprehensive national legislation of carbon emissions existed in the United States. Efforts to enact federal policy covering carbon emissions from major

sources have occurred over the years. This included efforts by the U.S. Congress to pass a national cap-and trade regime, the EPA's regulation of GHG emissions from new and existing power generators which culminated in the ACE rule (which was modeled in this IRP as a proxy for future carbon costs), and more recently proposals in the U.S. Congress for carbon taxes and comprehensive clean energy targets.

Action to limit carbon emissions has increased in recent years with states taking the lead in defining low and no-carbon generation requirements. Indiana does not have a state policy limiting or otherwise placing a price on carbon emissions from power generation. However, the potential remains for enactment of such a policy at the national level over the study period. To account for this uncertainty, in the reference case the ACE rule was used as a proxy for carbon regulation for coal generators. Costs were included in the modeling to improve the efficiency of F.B. Culley 3 which would reduce their overall emissions. A carbon tax was assumed in the High Regulatory and Decarbonization/Electrification scenarios. In the High Regulatory scenario, a carbon tax starts in [redacted] per ton and increases over the planning period to [redacted] per ton. In the Decarbonization/Electrification scenario the tax starts in [redacted] per ton and increases over the planning period to [redacted] per ton.

On May 11, 2023 EPA released a pre-publication version of a new GHG proposal which seeks to establish new GHG emission reduction requirements for existing coal-fired EGUs and new and existing gas-fired EGUs. New regulatory language accompanying this proposal was released on May 15, 2023. Upon publication EPA will commence a notice and comment period and it is anticipated that the new proposal will receive a significant number of public comments from a wide range of stakeholders.

Figure 7.4 – Confidential High Regulatory and Decarbonization/Electrification Scenarios CO_2 Price Forecast (2023$/short ton)[63]



Capital costs in the near to midterm (through 2026) were based on bids received in the All-Source RFP, as described in Section 6.1.6 Grouping. As described in Section 6, non-renewable capital costs were developed by 1898 & Co. as well as long term solar, wind and battery storage costs. Long-term capital costs for storage, solar, and wind were adjusted to reflect bid pricing in the near term and then the NREL capital cost indexes were used to adjust prices beyond the bid period. Forward capital cost estimates can be found in Figure 6-18.

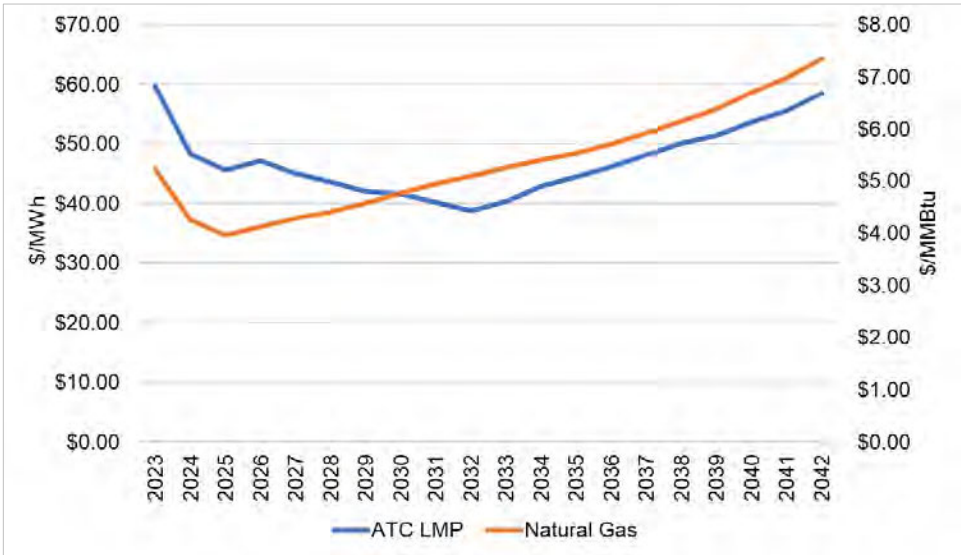
7.2.2 Energy Prices

Energy prices as an input into the IRP model were developed by 1898 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

[63] Proprietary forecasts from one vendor, ABB

("ATC") power price forecast can be seen below in Figure 7.5, which also illustrates the macro correlation to natural gas prices over the study period.

Figure 7.5 – Reference Case Power Price Forecast (Nominal $/MWh)



7.2.3 Environmental Regulations

The current modeling analysis includes relevant costs primarily focused on evaluation of alternatives to comply with the CCR, ELG, 316(b) and ACE rule proxy requirements where applicable. All 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.

7.2.3.1 Effluent Limitations Guidelines (ELG)

A. B. Brown: ELG related changes would need to include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash and a new system to handle process waters. Costs for these changes were not included in the study due to the retirement of Units 1 and 2 eliminating the need for these changes and associated expenditures.

F. B. Culley: Unit 3 is equipped with dry fly ash and dry bottom ash systems, thereby eliminating transport water discharges. The Spray Dryer Evaporator Zero Liquid Discharge system has been completed and is online, meeting the ELG requirements that are incorporated into the NPDES permit, eliminating the discharge of FGD Wastewater.

For Warrick Unit 4, CEI South modeled its share of the total capital spend.

7.2.3.2 Coal Combustion Residuals (CCR)

For A. B. Brown and F. B. Culley, it was assumed ash ponds would be closed at the end of their useful life. The timing of the closures is based on forced closure (i.e., exceedance of GWPS and failure of aquifer location restriction) and compliance with the Site-Specific Alternatives to Initiate Closure 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. CEI South has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by WPP4 and therefore is not liable for pond closure costs.

7.2.3.3 Affordable Clean Energy (ACE)

As described earlier, In June 2019 EPA finalized the ACE rule, which replaces the Clean Power Plan from 2015 (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels). This rule was vacated in January of 2019, but CEI South used ACE as a proxy for carbon legislation in the reference case. Since A.B. Brown 1 & 2 and F.B. Culley 2 are planned for retirement in 2023 and 2025 respectively no ACE costs were included for these units. Similarly, since CEI South plans to exit joint operations of Warrick 4 in 2023 no ACE costs were included for this unit.

Figure 7.6 – ACE Cost

Unit	Total ACE Upgrade Cost (2023$)
A.B. Brown 1	N/A
A.B. Brown 2	N/A
F.B. Culley 2	N/A
F.B. Culley 3	$34 Million
Warrick 4	N\A

7.2.3.4 316(b)

EPA issued its final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for Cooling Water Intake Structures ("CWIS") at existing facilities.

This requirement applies to both F. B. Culley and Warrick. At this time, based on available information for A. B. Brown, IDEM has made a Best Technology Available determination that the existing cooling water intake structures represent best technology available to minimize adverse environmental impact. This determination will be reassessed at the next NPDES permit reissuance. Standard fine mesh and fish friendly screens and fish return systems were estimated to be $21M at F. B. Culley. The F.B. Culley NPDES renewal permit was issued on February 1, 2023 with a March 1, 2023 effective date. IDEM made the determination that the Best Technology Available ("BTA") for both impingement and entrainment is 1.0 mm wedgewire screens, and the facility is required to submit additional information regarding site specific feasibility studies with respect to both determinations, after which IDEM will reevaluate these determinations. Warrick is required to install modified travelling screens and a fish handling and return system at Warrick. CEI South is not responsible for its share of total capital.

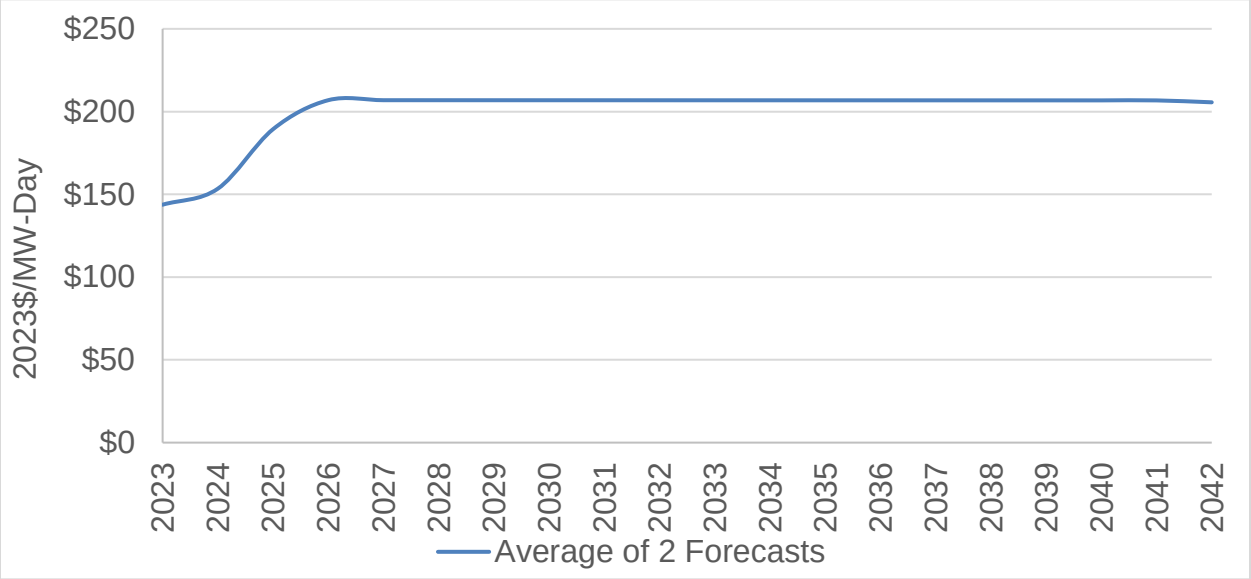
7.2.3.5 Market Capacity Price

The MISO capacity price has been difficult to predict as was shown by the results of the 2022-2023 MISO Planning Resource Auction. All of MISO's North\Central region cleared at Cost of New Entry ("CONE") because of a capacity shortfall. While the Planning Resource Auction did not clear at CONE ($270/MW-Day[64]) for the 2023/2024 planning year, this trend is expected to continue. To put this number in perspective, the annual capacity value of a resource that receives 100 MWs of accreditation at CONE is nearly $10 million. As MISO has transitioned to a seasonal construct the seasonal accreditation

[64] MISO annual CONE calculation –Page 9 - https://cdn.misoenergy.org/MISO%202022%20Annual%20CONE%20filing626484.pdf

for new wind and solar resources varies from 18%-40% and 5%-50%[65] respectively while a fossil steam resource similar in size to F.B. Culley would receive accreditation near ~90%. While some capacity will be bought or sold nearly every year since load, planning reserve margin requirements, and resource accreditation vary by season. Most new supply side resources, such as generating units, come in large blocks with 30+ year expected lifetimes. A portfolio that lacks adequate capacity resources introduces cost risk the CEI South customers. For modeling purposes, CEI South used a consensus forecast, utilizing ABB and S&P Global for Reference Case MISO Indiana capacity prices.

Figure 7.7 – Capacity Market Value Forecast (2023$/MW-Day)



7.2.4 Additional Modeling Considerations

CEI South received approval in 2022 from the Commission to replace A.B. Brown Units 1&2 with two natural gas combustion turbines. As such, the units were modeled in all portfolios throughout the planning period. Likewise, renewables projects for which CEI South has filed for a CPCN with the IURC since the last IRP have been included in all portfolios. These projects are described in Section 1.3.1 Generation. F.B. Culley coal unit

[65] Wind and solar class averages of PY 23-24 – MISO, 2023; https://cdn.misoenergy.org/Wind%20and%20Solar%20Class%20Average%20SAC627924.pdf

3 could retire economically within the model beginning December 31, 2029. This allows for enough time for replacement generation to be acquired. Note that a conversion of F.B. Culley 3 to natural gas may occur by 2027 due to the MISO interconnection transfer process and six month construction timeline.

Modeling also included other fixed considerations. All candidate portfolios were designed to include energy efficiency equivalent to 1.2% of sales, in the near-term years of 2025-2027. The process used to identify this level is described in section 6.3.2.5 DSM Resource Optimization Process.

As described in section 2.5, Recent legislation was passed in Indiana, capping the reliance on MISO's planning resource auction at 15%. This limit helps to ensure portfolios do not overly rely on capacity purchases in the long term. There is more certainty in the near term about what might be available through bi-lateral contracts. As such, early years included higher thresholds of 300 MWs through 2025 and 180 MWs 2026-2028.

The modeling is performed in 2 steps, the first of which is the capacity expansion step, where EnCompass determines the resource retirement and replacement decisions and timing. The second is a chronological hourly dispatch using the inherited portfolio for the entire study period. For portfolios to be built, the model did not rely on capacity sales into the market, during the capacity expansion step. Then during the detailed dispatch step, excess capacity was allowed to be sold once the portfolio was locked down.

7.3 ALTERNATE SCENARIOS

To develop several alternative scenarios for its IRP process, CEI South used a construct that allowed various regulatory and market conditions across four alternative scenarios. As previously mentioned, there were two purposes for these scenarios. First, each alternative market scenario was used to develop a least cost portfolio. Second, the final list of portfolios was evaluated against each alternative market scenario.

The alternate scenarios, created with stakeholder input, included the High Regulatory scenario, the Market Driven Innovation scenario, the Decarbonization/Electrification scenario and the Continued High Inflation & Supply Chain Issues scenario. 1898 & Co. provided the qualitative descriptions and quantitative inputs for each of these scenarios, which were based on collaboration between CEI South, 1898 & Co. and stakeholders.

7.3.1 Description of Alternate Scenarios

As described in Section 2.4, the second purpose of developing these "boundary" scenarios was to test a relevant range for each of the key market drivers (gas, coal, CO_2, load and capital costs) on how various technologies perform under boundary conditions.

7.3.1.1 High Regulatory

The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee is implemented throughout the planning horizon (2023 - 2042). A fracking ban is imposed, driving up the cost of natural gas notably in the long-term as supply dramatically shrinks. Declining demand for coal is offset by regulations that increase the coal price resulting in coal prices higher than to the Reference Case as coal mines close and remaining coal producers can charge more per ton, passing costs of new regulations on to remaining customers. Although technological innovation is stifled, renewables and battery storage receive government incentives, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

7.3.1.2 Market Driven Innovation

The Market Driven Innovation scenario includes transition to a more free market leads to new and advanced technology, driving down energy prices. Less government influence drives competition among competing fuels and no carbon tax results in lower power prices from natural gas and coal resources. Increased energy usage is a direct result of less government influence reducing overall costs. Further technological innovation to lower

energy cost is spurred by an increase in demand for renewable and storage resource options. This advancement in technological innovation drives more opportunities for energy efficiency programs. Energy efficiency programs are predicted to be more cost effective with increased load. In addition, less codes and standards changes allow utility sponsored energy efficiency programs to transform the market at a lower incentive cost.

7.3.1.3 Decarbonization/Electrification

The Decarbonization/Electrification scenario assumes that utility-sponsored energy efficiency costs are below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy. As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes and other buildings. The switch to electrification causes an increase in load and natural gas supply; however, the natural gas prices remain at Reference Case level due to methane regulations. A mid-level carbon tax is imposed causing demand for coal to decrease and supply constraints cause coal prices to increase. Technological improvements to lower costs are offset by higher demand and rising land and labor costs.

7.3.1.4 Continued High Inflation and Supply Chain Issues

The Continued High Inflation and Supply Issues scenario assumes a shortage in labor and materials, costs for new technologies and fuels are increasing. Higher labor and delivery costs reduced the supply of fuel leading to higher coal and natural gas prices. Load demand is negatively affected by high inflation causing reduced economic output. Like the Reference Case, no carbon price is imposed. Continued disruptions in the supply chain along with high inflation leads to higher costs for renewables and storage. Reduction in load results in less potential of energy efficiency acquisition both for incentives passed to customers and implementation of programs as implementers experience increased cost. In addition, shortage of EE equipment leads to increased cost of high-efficient measures.

7.3.2 Coordinated Forecasts for Alternate Scenarios

The qualitative description of alternate scenarios described in Section 7.3.1 were next translated into quantitative inputs for use as modeling inputs. The steps in this process were described in Section 2.

- Probability distributions were developed for each input variable.
- A table was developed that determined whether the variable would be above or below the Reference Case in the short, mid and long term.
- Values in specific years were developed by moving up or down one standard deviation (for gas sometimes two standard deviations) from the mean or reference forecast.
- Smoothing occurred to reach interim year values.

This was done using a probabilistic modeling framework, described below, which allowed the development of higher and lower forecasts, relative to the Reference Case for monthly natural gas prices, CO_2 prices, coal prices, peak load for CEI South as well as surrounding markets (MISO, PJM and SERC) and capital costs for renewables and storage technologies.

7.3.2.1 Probability Distributions

To perform the stochastic analysis that develops 200 sets input variables, probability distributions that describe uncertainty were developed for the key market driver variables discussed above (natural gas prices, coal prices, CO_2 prices, peak load and renewables capital costs). These probability distributions were developed by defining the uncertainty around each of the variables on a monthly basis. Lognormal probability distributions were assigned for natural gas prices, coal prices and peak load. Discreet probability distributions were defined for CO_2 prices and renewables capital costs. Once probability distributions around each of the inputs were defined, the lognormal probability distributions were inputted into EnCompass. Using EnCompass' stochastic modeling, 200 iterations were run for natural gas pricing, coal pricing and peak load to form 200 sets of inputs. Probability distributions for CO_2 prices and for renewables capital costs were then

assigned to the 200 sets of inputs to develop 200 complete sets of inputs. The methodologies for developing the probability distributions used in the stochastics process are Described in the Technical Appendix 11.6.

7.3.2.2 Model Inputs

The following graphs illustrate the key market driver inputs across all the alternate scenarios.

Figure 7.8 – CEI South Peak Load (MW) Alternate Scenarios

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	1,010	996	1,017	1,017	996
2023	1,010	996	1,017	1,017	996
2024	1,087	1,068	1,097	1,097	1,068
2025	1,087	1,066	1,098	1,098	1,066
2026	1,088	1,064	1,101	1,101	1,064
2027	1,092	1,065	1,105	1,105	1,065
2028	1,095	1,065	1,110	1,110	1,065
2029	1,095	1,062	1,112	1,112	1,062
2030	1,096	1,059	1,115	1,115	1,059
2031	1,100	1,061	1,120	1,120	1,061
2032	1,105	1,060	1,128	1,128	1,060
2033	1,110	1,059	1,135	1,135	1,059
2034	1,114	1,059	1,142	1,142	1,059
2035	1,120	1,060	1,150	1,150	1,060
2036	1,128	1,061	1,162	1,162	1,061
2037	1,136	1,063	1,174	1,174	1,063
2038	1,145	1,067	1,185	1,185	1,067
2039	1,154	1,071	1,197	1,197	1,071
2040	1,162	1,071	1,209	1,209	1,071
2041	1,169	1,070	1,220	1,220	1,070
2042	1,177	1,072	1,231	1,231	1,072

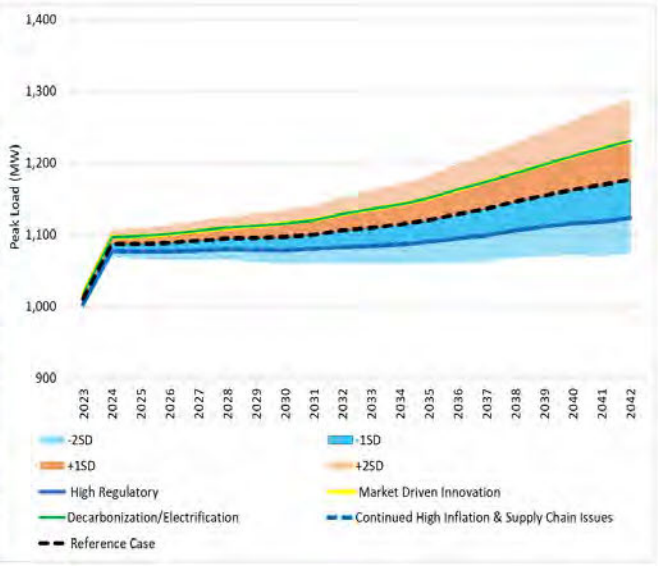


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$2.89	$2.89	$2.89	$2.89	$2.89
2023	$4.39	$4.39	$4.39	$4.39	$4.39
2024	$3.09	$3.09	$3.09	$3.09	$3.09
2025	$2.77	$3.13	$2.77	$3.13	$3.13
2026	$2.81	$3.16	$2.62	$3.16	$3.16
2027	$2.78	$3.19	$2.46	$3.19	$3.19
2028	$2.85	$3.22	$2.47	$3.22	$3.22
2029	$2.90	$3.31	$2.49	$3.31	$3.31
2030	$2.91	$3.34	$2.48	$3.34	$3.34
2031	$3.02	$3.48	$2.55	$3.48	$3.48
2032	$3.06	$3.52	$2.60	$3.52	$3.52
2033	$3.16	$3.67	$2.64	$3.67	$3.67
2034	$3.24	$3.77	$2.71	$3.77	$3.77
2035	$3.33	$3.88	$2.79	$3.88	$3.88
2036	$3.41	$4.00	$2.81	$4.00	$4.00
2037	$3.51	$4.12	$2.91	$4.12	$4.12
2038	$3.58	$4.22	$2.94	$4.22	$4.22
2039	$3.66	$4.34	$2.97	$4.34	$4.34
2040	$3.75	$4.45	$3.05	$4.45	$4.45
2041	$3.84	$4.58	$3.10	$4.58	$4.58
2042	$3.96	$4.71	$3.21	$4.71	$4.71

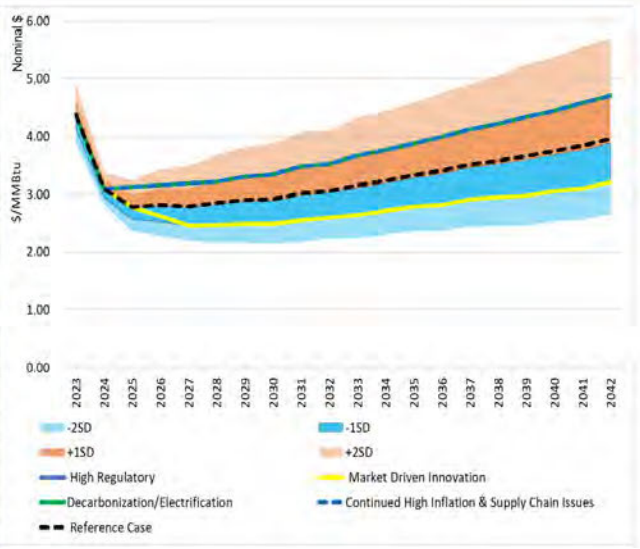


Figure 7.10 – Natural Gas (Henry Hub) Alternate Scenarios ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$5.82	$5.82	$5.82	$5.82	$5.82
2023	$5.68	$5.68	$5.68	$5.68	$5.68
2024	$4.65	$4.65	$4.65	$4.65	$4.65
2025	$4.43	$5.64	$4.29	$4.43	$5.04
2026	$4.50	$6.63	$3.93	$4.50	$5.42
2027	$4.57	$7.62	$3.57	$4.57	$5.80
2028	$4.70	$8.61	$3.21	$4.70	$6.19
2029	$4.87	$8.85	$3.34	$4.87	$6.39
2030	$5.05	$9.44	$3.38	$5.05	$6.70
2031	$5.23	$10.00	$3.44	$5.23	$7.01
2032	$5.39	$10.51	$3.49	$5.39	$7.28
2033	$5.55	$11.01	$3.55	$5.55	$7.55
2034	$5.72	$11.47	$3.62	$5.72	$7.81
2035	$5.83	$11.55	$3.73	$5.83	$7.92
2036	$6.03	$11.68	$3.93	$6.03	$8.12
2037	$6.26	$12.09	$4.08	$6.26	$8.42
2038	$6.48	$12.42	$4.26	$6.48	$8.69
2039	$6.71	$12.64	$4.47	$6.71	$8.94
2040	$7.00	$13.19	$4.66	$7.00	$9.32
2041	$7.22	$13.58	$4.81	$7.22	$9.60
2042	$7.59	$14.31	$5.06	$7.59	$10.11

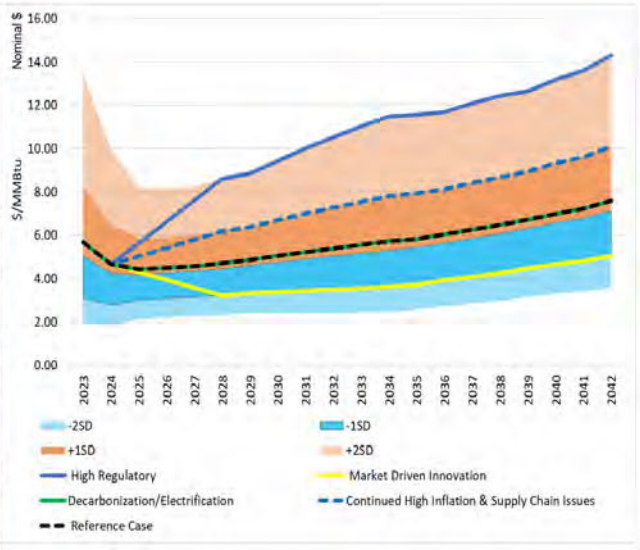


Figure 7.11 – Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)[66]

Year	Reference Case	Low	High	NREL
2022	$1,943	$1,700	$2,057	$1,172
2023	$1,943	$1,700	$2,057	$1,149
2024	$1,943	$1,700	$2,057	$1,125
2025	$1,943	$1,700	$2,057	$1,100
2026	$1,943	$1,700	$2,057	$1,073
2027	$1,891	$1,663	$2,104	$1,044
2028	$1,836	$1,626	$2,152	$1,014
2029	$1,777	$1,589	$2,201	$981
2030	$1,714	$1,552	$2,252	$946
2031	$1,737	$1,515	$2,303	$959
2032	$1,761	$1,478	$2,356	$973
2033	$1,785	$1,442	$2,410	$986
2034	$1,809	$1,405	$2,465	$999
2035	$1,834	$1,368	$2,522	$1,013
2036	$1,858	$1,331	$2,580	$1,026
2037	$1,883	$1,294	$2,639	$1,040
2038	$1,908	$1,257	$2,699	$1,054
2039	$1,933	$1,220	$2,761	$1,067
2040	$1,958	$1,183	$2,825	$1,081
2041	$1,983	$1,146	$2,889	$1,095
2042	$2,009	$1,109	$2,956	$1,109

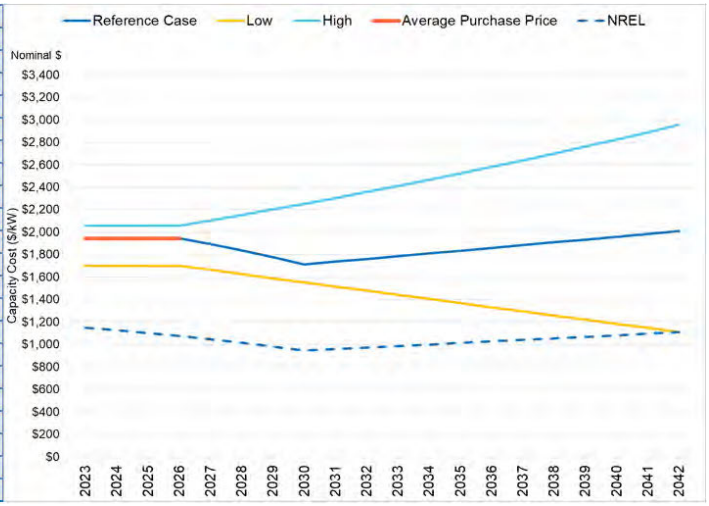
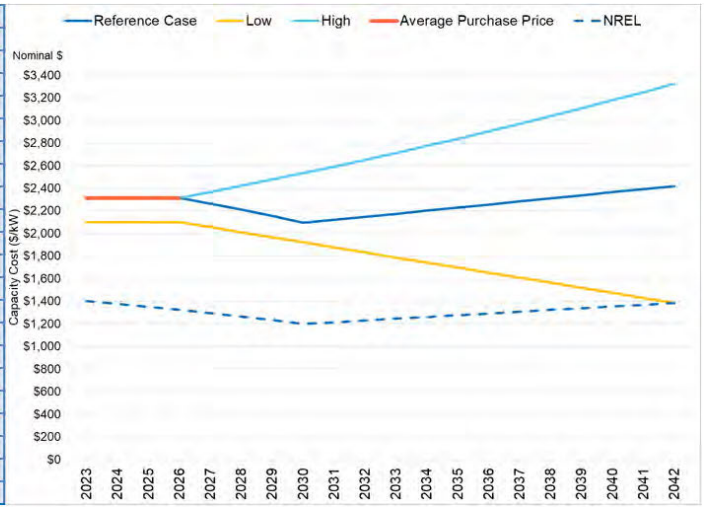


Figure 7.12 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)[67]

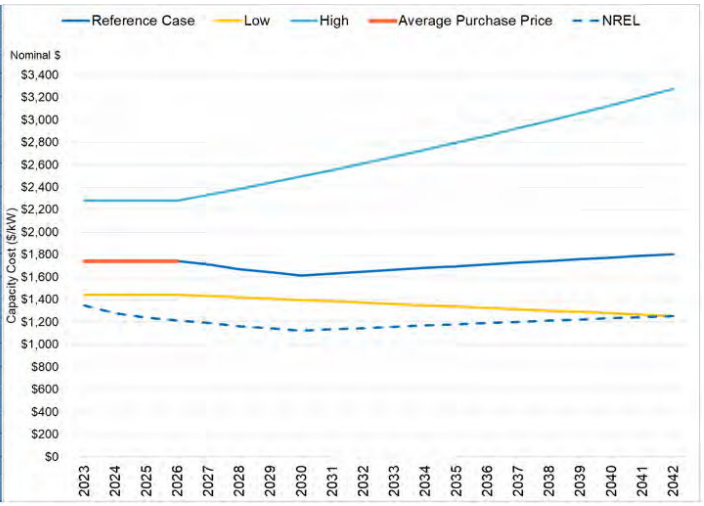
Year	Reference Case	Low	High	NREL
2022	$2,314	$2,100	$2,314	$1,423
2023	$2,314	$2,100	$2,314	$1,400
2024	$2,314	$2,100	$2,314	$1,377
2025	$2,314	$2,100	$2,314	$1,351
2026	$2,314	$2,100	$2,314	$1,325
2027	$2,265	$2,055	$2,367	$1,297
2028	$2,212	$2,011	$2,421	$1,266
2029	$2,155	$1,966	$2,477	$1,234
2030	$2,095	$1,921	$2,533	$1,199
2031	$2,121	$1,877	$2,592	$1,214
2032	$2,148	$1,832	$2,651	$1,230
2033	$2,175	$1,787	$2,712	$1,245
2034	$2,202	$1,743	$2,774	$1,260
2035	$2,229	$1,698	$2,837	$1,276
2036	$2,256	$1,653	$2,903	$1,291
2037	$2,283	$1,609	$2,969	$1,307
2038	$2,310	$1,564	$3,037	$1,323
2039	$2,337	$1,519	$3,107	$1,338
2040	$2,365	$1,474	$3,178	$1,354
2041	$2,392	$1,430	$3,251	$1,369
2042	$2,419	$1,385	$3,325	$1,385



[66] High Regulatory and Market Driven Innovation Scenarios were Low; Decarbonization/Electrification was at Reference Case; and Continued High Inflation & Supply Chain issues was High.
[67] High Regulatory and Market Driven Innovation Scenarios were Low; Decarbonization/Electrification was at Reference Case; and Continued High Inflation & Supply Chain issues was High.

Figure 7.13 – Lithium-Ion 50 MW / 200 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)[68]

Year	Reference Case	Low	High	NREL
2022	$1,742	$1,443	$2,279	$1,434
2023	$1,742	$1,443	$2,279	$1,344
2024	$1,742	$1,443	$2,279	$1,277
2025	$1,742	$1,443	$2,279	$1,236
2026	$1,742	$1,443	$2,279	$1,211
2027	$1,711	$1,431	$2,331	$1,190
2028	$1,669	$1,419	$2,385	$1,160
2029	$1,643	$1,407	$2,439	$1,142
2030	$1,614	$1,395	$2,495	$1,122
2031	$1,632	$1,383	$2,553	$1,134
2032	$1,648	$1,372	$2,611	$1,146
2033	$1,664	$1,360	$2,671	$1,157
2034	$1,680	$1,348	$2,732	$1,168
2035	$1,696	$1,336	$2,795	$1,179
2036	$1,712	$1,324	$2,859	$1,190
2037	$1,727	$1,312	$2,924	$1,201
2038	$1,743	$1,300	$2,991	$1,212
2039	$1,758	$1,289	$3,060	$1,222
2040	$1,773	$1,277	$3,130	$1,233
2041	$1,788	$1,265	$3,202	$1,243
2042	$1,802	$1,253	$3,275	$1,253



[68] High Regulatory and Market Driven Innovation Scenarios were Low; Decarbonization/Electrification was at Reference Case; and Continued High Inflation & Supply Chain issues was High.

SECTION 8
PORTFOLIO DEVELOPMENT AND EVALUATION

8.1 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. Working with external stakeholders and building upon feedback from the IURC Director's Report from the 2019/2020 IRP, CEI South developed 10 portfolios for evaluation that included the use of its last coal plant (status quo) for comparative cost and performance benchmarking purposes, scenario-based portfolios optimized under widely varying market conditions, portfolios designed to provide insights around existing resource decisions, diversified portfolios with a balanced mix of generation technology types and renewables-focused portfolios designed with input from stakeholders. Each portfolio was constructed with the option to include near-term solar, wind and battery storage options, from the All-Source RFP solicitation. Medium-term and long-term resource options were available for selection from a combination of sourcing including the All-Source RFP as well as a comprehensive technology assessment performed by 1898 & Co. used to fill in resource options that were not provided in the RFP (where available from prices used from RFP data and trended based on NREL curves into the future). All portfolios were designed to include energy efficiency and demand response programs. Demand Side Management program options were modeled in addition to resource alternatives. Income Qualified Weatherization ("IQW"), Demand Response Legacy, Demand Response Industrial and Residential Low-Medium were implemented in all portfolios for all model years.

8.1.1 Key IRP Portfolio Decisions

CEI South strived to take into consideration the many diverse interests of a broad range of stakeholders. Candidate portfolios were developed with direct and indirect input from stakeholders. A key decision in the IRP process was the conversion or retirement decision for F.B. Culley 2 and 3. In addition, with MISO's shift to a seasonal construct, CEI South built portfolios to address potential capacity short falls across all seasons. Ultimately, a wide range of deterministic portfolios were created and analyzed to provide insight around the F.B. Culley 2 and 3 decisions along with various future resource mix options.

8.1.2 Scenario-Based and Deterministic Portfolios

Scenario-based portfolios (Reference Case, High Regulatory, Market Driven Innovation, Decarbonization/Electrification, and Continued High Inflation & Supply Chain Issues) were developed to evaluate various regulatory constructs, economic and market conditions and technological progress. In general, the scenario-based portfolios move from Market Driven Innovation to High Regulatory, with intermediate levels of regulation characterized by the Decarbonization/Electrification and Continued High Inflation & Supply Chain Issues portfolios.

While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to bookend the Reference Case with higher than, lower than, or similar inputs to the Reference Case.

Figure 8.1 – Scenario Based Portfolios

Year	Reference Case	Continued High Inflation & Supply Chain Issues	Market Driven Innovation	High Regulatory	Decarbonization/ Electrification
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (200MW) Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Wind (600MW) Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026				Wind (200MW) Solar + Storage (60 MW)	
2027	CCGT Conversion	Wind North (200MW)	CCGT Conversion		CCGT Conversion
2028				Storage (100MW)	
2029	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3 Storage (100MW)	Retire FB Culley 3
2030		Storage (50 MW) Wind North (400MW)			Wind North (200MW)
2031		Storage (10MW)			
2032		Long Duration Storage (300MW)		Long Duration Storage (300MW)	Long Duration Storage (300MW) Wind North (200MW)
2033	Wind North (600MW)	Wind North (400MW)		Wind North (400MW)	Wind North (600MW)
2041			Storage (10MW)	Solar (100MW)	
2042			Storage (10MW)	Solar (200MW)	

In addition to scenario-based portfolios, deterministic portfolios were created to test various solutions to key decisions needed from this IRP. For example, converting F.B.

Culley 2 and/or F.B. Culley 3 to gas, retiring F.B. Culley 2 by 2025, and retiring F.B. Culley 3 by 2029, 2035, or continuing operations were all strategies included in deterministic portfolios. Within these F.B. Culley 3 retirement portfolios, various resource mixes of non-thermal (wind, solar, storage) and thermal (CCGT, CT) were tested. In addition to analyzing different outcomes for F.B. Culley 2 and F.B. Culley 3, A.B. Brown with and without the conversion of the new CTs to a CCGT conversion was considered.

With these various portfolios in mind, additional portfolios and iterations were developed based on 1) stakeholder feedback, 2) lessons learned from preliminary portfolio optimization results, 3) examining tradeoffs in different existing resource decision timing, and 4) continued right sizing portfolios on both capacity and energy. Once these diverse portfolios were created, they were run through the EnCompass model to be analyzed and screened.

8.1.3 Portfolio Screening

After the scenario based portfolios and alternatives were created, they were screened to maintain a reasonable number of portfolios to run through risk analysis. Three different categories were identified to screen out portfolios.

The first step in screening portfolios was to determine where there were portfolios with significant overlap in resource selection. The goal was to include portfolios in the risk analysis that were different enough to provide insights between different resource options. For example, the Reference Case, Market Driven Innovation, and Decarbonization/Electrification portfolios had similar resource selections (A.B. Brown CCGT Conversion in 2027, Retiring FB Culley 3 in 2029, and 200+ MW of Wind in early 2030s) to the Reference Case. Therefore, the Market Driven Innovation and Decarbonization/Electrification portfolios were removed from consideration because they did not provide any additional insights that could not be derived from the Reference Case portfolio.

Next, portfolios were screened based on their size compared to the needs of CEI South and their customers. The portfolio needed to meet seasonal capacity requirements while not significantly overbuilding generation, from either a capacity or energy basis. Several portfolios, which were hundreds of megawatts long on capacity and/or over generated energy compared to CEI South's need throughout study period, were screened out. The scenario-based portfolios High Regulatory and Continued High Inflation & Supply Chain Issues were screened out due to being overbuilt compared to CEI South's capacity needs. Certain resource mixes and portfolio concepts from these portfolios are included in deterministic portfolios at more right sized scale to CEI South's future needs.

The final screening category was cost. Portfolios which were significantly higher on cost when run through the reference case were removed along with portfolios which tested adding or replacing a specific resource that decreased portfolio performance were screened out. This included screening out portfolios that contained hydroelectric resources, which proved to be a very expensive option for CEI South customers. After screening out portfolios, there were 10 portfolios left to further evaluate in the risk analysis.

8.1.4 10 Portfolio Descriptions

The following sections describe in detail designed portfolios (including thermal, diverse and renewables-focused portfolios). Figure 8.2 Risk Analysis Portfolios shows a summary table of the build outs for each of the selected set of portfolios for consideration in the Risk Analysis.

Figure 8.2 – Risk Analysis Portfolios

Year	Reference Case	Business as Usual (BAU) Cont. FB Culley 3 on Coal	Convert F.B. Culley 3 to Natural Gas by 2030	Convert F.B. Culley 3 to Natural Gas by 2027	Convert F.B. Culley 3 to Natural Gas by 2027 with Wind and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Continue FB Culley 3 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2027	CCGT Conversion			Covert FB Culley 3 to Natural Gas	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)
2028					
2029	Retire FB Culley 3	Storage (10MW)			
2030	Storage (10MW)	Wind (200MW)	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)	Wind (200MW) Solar (200MW)	
2032			Wind (200MW)	Wind (200MW)	Wind (200MW)
2033	Wind (400MW)		Wind (200MW)	Wind (200MW)	Wind (200MW)
2041					
2042	Storage (10MW)	Storage (10MW)			

Year	CT Portfolio (Replace FB Culley 3 with F Class CT)	Diversified Renewables	Diversified Renewables (Early Storage & DG Solar)	Replace FB Culley 3 with Storage and Wind	Replace FB Culley 3 with Storage and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2027			Solar (60MW)		
2028			Storage (90MW)		
2029	Retire FB Culley 3	Retire FB Culley 3 Wind (200MW)	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3
2030	F-Class CT Storage (60MW)	Storage (200MW) Solar (200MW) Wind (200MW)	Storage (100MW) Wind (400MW) Solar (100MW)	Storage (300MW) Wind (400MW)	Storage (250MW)
2033	Wind (600 MW)	Wind (200MW)	Wind (200MW)	Wind (200MW)	Solar (300MW)
2041			Solar (100MW)		
2042			Solar (100MW)		Storage (10MW)

8.1.4.1 Reference Case

The Reference Case portfolio was built based on the Reference Case ("most likely" future), built with commodity forecasts based on a consensus outlook from industry experts as described in Section 7.2 Reference Case Scenario. This least cost portfolio converts CEI South's two new CTs to a CCGT in 2027 and retires F. B. Culley 3 by the end of 2029. It also includes a significant amount of renewable resources. More capacity was selected within the model than what was needed until F.B. Culley 3 is retired in 2029 and then is generally in line with CEI South's capacity need in the long term as shown in Figures 8.3 and 8.4. On an energy basis, this portfolio generates much more energy than is needed for CEI South customers, as shown in Figure 8.5.

Figure 8.3 – Reference Case Summer Capacity

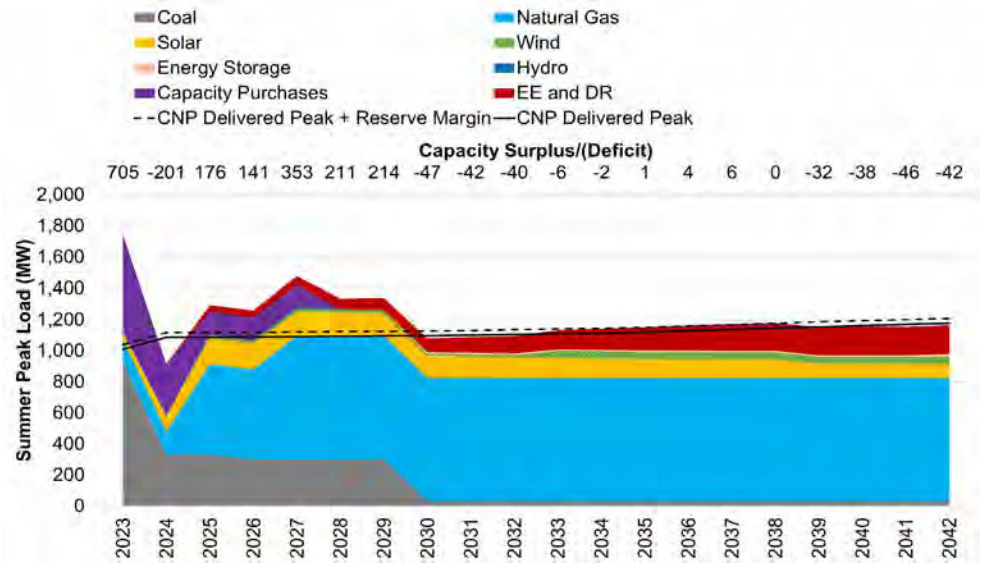


Figure 8.4 – Reference Case Winter Capacity

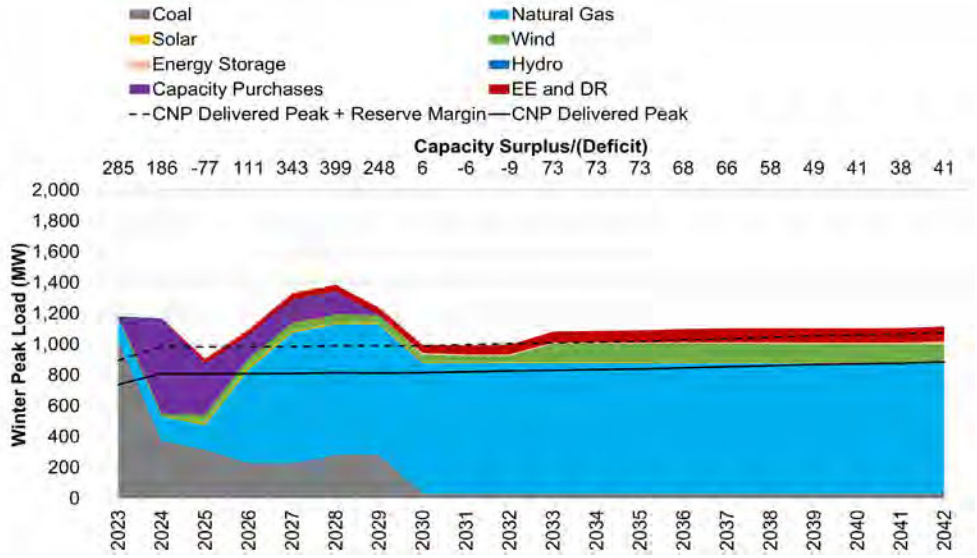
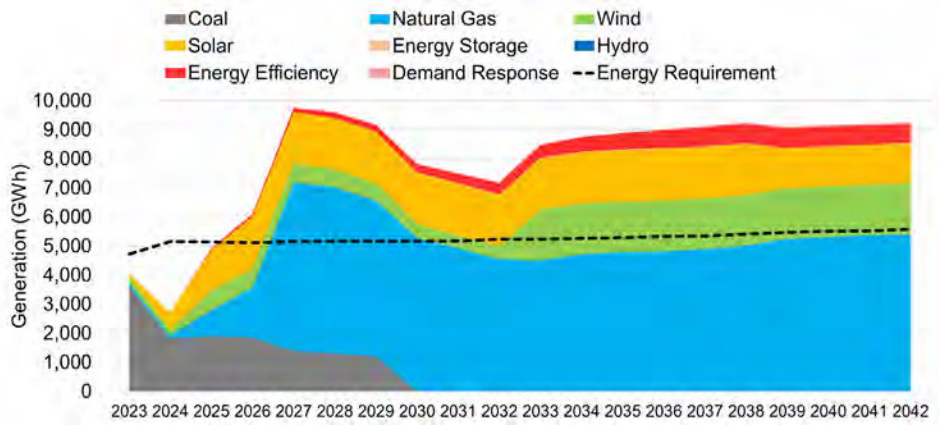


Figure 8.5 – Reference Case Energy (Reference Case Conditions)



8.1.4.2 Business as Usual ("BAU") Continue F.B. Culley 3 on Coal

The BAU portfolio was designed, by definition, to provide a business as usual outlook through the forecast period. In this portfolio, F B Culley 2 is retired in 2025, and F B Culley 3 is kept in operation throughout the study period. This portfolio provides a useful, status quo benchmark for financial and operational performance to compare against all the other candidate portfolios. This portfolio required a small amount of energy storage and added

200 MWs of wind in 2030 to meet capacity and energy requirements. As shown in Figures 8.6-8.8, this portfolio balances the need for energy and capacity well throughout the study period.

Figure 8.6 – BAU Summer Capacity

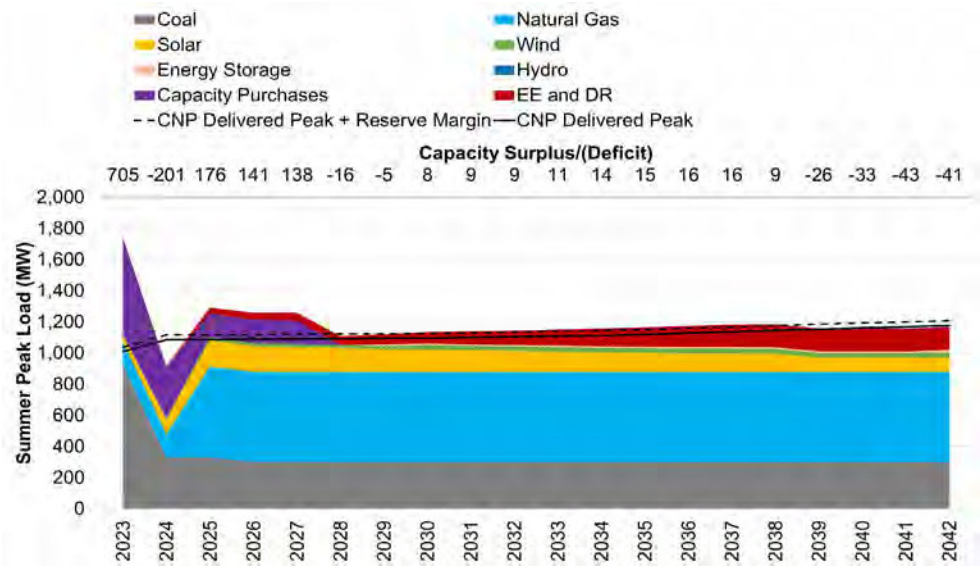


Figure 8.7 – BAU Winter Capacity

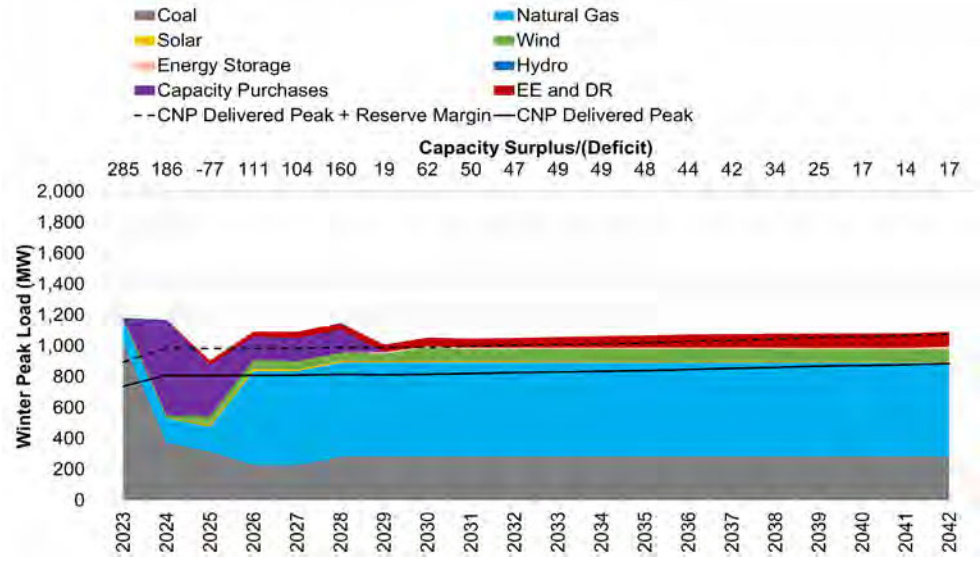
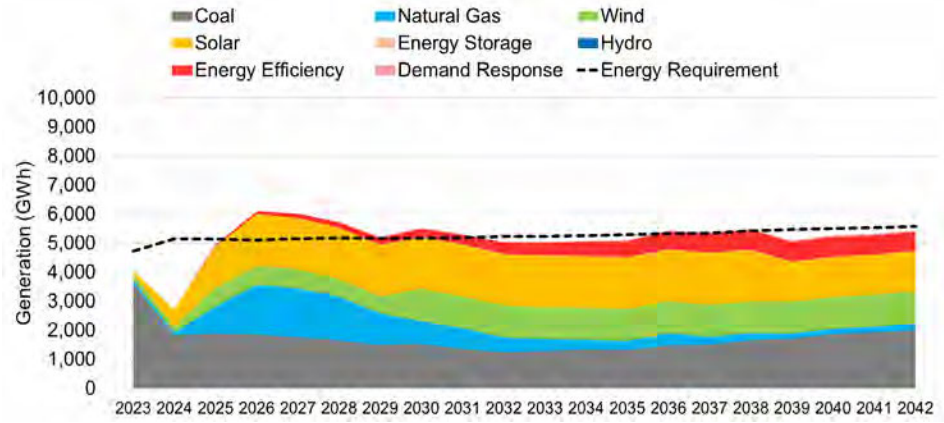


Figure 8.8 – BAU Energy (Reference Case Conditions)



8.1.4.3 Convert F B Culley 3 to Natural Gas by 2030

This portfolio was designed to include the conversion of F B Culley 3 from a baseload coal-fired to natural gas peaking plant, which helps to preserve and repurpose much of the existing asset base. The unit would be converted for operation beginning in 2030 through the end of the study period. This balanced portfolio includes 200 MW of wind and 200 MW of solar in 2030 with two additional 200 MW of blocks of wind in 2032 and 2033, respectively. As shown in Figures 8.9-8.11, this portfolio balances the need for energy and capacity well throughout the study period.

Figure 8.9 – Convert F.B. Culley 3 to Natural Gas by 2030 Summer Capacity

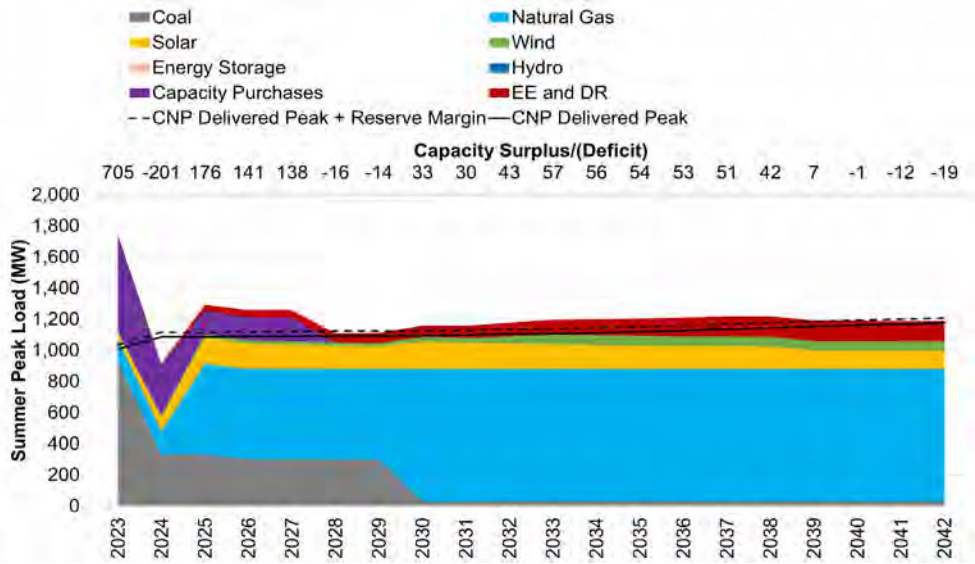


Figure 8.10 – Convert F.B. Culley 3 to Natural Gas by 2030 Winter Capacity

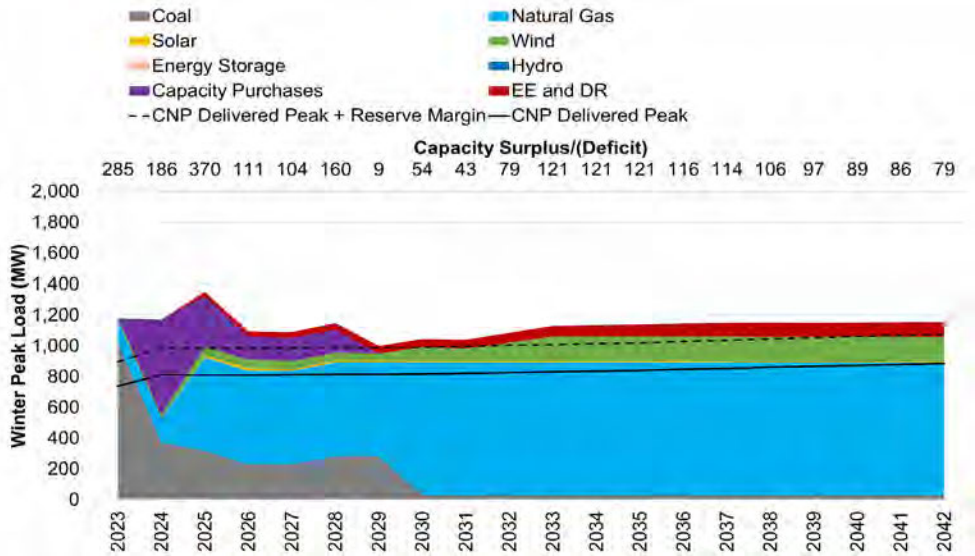
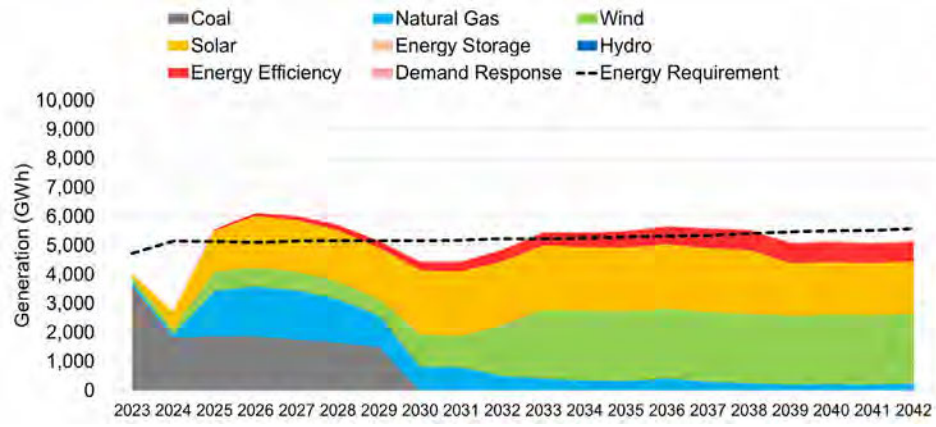


Figure 8.11 – Convert F.B. Culley 3 to Natural Gas by 2030 Energy (Reference Case Conditions)



8.1.4.3.1 Convert F.B. Culley 3 to Natural Gas by 2027

This portfolio was designed to include the conversion of F B Culley 3 from baseload coal-fired to a natural gas peaking plant by 2027 to explore tradeoffs with potential conversion in 2030. All other resources remain the same as the Convert F.B. Culley 3 to Natural Gas by 2030. As mentioned above, the conversion helps to preserve and repurpose much of the existing asset base at this facility. As shown in Figures 8.12-8.13, this portfolio meets capacity obligations well throughout the study period. There is a near to mid-term reliance on the energy market; however, this portfolio contains a high level of dispatchable generation that can help shield customers from high energy prices.

Figure 8.12 – Convert F.B. Culley 3 to Natural Gas by 2027 Summer Capacity

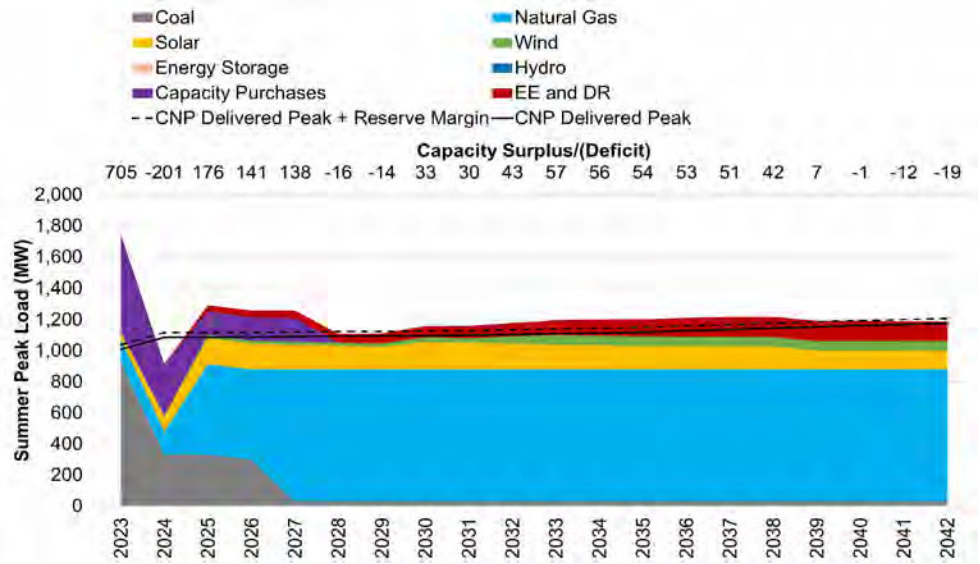


Figure 8.13 – Convert F.B. Culley 3 to Natural Gas by 2027 Winter Capacity

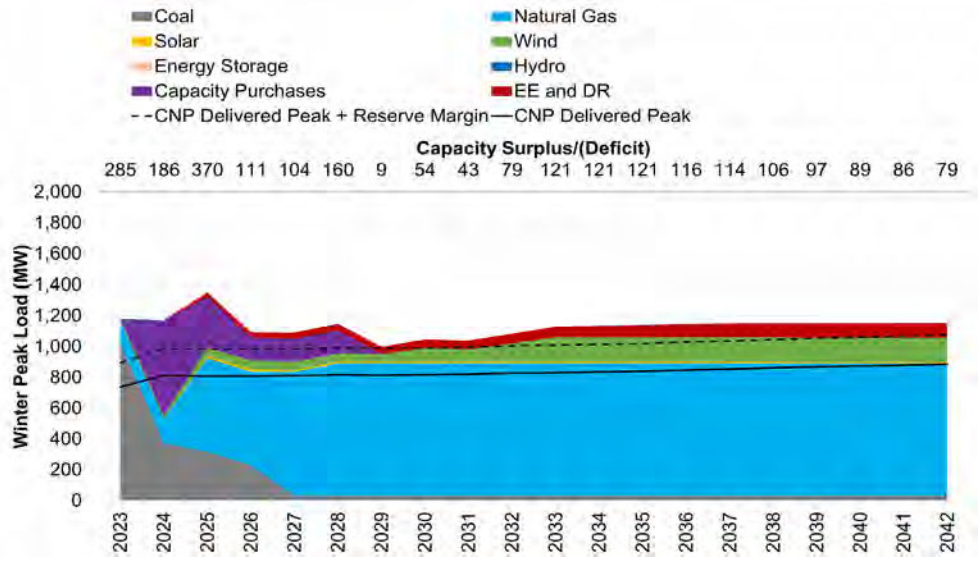
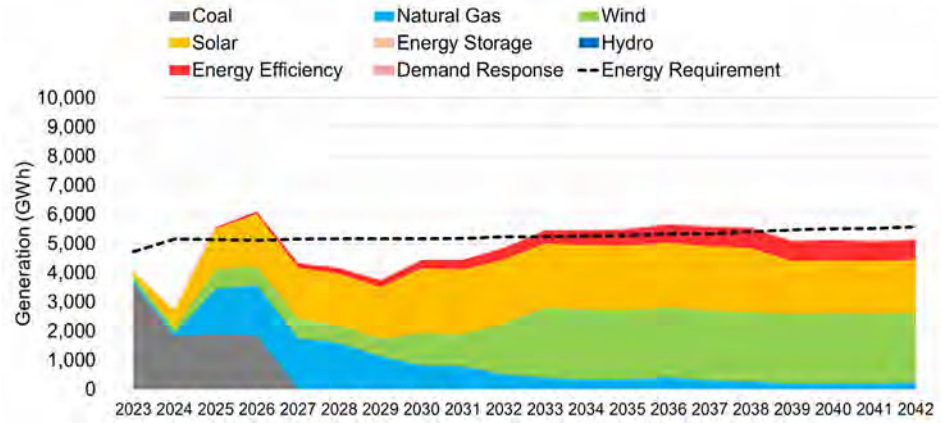


Figure 8.14 – Convert F.B. Culley 3 to Natural Gas by 2027 Energy (Reference Case Conditions)



8.1.4.3.2 Convert F B Culley 3 to Natural Gas by 2027 with Wind and Solar

Like the portfolio before it, this portfolio was designed to include the conversion of F.B. Culley 3 from baseload coal-fired to a natural gas peaking plant by 2027. It pulls forward 200 MWs of solar and 200 MWs of wind from 2030 to 2027 to explore the tradeoff associated with reliance on the market in the near term versus acquiring these renewable resources earlier. All other resources remain the same. As shown in Figures 8.15-8.17, this portfolio meets capacity obligations well throughout the study period.

Figure 8.15 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Summer Capacity

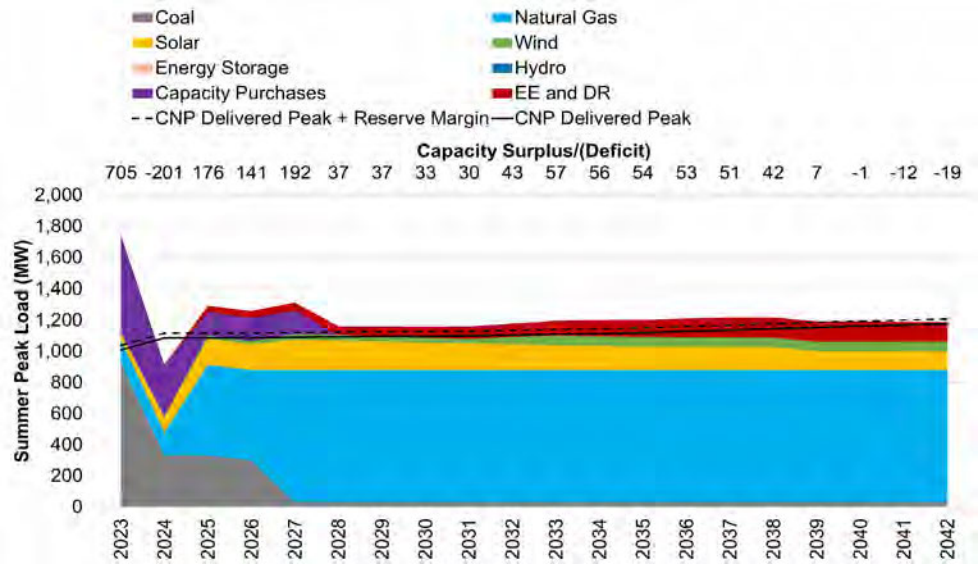


Figure 8.16 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Winter Capacity

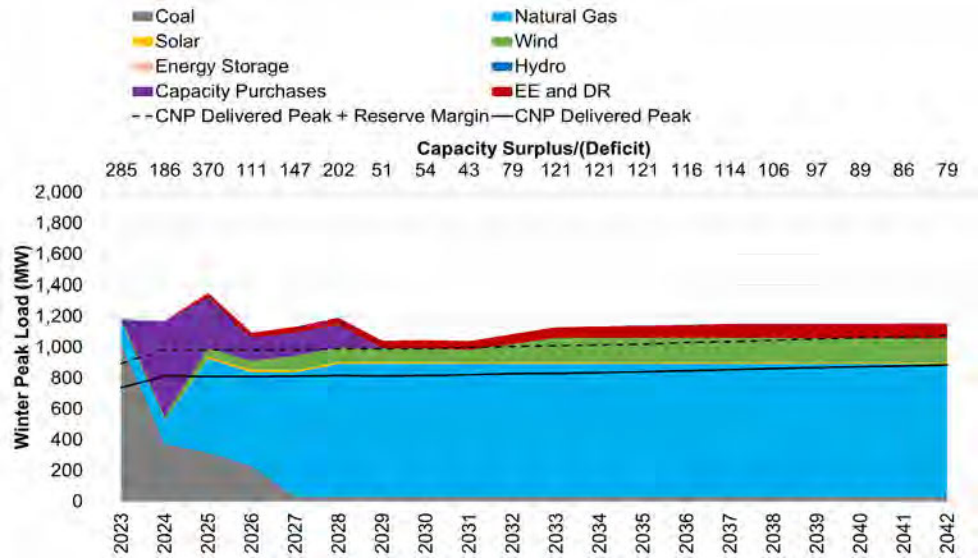
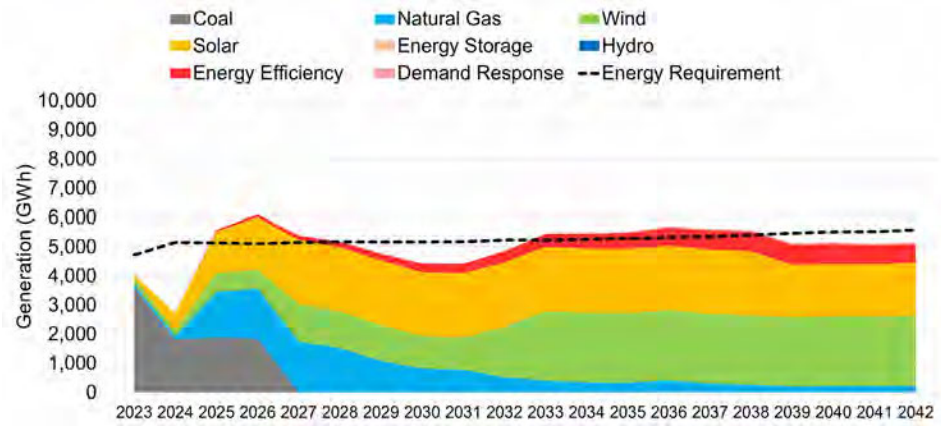


Figure 8.17 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Energy (Reference Case Conditions)



8.1.4.3.3 CT Portfolio (Replace F B Culley 3 with F-Class CT)

The CT Portfolio was included to evaluate the replacement of F.B. Culley 3 with a new approximately 230 MW F-Class Combustion Turbine. This portfolio strategy provides a transition pathway to a generation fleet without operating coal, while maintaining and adding a diverse fuel mix of generation technologies, which include a 60 MW battery in 2030 and 600 MWs of wind in 2033. As shown in Figures 8.18-8.20, this portfolio meets capacity obligations well throughout the study period. There is a near to mid-term reliance on the energy market; however, this portfolio contains a high level of dispatchable generation that can help shield customers from high energy prices. The F-class CTs in this portfolio can start fast and ramp quickly.

Figure 8.18 – CT Portfolio (Replace F B Culley 3 with F-Class CT) Summer Capacity

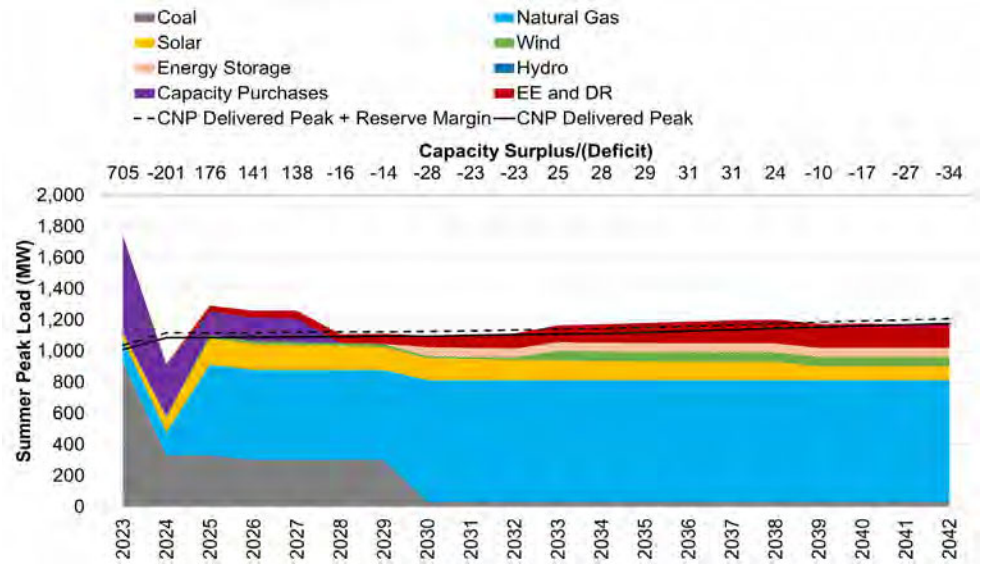


Figure 8.19 –CT Portfolio (Replace F B Culley 3 with F-Class CT) Winter Capacity

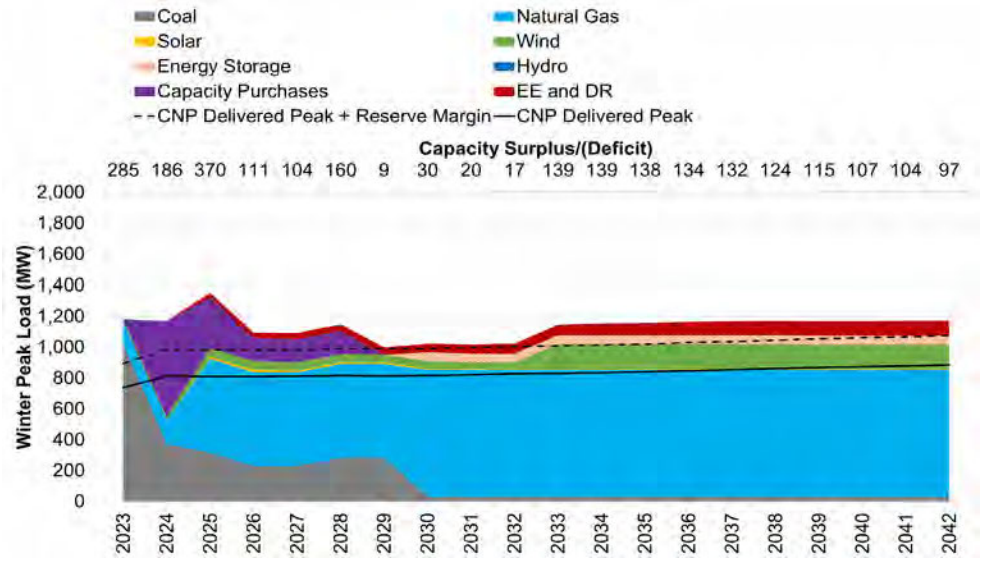
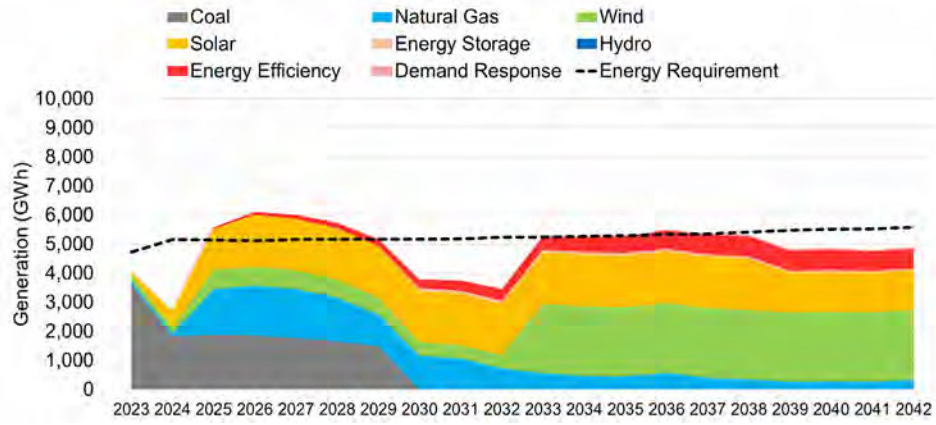


Figure 8.20 –CT Portfolio (Replace F B Culley 3 with F-Class CT) Energy



8.1.4.3.4 Diversified Renewables

The Diversified Renewables portfolio was designed to transition CEI South's new generation additions to 100% renewables and battery storage beginning in 2030. To meet capacity and energy obligations when F.B. Culley 3 retires in 2029, the portfolio includes a large amount of storage, wind and solar, as shown in Figures 8-20 to 8-23. 200 MWs of wind comes in 2029, followed by 200 MWs of storage, 200 MWs of solar, and 200 MWs of additional wind in 2030. By 2033 another 200 MW wind resource is acquired. As described in Section 6.4.3 this portfolio, a portfolio with a large battery at the F.B. Culley Power Plant site would require system upgrades to support charging.

Figure 8.21– Diversified Renewables Summer Capacity

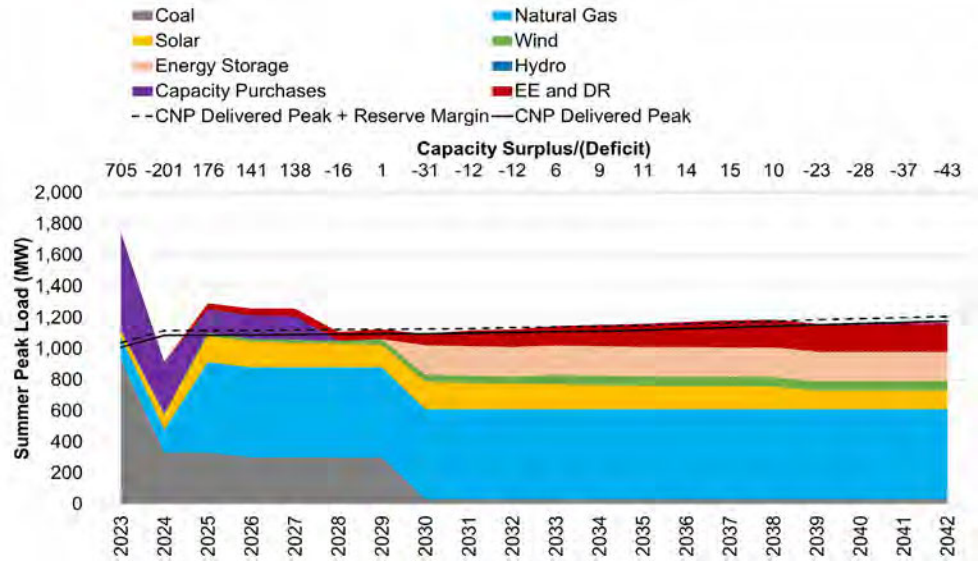


Figure 8.22– Diversified Renewables Winter Capacity

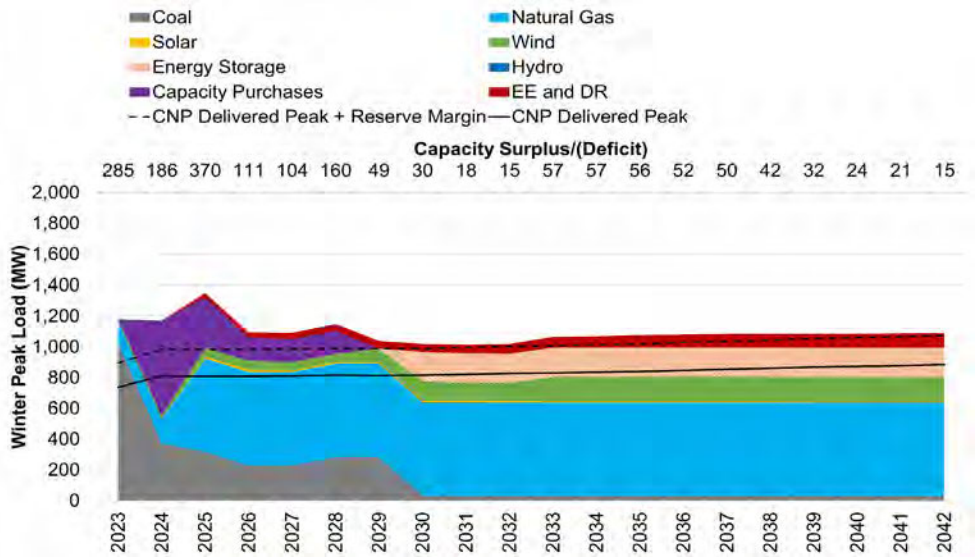
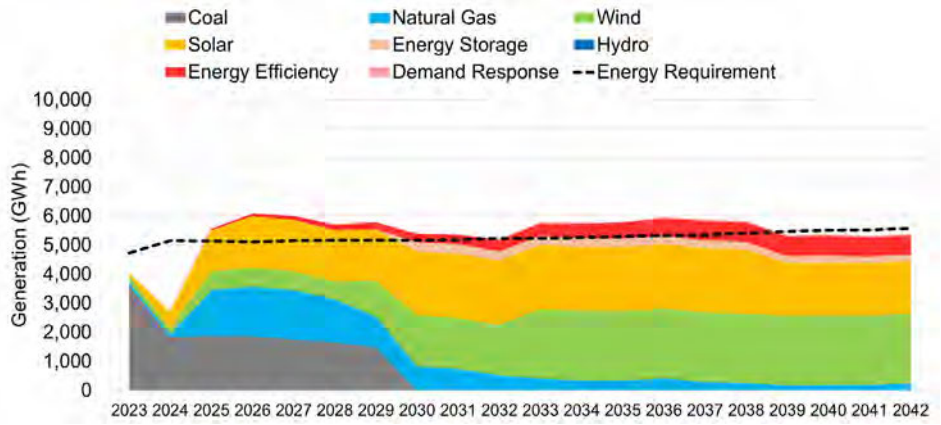


Figure 8.23– Diversified Renewables Energy



8.1.4.3.5 Diversified Renewables (Early Storage & DG Solar)

The Diversified Renewables (Early Storage & DG Solar) portfolio was designed to transition CEI South's generation fleet to renewables and battery storage by adding early storage and distributed generation from solar. The early storage is meant to replace F.B. Culley 2, preserving the interconnection rights at that site. Additionally, it includes distributed solar resources early in the planning period. Beyond that, this portfolio includes

an additional 100 MW battery, 400 MWs of wind, and 100 MWs of solar to replace F.B. Culley 3, which closes in 2029. The portfolio also includes more renewable resources in 2033-2042. The portfolio meets capacity and energy obligations, as shown in Figures 8.24-8.26.

Figure 8.24– Diversified Renewables (Early Storage & DG) Summer Capacity

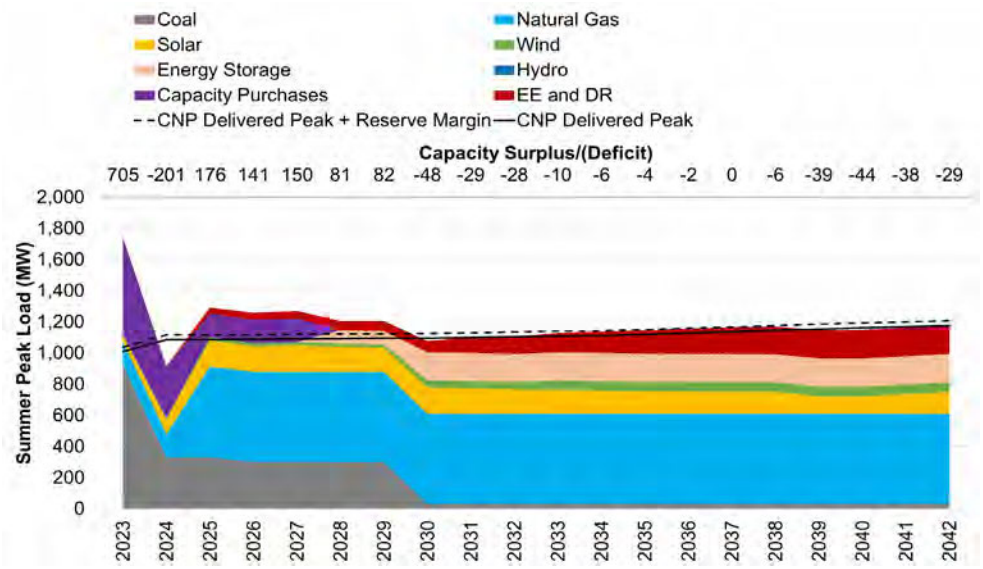


Figure 8.25– Diversified Renewables (Early Storage & DG) Winter Capacity

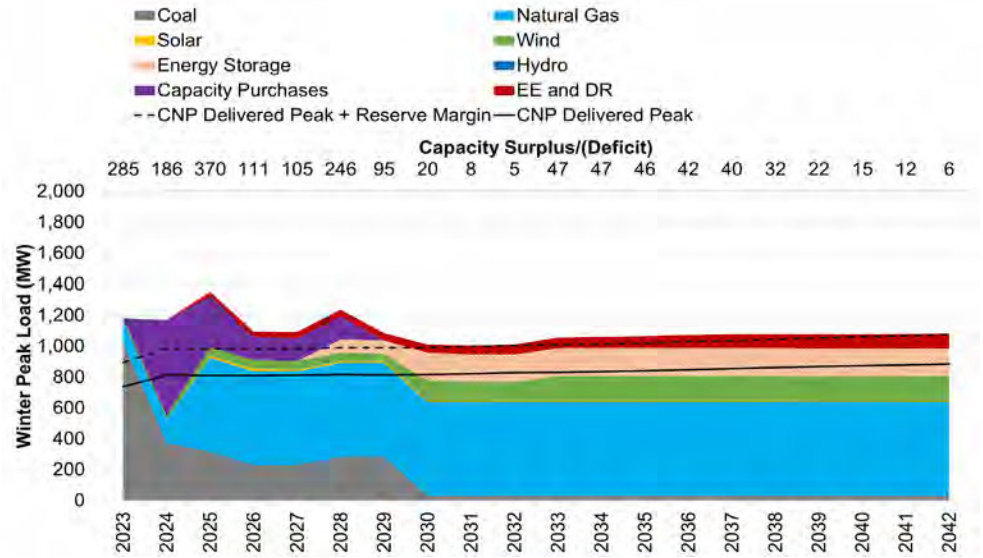
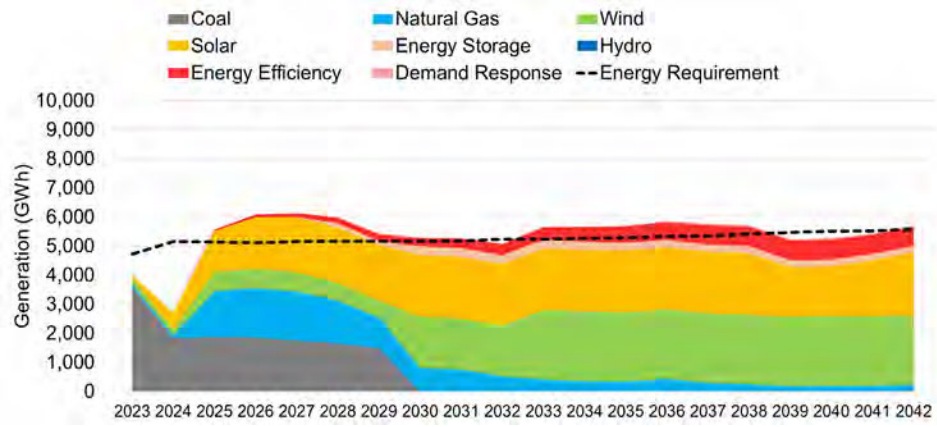


Figure 8.26– Diversified Renewables (Early Storage & DG) Energy



8.1.4.3.6 Replace F B Culley 3 with Storage and Wind

The Replace F B Culley 3 with Storage and Wind portfolio retires F.B. Culley 3 in 2029 and replaces it with 300 MWs of storage and 400 MWs of wind in 2030. Additionally, 200 MWs of additional wind is included within this portfolio in 2033. The portfolio does a good job of meeting both capacity and energy requirements as shown in Figures 8.27 – 8.29.

Figure 8.27– Replace F B Culley 3 with Storage and Wind Summer Capacity

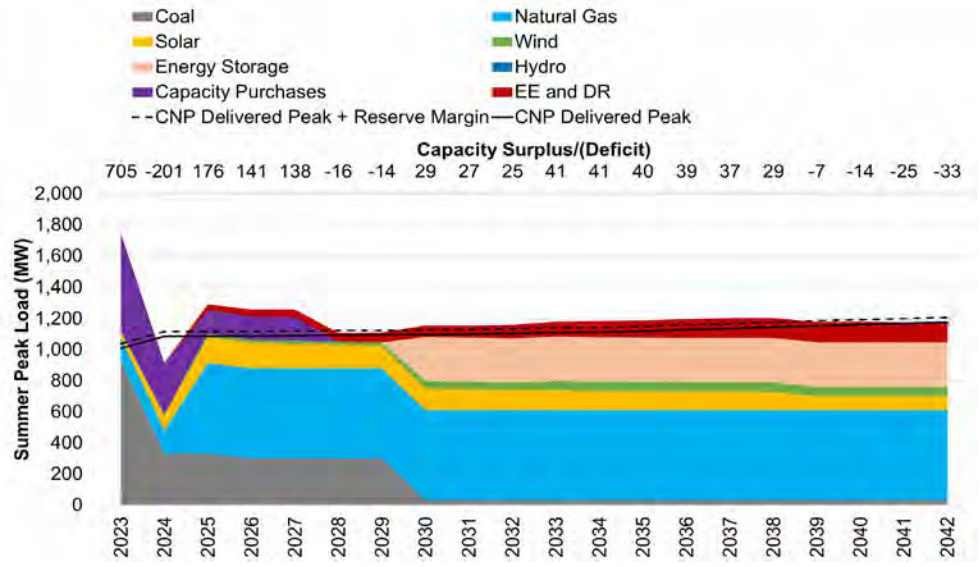


Figure 8.28– Replace F B Culley 3 with Storage and Wind Winter Capacity

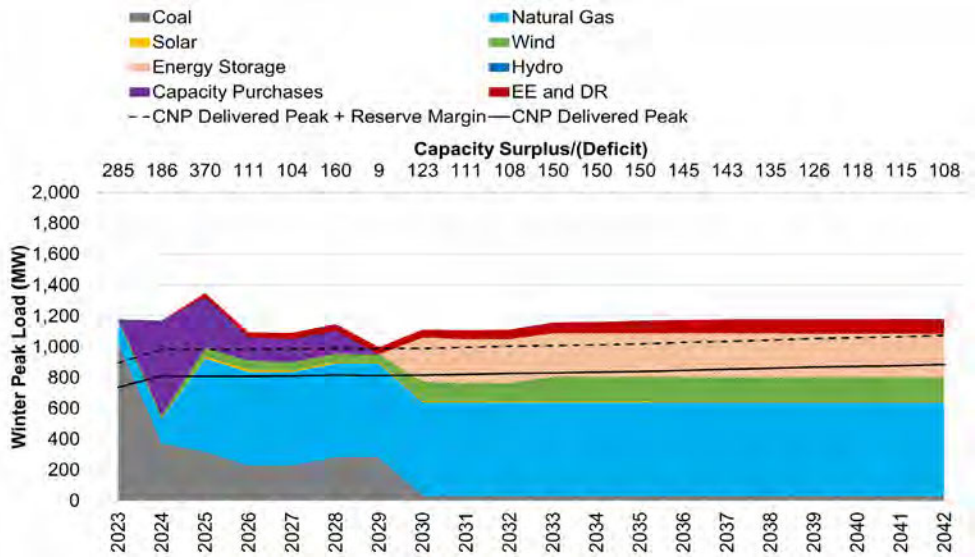
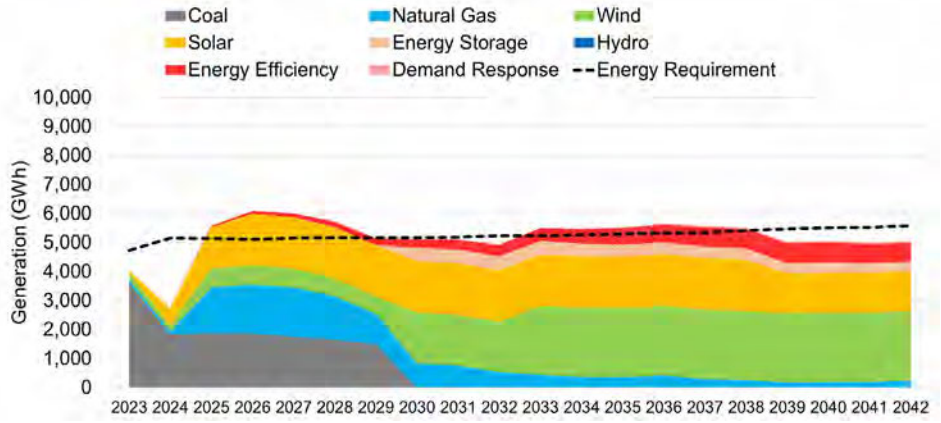


Figure 8.29– Replace F B Culley 3 with Storage and Wind Energy



8.1.4.3.7 Replace F B Culley 3 with Storage and Solar

The Replace F B Culley 3 with Storage and Solar portfolio retires F.B. Culley 3 in 2029 and replaces it with 250 MWs of storage in 2030 includes 300 MWs of solar in 2033. This portfolio meets capacity obligations over time; however, it is heavily reliant on the market for energy over the remainder of the planning period once F.B. Culley 3 is replaced, as shown in Figure 8.32.

Figure 8.30– Replace F B Culley 3 with Storage and Solar Summer Capacity

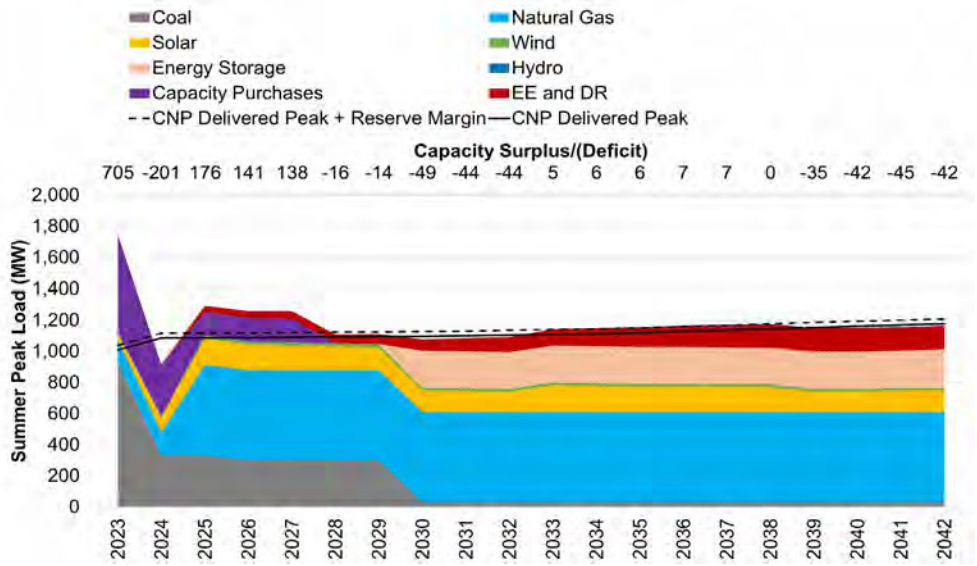


Figure 8.31– Replace F B Culley 3 with Storage and Solar Winter Capacity

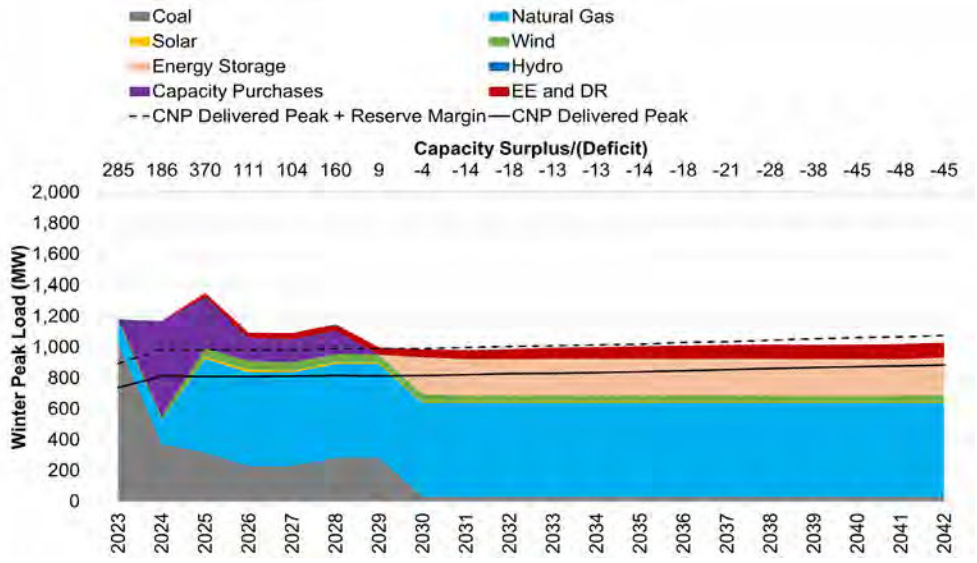
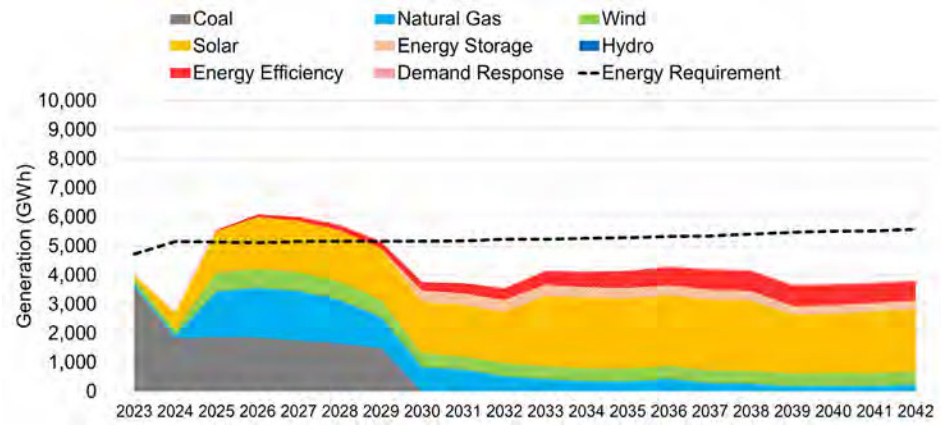


Figure 8.32– Replace F B Culley 3 with Storage and Solar Energy



8.2 EVALUATION OF PORTFOLIO PERFORMANCE

Each of the risk analysis candidate portfolios were subjected to two different forms of risk analysis. One was scenario-based, and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard.

8.2.1 Scenario Risk Analysis

The IRP requires scenario-based modeling be performed as a part of the risk analysis. In the scenario-based risk analysis, the remaining ten candidate portfolios that were selected for further analysis were modeled under each of the five scenarios with their respective market inputs. The following provides a summary of the results of this scenario-based risk analysis. The results shown in Figures 8-33 – 8.34 are the net present value revenue requirement ("NPVRR") and the carbon production throughout the study period in each scenario. The preferred portfolio performed well across all potential futures. Natural gas forecast in the High Regulatory and the Inflation and Supply Chain Issues Scenarios increase by an average of 78% and 29% respectively. This could signal that a natural gas conversion would not be economic. Under the conversion to peaking generation, the unit operates roughly 1% of the time, which greatly improves the carbon output of the portfolio and limits exposure to these costs. The renewable buildout of the portfolio also helps to shield customers from this cost risk by providing the vast amount of energy needed to support customer loads.

Figure 8-33 – Portfolio NPVRR (million $)

Portfolio	Reference	Market Driven Innovation	Decarbonization/ Electrification	High Regulatory	Inflation and Supply Chain Issues
Reference Case	$4,120	$3,923	$4,391	$4,938	$4,327
Replace FB Culley 3 with Storage and Solar	$4,277	$4,104	$5,038	$5,930	$4,701
F-Class CT	$4,321	$4,099	$4,924	$5,624	$4,609
Convert F.B. Culley 3 to Natural Gas by 2030	$4,331	$4,128	$4,850	$5,461	$4,616
Business as Usual	$4,325	$4,190	$5,146	$6,011	$4,428
Convert F.B. Culley 3 to Natural Gas by 2027	$4,341	$4,120	$4,834	$5,452	$4,646
Diversified Renewables	$4,390	$4,248	$4,876	$5,453	$4,831
Replace FB Culley 3 with Storage and Wind	$4,370	$4,251	$4,929	$5,596	$4,862
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,437	$4,206	$4,883	$5,405	$4,660
Diversified Renewables (Early Storage & DG Solar)	$4,485	$4,331	$4,978	$5,552	$4,939

Figure 8-34 – Portfolio Total CO_2 Emissions Throughout the Study Period

CO2 (Tons)	Reference	Market Driven Innovation	Decarbonization/ Electrification	High Regulatory	Inflation and Supply Chain Issues
Reference Case	43,998,248	45,249,902	39,885,693	31,425,636	41,209,220
Replace FB Culley 3 with Storage and Solar	20,815,471	23,978,288	15,126,039	9,113,029	19,338,865
F-Class CT	21,883,367	26,519,310	16,845,029	9,913,288	19,942,549
Convert F.B. Culley 3 to Natural Gas by 2030	20,915,819	23,654,435	15,288,780	9,447,350	19,386,506
Business as Usual	40,987,565	29,503,845	15,682,713	15,289,387	41,614,200
Convert F.B. Culley 3 to Natural Gas by 2027	16,111,764	21,216,414	15,234,745	8,253,657	14,006,533
Diversified Renewables	20,783,694	23,642,166	15,000,146	9,084,486	19,309,689
Replace FB Culley 3 with Storage and Wind	20,852,703	23,982,021	15,133,020	9,136,079	19,343,788
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	16,041,055	21,148,848	15,117,504	8,220,479	13,922,764
Diversified Renewables (Early Storage & DG Solar)	20,742,008	23,729,672	15,068,589	9,077,265	19,284,001

8.2.2 Sensitivity Analysis

Several sensitivities were conducted on the candidate portfolios to test and refine the design of the portfolios and whether and how results might change if isolated variables might change. The following section describes these sensitivities and the conclusions drawn from this analysis, as well as any impact on the candidate portfolios.

The All-Source RFP resulted in several solar, wind and battery storage resources that were included as near-term resources in the optimization module of the EnCompass model. Storage resources have experienced price volatility due to the impacts of the Inflation Reduction Act on investment tax credits. If CEI South is unable to fully monetize the tax credit, the credits may be sold to the market, or to other third party options resulting in less than the full amount of the investment tax credit. A sensitivity was performed in which storage options received 85% of the full investment tax credit. The decrease in storage tax credit monetization only impacts portfolios that included storage, and these portfolios NPV's saw less than a 1% increase in NPV due to the adjusted ITC, around a .1% increase per 100 MW of storage included in the portfolio.

A sensitivity was performed to test the impact of increases in wind cost on portfolio NPV and resource decisions. Based on this analysis, if wind costs were to increase, alternate resources, such as solar or storage resources, would be selected to meet planning reserves with little to no NPV impact on the portfolio.

Given the potential changes in the New Source Performance Standard 111B, nearly half (80 out of 200) of the probabilistic risk analysis simulations included a carbon tax. The introduction of a carbon tax as a proxy for potential change in legislation helps quantify the magnitude of the impact portfolios would be exposed to under more stringent emission regulations. From this sensitivity each of the 10 portfolios saw a 16% to 26% increase in NPV. Both the portfolios including the conversion of F.B. Culley 3 to natural gas and portfolios with high renewable dependency experienced less cost risk than the portfolio that continues operation of F.B. Culley 3 on coal.

A sensitivity was run on the impact of a lower capacity accreditation for battery storage over the study period. The base battery storage accreditation included in the modeling was 95% throughout the study period. It is expected that with MISO's shift to a seasonal construct and reviewing of renewable and storage accreditation methodology, there is potential that battery accreditation will decrease in the future. For modeling of this sensitivity, a declining capacity accreditation was applied. The updated capacity accreditation starts at 100% in 2023 and decreases from 2028 until 2037 to 75% where it remains for the rest of the study period. These annual battery storage capacity accreditation values were utilized by MISO in their MISO Futures Report LRTP Tranche 2 Refresh[69]. When the capacity accreditation is updated from 95% to the declining curve, portfolios which include storage are more reliant on market capacity purchases or would need to procure additional resources to meet CEI South's capacity needs. The reduction of capacity accreditation in the out years from 95% to 75% results in increased portfolio costs of up to 2.9%. Future seasonal capacity accreditations for 4-hour storage are difficult to quantify in MISO, but as more storage is added to the system it is expected to decline. In some regions of the US storage capacity accreditation is projected to decline even further than the 75% accreditation used in this sensitivity.

To simulate a possible increase in customer demand a final sensitivity was conducted to evaluate the impacts of a large industrial customer coming online in 2028. 300 MW of additional load was added to the Reference Case load forecast in 2028 and remains online throughout the study period. The model was allowed to optimize unconstrained to compare project selections given this load addition. To meet this demand AB Brown 5 and AB Brown 6 were converted from existing CTs to a CCGT and an additional J-Class CT was added.

[69] MISO; LRTP Tranche 2 – Futures Refresh Assumptions Book; Last Updated April 27, 2023 https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf

8.2.3 STOCHASTIC (PROBABILISTIC) RISK ASSESSMENT

After selecting the 10 portfolios for further consideration and completion of the deterministic (Scenario based) risk assessment and sensitivities, the remaining step is to conduct the 200 iteration or scenario risk assessment and complete the balanced scorecard, consider “other” relevant factors and select the preferred portfolio given this information.

A more comprehensive risk analysis, using 200 iterations or scenarios, was utilized to provide a more comprehensive assessment of how the 10 portfolios performed under a range of conditions. As with any analysis, the risk analysis and the balanced scorecard that is developed from it, does not provide CEI South with an answer, but rather it is intended to provide insights into tradeoffs associated with a variety of portfolios over a range of future conditions.

The relevant information is provided in many of the metrics in the balanced scorecard. The benefit of conducting the stochastic risk assessment is that CEI South can get a clearer picture of the tradeoffs between least cost, the cost uncertainty (measured by the 95th percentile of cost outcomes over the planning horizon), the carbon equivalent profile of the portfolios and the percentage dependence on energy and capacity purchases and sales of the portfolios based on the probabilistic range of potential outcomes. After this comparison there is also a discussion of other factors that must be considered, like diversity, flexibility, and optionality to adapt to conditions that might cause uneconomic assets.

A summary of how the ten candidate portfolios performed against each of the above metrics is provided in the table below:

Figure 8-35 – IRP Portfolio Balanced Scorecard Color-Coded Comparison

Scorecard - Ranked	Affordability / Cost Risk				Environmental Sustainability		Reliability				Market Risk Minimization							
Portfolio	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)[1]	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2/kwh)[2]	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2)[3]	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4] Summer	Winter	Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]	Energy Market Purchases[7] Average	Near Term Max	Long Term Max	Energy Market Sales[7] Average	Near Term Max	Long Term Max	Capacity Market Purchases or Sales (%)[8] Purchases	Sales
Reference Case	$4,214	0.0%	56%	$4,952	0.00024	33,199,947	97	62	11	919	12%	24%	18%	33%	42%	41%	1.2%	12%
F-Class CT	$4,499	6.7%	30%	$5,413	0.00018	17,975,167	80	22	758	900	28%	40%	46%	17%	21%	24%	0.8%	11%
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.8%	27%	$5,316	0.00015	15,506,174	60	21	469	941	26%	39%	32%	19%	22%	27%	0.6%	12%
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	7.0%	27%	$5,332	0.00016	16,953,911	60	21	469	941	25%	35%	32%	19%	22%	27%	0.6%	12%
Replace FB Culley 3 with Storage and Solar	$4,539	7.7%	29%	$5,416	0.00018	15,917,099	101	137	720	671	38%	43%	49%	13%	21%	17%	1.7%	8%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	8.2%	25%	$5,347	0.00014	15,382,405	60	21	469	941	24%	31%	32%	20%	24%	27%	0.6%	13%
Replace FB Culley 3 with Storage and Wind	$4,580	8.7%	26%	$5,328	0.00015	15,931,427	74	9	769	671	27%	35%	33%	15%	21%	21%	0.7%	12%
Business as Usual	$4,581	8.7%	35%	$5,486	0.00025	23,897,336	90	74	480	941	31%	35%	36%	14%	21%	19%	0.9%	10%
Diversified Renewables	$4,583	8.8%	25%	$5,313	0.00015	15,763,426	89	71	669	671	25%	31%	30%	18%	22%	24%	1.1%	9%
Diversified Renewables (Early Storage & DG Solar)	$4,676	11.0%	25%	$5,408	0.00015	15,766,880	94	81	659	671	25%	34%	30%	18%	22%	24%	1.2%	9%

1: Total energy generation from coal and gas / total fleet generation from 2023 - 2042
2: Average CO_2e from generation / average fleet generation from 2030 - 2042
CO_2e shown in metric tons
3: Sum of CO_2e emissions from 2023 - 2042
4: Maximum seasonal capacity deficit in summer/winter from 2030 - 2042
5: Average MW of installed battery, CT, recip capacity from 2030 - 2042
6: Average MW of dispatchable resources from 2030 - 2042
7: Average GWh energy market interaction / total energy + sales from 2023 - 2042
Near Term: 2026 - 2030
Long Term: 2031 - 2042
8: Average capacity market purchases / coincident peak demand from 2023 - 2042

A color-coded comparison (conducted automatically by the spreadsheet) of the balanced scorecard is shown above in Figure 8-35. Green indicates scoring well relative to other portfolios within the same metric and red 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 for that metric is displayed. For more information on this analysis, please see the final stakeholder presentation in Technical Appendix 3.

SECTION 9
IRP PREFERRED PORTFOLIO

9.1 PREFERRED PORTFOLIO RECOMMENDATION

Based upon several factors, CEI South's preferred portfolio is the convert F.B. Culley 3 by 2027 portfolio.

9.1.1 Description of the Preferred Portfolio

The new and existing supply and demand resources in the preferred portfolio includes conversion of F.B. Culley 3 (270 MW) to natural gas by 2027, 200 MW of wind resources and 200 MW of solar by 2030, and an additional 400 MWs of wind generation between 2031 and 2032. These supply side resources are complemented by demand side resources, demand response and energy efficiency. Approximately 1.1% of energy efficiency was selected in the near-term time period (2025-2027) across three sector (commercial, residential, income-qualified) categories with residential further grouped by low to high cost bundles. The second vintage period (2028-2030) selected approximately 1.2% of energy efficiency bundles and approximately 1.1% of energy efficiency bundles are selected in the long-term (2031-2042). In addition, low Income energy efficiency is included in all periods. The optional demand response bin is selected in the time periods 2028-2030 and 2031-2042, while a DLC program called Summer Cycler is transitioned to Wi-Fi thermostats over time.

The preferred portfolio (Convert F.B. Culley 3 by 2027) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The preferred portfolio was within 7 percent of the lowest cost portfolio and a tenth of a percent from the next lowest option. It ranks 3 out of 10 (third best) in the 95th percentile cost risk metric. It does not over-rely on either purchases or sales of energy or capacity. The preferred portfolio maintains 270 MWs of 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.

Importantly it provides the flexibility and optionality in the future MISO system adapts to higher levels of renewables across the system, allowing more time for other technologies,

like long duration battery storage, to be commercialized. By having the option to retire F.B. Culley 3 provides CEI South on offramp in the future to move when needed to a portfolio with less reliance on fossil resources.

The preferred portfolio is among the best performing portfolios across multiple measures on the balanced scorecard and provides a number of additional benefits to CEI South customers and other stakeholders, including that it:

- Eliminates dependence on coal-fired generation in a prompt timeframe, allowing customers to enjoy the benefits of renewable energy, while ensuring continued reliable service as CEI South continues to move toward higher levels of intermittent renewable energy in the future. Dispatchable generation with firm gas service at F.B. Culley will allow this resource to be available to meet peak conditions during long duration weather events.
- Saves customers nearly $80 million over the next 20 years when compared to continued operation of F.B. Culley with coal and avoids $170 million of cost risk over this time period. The preferred portfolio is among the lowest cost portfolios.
- Reduces CO_2 equivalent emissions, which includes methane, by nearly 95% over the next 20 years. Direct carbon emissions are reduced 98% from 2005 levels by 2035. The portfolio prevents over 9 million tons of CO_2 from entering the atmosphere as compared to continuing to run F.B. Culley 3 with coal.
- Includes a diverse mix of resources (solar, wind and energy efficiency, supported by fast-start gas, peaking gas generation, and demand response); protects against overreliance on the market for energy and capacity.
- 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 of Culley 3 in the future when appropriate based on continual evaluation of changing technology and conditions.
- The preferred portfolio performed consistently well across a wide range of potential future environmental regulations, including CO_2, methane and fracking.

- 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 1.1% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. 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.
- Explores new options to help manage loads in the future with the potential for new demand response resources, working with an aggregator to better partner with commercial and industrial customers to tap additional potential and include a pilot to evaluate the potential of time-based rates.

9.1.2 Affordability

Affordability is a key objective in the balanced scorecard and that is measured as part of the stochastic analysis. The measure for affordability is the 20-year NPVRR, which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is run 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 revenue and capacity market purchases 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 recuperate 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 Reference case portfolio, which converts CEI South's two F-class combustion turbines into a large, combined cycle, was found to be the least cost portfolio by a wide margin across multiple potential future states; however, CEI South does not plan to convert either or both CTs to a combined cycle in the absence of a large load addition. The reference case, generated by computer modeling, is overbuilt for CEI South customer needs and relies on vastly more market energy sales to lower the NPVRR well below all other portfolios. The Indiana Commission instructed that this is a risky proposition for a company of this size in Cause No. 45052. CEI South's preferred portfolio complies with this view.

The preferred portfolio was determined to be among the lowest cost portfolios across the 10 candidate portfolios, with a 20-year NPVRR of $4,502 million. This NPVRR is 6.7% higher than the Reference case portfolio but only 0.1% higher than the next lowest cost portfolio, a difference of less than $4 million over 20 years on a net present value basis. The preferred portfolio is nearly $80 million less expensive than the Business as Usual which continues F.B. Culley 3 on coal (the eighth most expensive portfolio in this objective category), which saves customers money in the long term.

9.1.3 Future Affordability (Cost Risk)

The Cost Risk minimization objective is measured in a similar way to the Affordability objective, using the 20-year NPVRR values from the stochastic analysis. However, this objective provides a measure of the 95th percentile of the NPVRR to determine an upper boundary (or worst-case perspective) of portfolio costs across the 200 stochastic iterations. The Cost Risk Minimization objective can be interpreted as follows: There is a 95% chance that total portfolio costs as measured by the 20-year NPVRR will be at or below this measure. In this way, the risk that total portfolio costs over 20 years can be measured, allowing for the selection of a portfolio that minimizes this risk. This in turn minimizes the risk that rates (prices) will be higher than the expected, where expected rates (costs) come from the Affordability objective.

The preferred portfolio performed well in the Cost Risk Minimization category. The 95th percentile of the 20-year NPVRR was determined to be $5,316 million, which is 7.4% higher than the Reference Portfolio 95th percentile of the 20-year NPVRR and within 0.1% ($3 million) of the next lowest cost portfolio. For this same objective, the preferred portfolio was found to be $170 million less than the Business as Usual portfolio, which is also the most expensive portfolio in this objective category. Accordingly, the preferred portfolio is shown to have a low level of cost risk relative to its own expected NPVRR as well as relative to the least cost portfolio, the most expensive portfolio and all other candidate portfolios.

In addition to the Revenue Requirement, the exposure to coal and gas markets must also be considered when evaluating cost risk. As commodity markets become more volatile the exposure to these market fluctuations may pose a risk to the overall portfolio. The portion of energy generation with exposure to these market risks was calculated using the total generation from coal and gas units divided by total fleet generation throughout the study period. The preferred portfolio performed well in this market risk category. The portfolio exposure to coal and gas markets was determined to be 27% of total generation. This shows a 29% decrease in exposure to coal and gas commodity price volatility from the Reference Case Portfolio (56%).

9.1.4 Environmental Sustainability

The Environmental Sustainability objective is determined from the stochastic analysis and is measured in two ways, CO_2 intensity (tons of CO_2/kWh) and by CO_2 equivalent emissions (stack emissions) in tons of CO_2e over the 20 year planning period. The latter was built with two suggestions from stakeholders. First CO_2e 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")[70,71] to convert to CO_2

[70] 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.
[71] 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.

equivalence. Secondly, this metric measures total CO_2 tons that go into the atmosphere over the 20-year planning period verses picking a point in time. The development of these measures is described in detail in Section 2.3.2.3 and considers the total CO_2e emissions associated with the annual MWh of generation over 20 years from each technology type in the candidate portfolio.

The preferred portfolio performed very well in the Environmental Sustainability objective, reducing annual CO_2e emissions by more than 19 million tons over the 2023-2042 study period compared to the reference case and saves approximately 8.4 million tons of CO_2e compared to continuing the run F.B. Culley on coal. This portfolio has slightly less CO_2e emissions than the diversified renewables, which puts a similar level of CO_2e into the atmosphere as this portfolio on an annual basis. While the portfolio continues F.B. Culley 3 on natural gas, it is projected to run very little, serving as a low-cost peaking unit, preserving critical capacity needed for long duration weather events.

While not part of the balanced scorecard, by 2035 the preferred portfolio was found to reduce CO_2 emissions in the reference case by approximately 98% compared to the baseline year of 2005. This represents an annual reduction of nearly 9.4 million tons of CO_2 from the baseline of 9.6 million tons of CO_2, with the small remainder driven mostly by the new combustion turbines needed to support this renewable generation portfolio.

9.1.5 Future Affordability (Market Risk Minimization)

The Market Risk Minimization objective is applicable to both energy market risk and capacity market 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 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. Conversely, 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 sales by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be lower than the cost of capacity in the CEI South fleet, meaning the portfolio is overbuilt. In either case, heavy reliance on market sales could lead to inflated valuation of a portfolio.

The preferred portfolio performed relatively well in terms of energy market risk minimization, averaging 26% energy purchases as a percentage of generation. This figure is among the best of the 10 candidate portfolios. The best portfolio was the Reference Case (12%). The preferred portfolio near the middle in terms of energy sales with a figure of 19% as a percentage of generation much less than the reference case portfolio at 33%, which performed worse than all other portfolios in this category. While, the preferred portfolio has some energy market risk, both in terms of its own measure and relative to the measures of other candidate portfolios, it has the greatest level of dispatchable resources among portfolios considered at 941 MWs, which can be turned on at peak periods to protect from extremely high priced energy.

The preferred portfolio performed very well in terms of capacity market risk minimization, demonstrating a figure of only 0.6% capacity market purchases as a percentage of peak load. This figure is the lowest of the 10 candidate portfolios, slightly better than the Business as Usual portfolio with 0.9% capacity market purchases. The conversion of F.B. Culley 3 reduces the need for significant levels of capacity purchases throughout the planning horizon, which is important since MISO is still projecting capacity shortages in the future. In the 2022/2023 planning year, MISO capacity price cleared at the maximum level, CONE. MISO continues to update market rules and mechanisms to ensure reliability and resilience of the grid as renewables become a much larger share of the region’s portfolio. Maintaining capacity of F.B. Culley 3 for our customers during this time is an insurance policy to help protect affordability for our customers. While the preferred portfolio’s NPVRR does benefit from capacity market sales at 12% as a percentage of peak load, there is more cost risk to customers from being exposed to capacity purchases

than the benefit it provides in the form of a lower NPVRR over the long term. Since portfolios were built to maintain relatively low capacity market exposure, all portfolios fall in a range from 8-13%.

9.1.6 Other Considerations

9.1.6.1 Future Flexibility

The preferred portfolio provides a low cost off ramp in the future, while eliminating customer exposure to coal fired generation. As MISO continues to update market rules and mechanisms, it is clear that some level of dispatchable resources will be necessary to maintain the reliability of the grid in the long-term. Today, there are no long duration (multiple day) battery storage options that are commercially viable. When such resources, or other new technologies, become cost competitive, CEI South can reevaluate this option in future IRPs. Until such time, CEI South customers will benefit from converting F.B. Culley 3 to natural gas.

9.1.6.2 Resiliency

The preferred portfolio offers CEI South customers with additional renewable energy but also provides dispatchable resources that will be able to back up these resources when needed to ensure reliability. The combustion turbines that will be installed at A.B. Brown will provide quick start/fast ramping capability when needed, and the natural gas fired Culley 3 will be available when needed for long duration peaking support, both with firm gas supply and access to multiple regions. These dispatchable resources are important to ensure reliability at all times, particularly when intermittent resources experience long duration droughts, periods of sustained high demand, or potential future winter weather events. CT's can also be black started, offering an additional degree of increased resiliency and operational flexibility.

9.1.6.3 Maintains Interconnection

The preferred portfolio maintains the existing 270 MW interconnection rights at F.B. Culley 3, protecting 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 of interconnection requests is exhausting available transmission capacity. Lastly, maintaining the existing interconnection preserves the rights for replacement resources in future IRPs.

9.1.6.4 Reliability

The preferred portfolio was among the best portfolios in meeting MISO's Planning Reserve margin requirement in all seasons when tested in a full range of probabilistic load environments.

Reliability can be measured in different ways, but one common metric is whether the portfolio experiences unserved energy. The preferred portfolio was dispatched in the Encompass model using Reference Case inputs as well as the inputs from the four alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load and capital costs. In each of these deterministic dispatch runs, the preferred portfolio was not found to have a significant number of hours of unserved energy. Accordingly, the preferred portfolio was found to provide reliable service in meeting CEI South's expected load requirements over the 20-year study period. It contains two highly dispatchable combustion turbines (460 MW) to support a high penetration of renewables, ensuring reliability and provide a hedge against both the energy and capacity markets. These resources have quick start, fast ramping capability that can be turned on within 10 minutes. The portfolio also has 180 MWs of older CTs that can be turned on within 30 minutes, one of which provides blackstart capability. Maintaining F.B. Culley 3 as a converted gas peaking unit compliments CEI South's fleet of CTs as a further hedge against high energy prices. These thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind, allowing for a smooth transition into a renewables future locally and regionally as the

MISO system adapts to higher levels of renewables across the system. The portfolio maintains enough dispatchable generation to meet load demand when solar is not contributing to meet peak need and the wind may not be blowing. It was designed to meet the needs of CEI South customers in the worst weeks of each season, consistent with MISO's guidance.

As described in section 6.4.3 CEI south worked with 1898 to conduct analysis and review reliability for several alternative paths for F.B. Culley, including conversion to gas, retirement, and replacement with battery storage. This near-term assessment reviewed thermal loadings, voltage, VAR support, and transfer capability. No mitigations were identified in the F.B. Culley Conversion case, while upgrades were needed should F.B. Culley be retired or replaced with battery storage.

9.1.6.5 Operational Flexibility

The preferred portfolio includes a significant amount of Variable Energy Resources ("VER") (wind and solar) balanced by two 230 MW natural gas combustion turbines. The CT units 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 CTs perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Given the level of VER in the preferred portfolio (approximately 800 MW of wind and 1,000 MW of solar) together with the fast-ramping capabilities of the CT's, this portfolio is expected to meet all operational flexibility requirements.

Natural gas peaking CTs respond quickly to changing operational requirements, since there is no water to heat on a percentage of capacity per minute basis (as compared to a combined cycle unit). CTs are simple to operate, requiring few staff and resources to run properly and to maintain (typically under a long-term service agreement or LTSA) and

often they can be started remotely. Note that CEI South maintains two 80 gas CTs, which can also be called upon when needed. One of which, includes black start capability, providing operational flexibility.

Given the high volume of intermittent renewable generation in the preferred portfolio CEI South feels it's critical to have an adequate amount of dispatchable generation to meet its obligation to ensure reliable service is provided to CEI South customers throughout the different seasons of the year as well as all 24 hours of the day. 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.

9.1.6.6 Resource Diversity

Resource Diversity is not an explicit objective in the balanced scorecard but is nevertheless an important criterion for a well-balanced portfolio. Resource Diversity allows a portfolio to avoid being dependent on one type of fuel or technology, which can expose the fleet to 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. Resource Diversity also contributes indirectly to the other objectives discussed here, including operational flexibility, future flexibility and reliability. From this point of view, the preferred portfolio is reasonably diverse and well-balanced in terms of resources, with a mix of natural gas CTs, solar and wind resources, energy efficiency, demand response resources and a converted coal unit to natural gas, fed from a different gas pipeline than CTs.

CEI South is exploring the potential to add commercial and industrial demand response resources. 25 MW was included in the preferred portfolio, and CEI South is currently in discussions with a DR aggregator to explore the market potential in the Evansville area. Additionally, CEI South's AMI system now allows for a time based rate. CEI South is

working with Cadmus to help develop 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 that 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.

9.1.6.7 Local Resources

CEI South prefers local resources for both capacity and energy needs. Local resources benefit CEI South customers by reducing cost risk and providing tax base, jobs and grid support for reliability.

Local generation also 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. The chances of incurring these charges increases the further away energy must be delivered. 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.

Investing in local projects help produce tax base and jobs, which directly benefit the communities CEI South serves. Currently, CEI South generates tax revenues for primarily two counties, Posey and Warrick. The preferred portfolio continues to provide opportunities for continued investment in these counties with the potential to also provide tax base from generating resources in Vanderburgh, Gibson and Spencer counties. 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.

Local projects also help keep the system reliable. CEI South's preferred portfolio maintains a good balance between intermittent renewable generation and local, dispatchable generation that provides the system with voltage support and a physical hedge against instances of high market prices. This is particularly important for large, industrial customers that make up nearly half of CEI South load.

9.1.6.8 Stability (Transmission/Distribution)

The Culley Unit 3 conversion to natural gas was used as a base case for various study cases as the conversion to gas was treated as a MW for MW conversion. No issues were identified for this case. The retirement of Culley Unit 3 required the lowest number of transmission system network upgrades for alternate cases. Although the number of network upgrades was lower than other study cases, upgrades to the CEI South system were identified for voltage and reactive power support for this scenario. These upgrades included multiple capacitor banks at different system locations and the conversion of Culley Unit 2 to a 64MVAR synchronous condenser.

The reliance on imports from the MISO market into CEI South's area led to voltage concerns for post contingent conditions due to insufficient reactive reserves. CT's provide mitigation to these issues and can be used for reactive ("VAR") support in the MISO market. The all imports and all renewables cases studied presented voltage issues that could not be mitigated with existing facilities. These issues would require additional network upgrade projects to add reactive power support and could also potentially lead to the need for CEI South to make Reactive Power Payments to the MISO market to receive off-network support to maintain proper reactive power and voltage levels. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed. However, initial

estimates for needed upgrades are estimated to be between $17.5 million (Culley Unit 3 retirement) and $25 million (BESS replacement of Culley 3) to maintain reliability and mitigate the voltage issues. This amount was not included in the NPVRR of this portfolio.[72]

Studies were performed using the latest MISO generation interconnection system models and all renewable resources studied were assumed to be the projects already in the MISO queue and existing in the model. Additional study will be required on the preferred portfolio once specific renewable projects are identified and sited to determine any further impacts on the CEI South transmission and distribution electric system.

9.1.6.9 Economic Development

The preferred portfolio allows CEI South to provide solutions to assist with manufacturers' renewable and sustainable energy goals. Companies are setting these goals leading to a reduction in fossil fuels consistent with their sustainability strategies. If these companies cannot find a solution with their local utility partners, they may procure energy from other sources or make strategic decisions to relocate manufacturing load.

Renewable energy investments are important steps in facilitating the ability to provide CEI South customers with a portion of their energy requirements via renewable energy. With proper oversight and investment strategy renewable energy can be more efficient and cost-effective for many customers as compared to securing their own sources of energy which requires land and/or capital investments.

The communities in CEI South's service territory will benefit to the extent the addition of renewable energy supports growth among CEI South South's large customers or attracts new customers. The creation of additional jobs in the communities CEI South serves has a ripple effect on the local economy. Moreover, renewable energy projects will create construction jobs in the community and provides additional income for landowners, which

[72] These amounts are a subset of total costs discussed in Section 6.4.3

also will benefit the local economy. Ultimately, renewable energy projects support the attraction and retention of large customers.

Although CEI South supports cost effective and reliable renewable energy projects, CEI South must maintain strategic planning in the event large industrial customers locate to SW Indiana and require baseload generation for production. Site selectors and large industrial power users are typically sophisticated and fully understand the requirements to apply, receive approval and execute generation buildout. Comprehensive generation planning inclusive of renewable energy and dispatchable resources must be properly balanced to continue economic growth for our region.

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 this needed 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. CTs also prevent CEI South from entering into Reactive Power Payments through the MISO market, which would impact CEI South customers' bills.

Importantly, 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 to be able to adapt to the potential need for CCGT build out. CEI South aggressively pursues manufacturing opportunities which has 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 opportunity for local residents at the same time raising state revenue and tax base. Additionally, large power users assist all CEI South customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

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.

9.1.7 Fuel Inventory and Procurement Planning

It is impossible to perfectly predict price fluctuations in commodity prices such as coal and natural gas. CEI South uses coal contract strategies intended to even out short-term price fluctuations, such as locking in prices for various overlapping time horizons. Normally these contract renewals are staggered in time to even out short-term price fluctuations. 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 peaking units. It is planned that the future flexible combustion turbines at A.B. Brown and F.B. Culley, when converted, will utilize firm pipeline supply contracts.

SECTION 10
SHORT TERM ACTION PLAN

10.1 DIFFERENCES BETWEEN THE LAST SHORT-TERM ACTION PLAN FROM WHAT TRANSPIRED

CEI South pursued all the items listed in the 2019/2020 IRP short-term action plan.

10.1.1 Generation Transition

Following the conclusion of the 2019/2020 IRP, CEI South began a generation transition plan to replace the majority of its coal fleet with 700-1,000 MW of solar, 300 MWs of wind, and two highly dispatchable natural gas combustion turbines. CEI South pursued this plan, which includes securitization of AB Brown units 1&2 to help customers with affordability, through multiple filings in Cause numbers 45501, 45600, 45754, 45786, 45836, 45839, 45847, 45564, and 45722.

Consistent with the short-term action plan in the 2019/2020 IRP, CEI South received approval in the 45501 Order for two renewable projects – the Posey County Solar Project and Warrick County Solar Project (collectively the "45501 Solar Projects"), which were selected from the 2019 All-Source RFP. Additionally, CEI South received approval in the Commission's June 28, 2022 Order in Cause No. 45564 to construct two CTs.

CEI South has also obtained approval in the Commission's May 4, 2022 Order in Cause No. 45600 to (1) enter into a PPA to purchase energy, capacity, and Renewable Energy Credits ("RECs") from a 185 MWac solar project in Vermillion County, Indiana, over a 15-year term (the "Vermillion County Solar Project"); and (2) enter into a PPA, to purchase energy, capacity, and RECs from a 150 MWac solar project in Knox County, Indiana, over a 20-year term (the "Knox County Solar Project" and collectively the "45600 Solar Projects").

CEI South received approval in the Commission's January 11, 2023 Order in Cause No. 45754 to purchase and acquire, indirectly through a BTA, a solar facility in Pike County, Indiana, that will have an aggregate nameplate capacity of approximately 130 MWac (the

"Pike County Solar Project"). In addition, CEI South has requested a CPCN in Cause No. 45836 to purchase and acquire, indirectly through a BTA, a wind facility in MISO's Central Region, and CEI south has requested a CPCN in Cause No. 45847, to amend the Posey County Solar Project. Both proceeds are pending as of the date of submitting this IRP.

10.1.2 DSM

The 2019 IRP did support continued energy efficiency programs designed to save 1.25% of eligible retail sales. CEI South proposed the 2021-2023 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on February 3, 2021 in Cause No. 45387. Consistent with the 2019 IRP, the framework for the 2021-2023 filed plan was modeled at a savings level of 1.3% of retail sales adjusted for an opt-out rate of 77% eligible load.

10.1.3 Solar Projects

The 50 MW Troy Solar Project, approved in Cause No. 45086 was completed and began putting power onto the grid on January 22, 2022. This project, which is located in Troy, IN was the first large scale solar project for CEI South. Learnings from this project helped CEI South in selection of proceeding solar projects in the generation transition plan. Additionally, CEI South, in partnership with Scannell and DOE installed rooftop solar comprising about 120 kW that entered commercial operation in December 2022. As with pilots that proceeded this project (Oak Hill and Volkman) this project helped CEI South understand what is needed to design, construct, and operate a facility on a leased rooftop.

10.1.4 Wind Project

CEI South is currently negotiating with a developer to secure a 200 MW wind generation facility, located in MISO Zone 4, under a Build Transfer Agreement. As of the date of submission of this IRP, the CPCN is still pending before the Commission in 45836.

10.1.5 F.B. Culley 2

In the last 2019/2020 IRP, CEI South CEI planned to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) by the end of 2023. The Coal Combustion Residuals Part A Rule has provided CenterPoint Indiana South with a path to continue operating F.B. Culley 2 through 2025 by constructing a CCR compliant pond to dispose of bottom ash. The class 5 cost estimate to construct the pond to handle bottom ash from F.B. Culley 2 and maintain the capacity accreditation from F.B. Culley 2 to meet the MISO PRMR was estimated at the time to be $6 million with a current construction cost estimate of $8.9 million. This was lower cost than bids the Company received to purchase market capacity to meet the projected shortfall. As such CEI South plans to continue to operate this unit into 2025 to help shield customers from high capacity cost, which cleared at MISO's maximum price, CONE, in the 2022/2023 planning period.

10.1.6 Environmental Permits for ELG/CCR

The bottom ash system at F.B. Culley Unit 3 was converted to a dry system in the Fall of 2020. Work has also been completed to convert the FGD system to zero liquid discharge technology. These two technologies make Culley Unit 3 fully compliant with the ELG rule and the NPDES permit requirements for Culley 3. This work was essential to remain in compliance with ELG/NPDES requirement to cease the discharge of Unit 3 bottom ash by December 31, 2020 and a requirement to meet effluent limitations for FGD wastewater by December 31, 2023. The ZLD technology, along with construction of a new lined pond, also facilitated the continued use of the East Ash Pond, which was necessary for continued operation of Culley 3 beyond April 11, 2021 under the CCR Part A rule. These investments were necessary in order for Culley 3 to continue operations.

The West Ash Pond at F.B. Culley completed closure in December 2020. The closure design includes the construction of a lined contact storm water pond, which receives contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure later this year. Plans are currently underway for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

10.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

The short-term action plan describes the early steps to pursue the preferred portfolio, consistent with the objectives and risk perspectives listed in Section 2.3. Progress on the items listed below will be tracked and reported on in the next IRP. IRP estimates of each piece of the plan listed below can be found in Confidential Attachment 8.2 EnCompass Input Model Files. Individual cost estimates can also be found in Section 6 Resource Options.

10.2.1 Procurement of Supply Side Resources

As described above, the preferred portfolio included conversion of F.B. Culley 3 to natural gas by 2027, adding an additional 200 MWs of solar by 2030, and an additional 200 MWs of wind by 2030. Additionally, it calls for the expansion of demand response programs where possible in the near and long term, with engagment from a DR aggregator to help understand and execute on potential commercial and industrial programs and a pilot to better understand potential of a time based rate. CEI South must continue to plan, as some portions are more certain than others.

CEI South plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) by 2025, and CEI South's contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. CEI South has acquired capacity in the 2023/2024 planning season and is working to secure needed capacity for the 2024/2025 planning year to help meet MISO's planning reserve margin requirement until the two combustion turbines come online, along with solar and wind resources identified in the 2019/2020 IRP. As CEI South plans to convert F.B. Culley 3 to natural gas by 2027, the company will also work to acquire renewable generation to be in place by 2030 to meet CEI South's customers

energy and capacity needs. This equates to approximately 200 MWs of installed capacity from solar generation and 200 MWs of installed capacity from wind generation.

Given fundamental changes in the market, renewables projects now require much longer lead times than in previous IRP cycles. There will not be time to wait for the next IRP to begin pursuing suitable projects to meet the needs of CEI South customers by 2030. To fill this need, CEI South plans to pursue attractive projects from its 2022 All-Source RFP consistent with the findings in the 2022/2023 IRP, to the extent that they are still available. It is likely that CEI South will go out for another RFP over the next year to identify other projects. There is high demand for these projects in Indiana as other utilities are also working through their own generation transitions. Affordable pricing will be important.

10.2.2 DSM

CEI South has filed to extend it's 2021-2023 filed plan for 2024 electric DSM plan on May, 25, of 2023. The 2025-2027 DSM plan will be filed late 2023 or early 2024 with energy efficiency savings guided by the 2022/2023 IRP process. Once plans are approved by the Commission, the CEI South Oversight Board, including the OUCC, CAC and CEI South, will oversee the implementation of energy efficiency programs.

10.2.3 Solar Projects

CEI South plans to acquire a 191 MW solar project located in Posey County, Indiana ("Posey Solar"). The acquisition is contingent on IURC review and approval under Cause 45847. The Posey Solar project is expected to be placed in service in the first quarter of 2025.

Also, CEI South plans to acquire a 130 MW solar project located in Pike County, Indiana ("Crosstrack"). The Crosstrack solar project has received IURC approval and is expected to be placed in service in the first quarter of 2025.

In addition, CEI South has entered into three solar purchase power agreements ("PPA").

The first is a 100 MW 25-year PPA located in Warrick County, Indiana (“Rustic Hills II”). The PPA is contingent on IURC review and approval under Cause 45839. The Rustic Hills II solar project is expected to be placed in service in the second quarter of 2025.

The second is a 185 MW 15-year PPA located in Vermillion County, Indiana (“Vermillion Rise”). The PPA is contingent on IURC review and approval under Cause 45839. The Vermillion Rise solar project is expected to be placed in service in the second quarter of 2025.

And the third is a 150 MW 20-year PPA located in Knox County, Indiana (“Wheatland”). The Wheatland solar project has received IURC approval and is expected to be placed in service in the third quarter of 2024.

For the future 200 MW of solar generation in the preferred portfolio, CEI South will solicit proposals through a Request for Proposal (“RFP”) process, evaluate proposals using quantitative and qualitative information, and select a solar project(s) to be to be brought forth to the IURC for approval in the CPCN process.

10.2.4 Wind Projects

CEI South plans to acquire a 200 MW wind project located in MISO Zone 4 (“Wind Project”). CEI South is currently in negotiation to finalize a Build Transfer Agreement “BTA”) and is contingent on IURC review and approval under Cause 45836. The Wind Project is expected to be placed in service 2025 – contingent on MISO interconnection study results timing.

CEI South will also solicit proposals for wind projects through within the RFP process, evaluate proposals using quantitative and qualitative information, and select a 200 MW wind project to be brought forth to the IURC for approval in the CPCN process. The remaining 400 MW of wind generation will be reevaluated in the next IRP.

10.2.5 Conversion of FB Culley 3

CEI South will seek approval from the Commission to convert F.B. Culley 3 to natural gas by 2027, consistent with the preferred portfolio. CEI South worked with 1898 to study the design conversion of F.B. Culley 3 from coal to natural gas firing to provide cost estimates consistent with AACE Class IV estimates. These planning estimates need to be refined. CEI South plans to work with boiler equipment manufacturers, consulting engineers, and construction companies to provide construction level estimates and schedules. Refining the planning typically takes 36 months to complete preliminary engineering, material procurement, contract negotiations and execution, fabrication, installation and commissioning. CEI South will work with nearby pipelines for a firm service contract to supply the plant with natural gas. Converting FB Culley 3 to natural gas may trigger air permitting modifications. CEI South will work our consultants and IDEM to determine the appropriate permitting requirements.

10.2.6 Combustion Turbines

CEI South continues to work towards commercial operation of the combustion turbines approved in Cause No. 45564. The project kickoff commenced in December 2022, and CEI South provided the Commission with Notice-to-Proceed following FERC approval of the pipeline that will supply the plant. CEI South continues to work closely with the EPC to keep costs at budgeted levels. Planned Initial Operations remain as scheduled for April 2025, with Planned Substantial Completion for May 2025, ahead of the 2025/2026 MISO planning year. The project is expected to provide approximately 460 MWs of capacity and has quick start, fast ramping capability to support renewable generation.

10.2.7 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.

10.2.8 Continuous Improvement

CEI South takes continuous improvement seriously and works to ensure that improvement opportunities are evaluated and where appropriate implemented. This is done in several ways. First, CEI South participates in the Director's report process and listens to critiques of its IRPs from multiple stakeholders. Second, CEI South always conducts post IRP discussions with internal team members, as well as outside consultants to determine what can be done better in the next IRP. Third, CEI South participates in stakeholder meetings of other Indiana utilities and follows stakeholder feedback in those processes. Fourth, CEI South collects information on IRPs through news articles, conferences and Indiana's annual Contemporary Issues meeting. Finally, improvement opportunities come directly through the stakeholder process with formal and informal meetings, as they did throughout this IRP.

CEI South listened to concerns of stakeholders around the black box nature of Aurora modeling software and took action to evaluate alternatives. Encompass was recommended by Citizens Action Coalition as a tool that provides more transparency, allowing for better participation throughout the process. CEI South agreed with stakeholders that EnCompass could help improve the collaborative process. Additionally, CEI South also introduced tech-to-tech calls between formal public stakeholder meetings and shared draft modeling results throughout the process, seeking feedback along the way. This process, which was suggested by stakeholders, helped to provide a forum for more meaningful, consistent dialogue. CEI South benefited from these conversations, which helped to clarify differences of opinion and concerns in a timely manner. Ultimately, the process was strengthened. CEI South worked hard to be transparent throughout.

10.3 Implementation Schedule for the Preferred Resource Portfolio

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

Figure 10-1 – Implementation Schedule

Year	Quarter	Activity
2023	Q2	File for 2021-2023 DSM Extention and submit the 2022/2023 IRP
	Q3	
	Q4	CEI South Rate Case to include request for TOU pilot and proposed updates to DR tariffs
2024	Q1	File for 2025-2027 DSM Plan
	Q2	Issue Renewable RFP for renewable project's indicative pricing
	Q3	File CPCN for Culley 3 NG Conversion
	Q4	Begin 2025 IRP
2025	Q1	
	Q2	File Renewable CPCN(s)[73]
	Q3	Culley 3 NG Conversion CPCN Order
	Q4	File the 2025 IRP

[73] Timing subject to change depending on availability of suitable resources

SECTION 11
TECHNICAL APPENDIX

11.1 CUSTOMER ENERGY NEEDS APPENDIX

11.1.1 Forecast Inputs

11.1.1.1 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.

11.1.1.2 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.

11.1.1.3 Weather Data

Historical and normal HDD and 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 s 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 0.2% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.2% over the forecast period while CDD increased 0.5% per year through 2039. Figure 11.1 and Figure 11.2 show historical and forecasted monthly HDD and CDD.

Figure 11.1 – Heating Degree Days

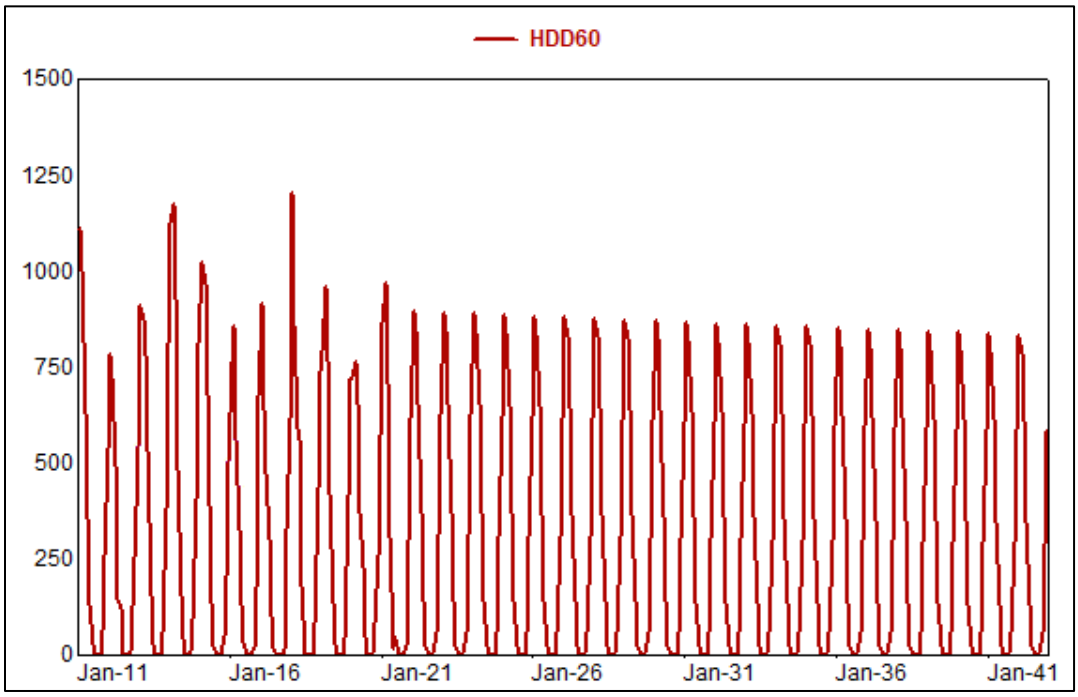
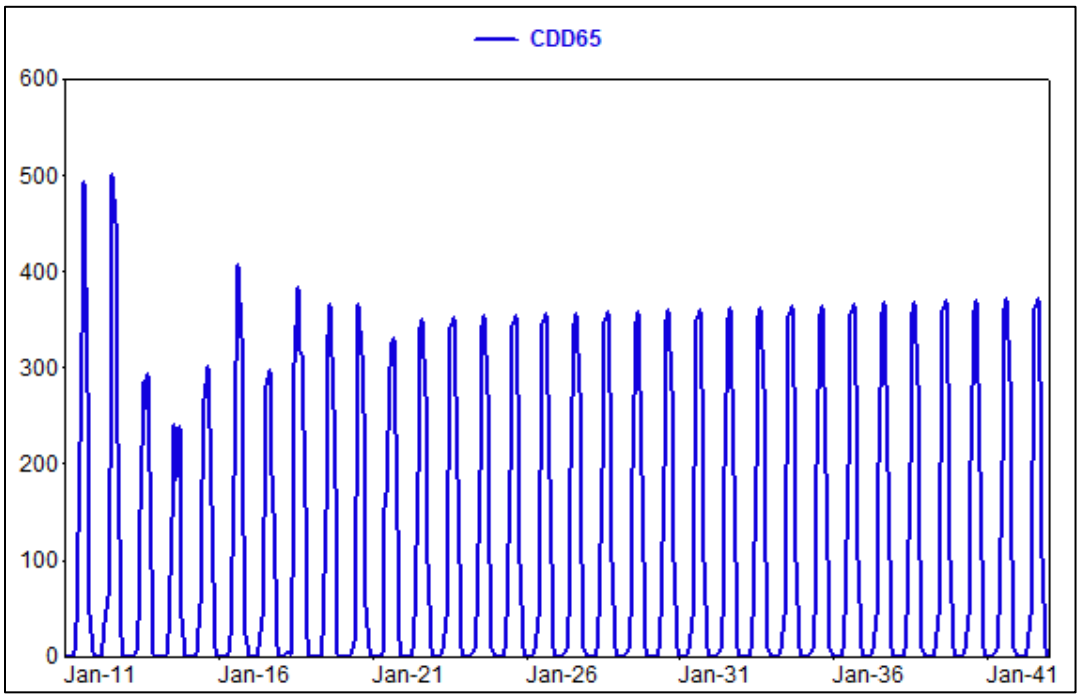


Figure 11.2 – Cooling Degree Days



11.1.1.4 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.

11.1.2 Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE modeling framework. In addition to annually updating efficiency and saturations 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 consensus of EIA and Bloomberg's forecast of vehicle adoption. The result is a 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. CEI South forecasters 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.

11.1.3 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 figurers to IRP forecasts from 2013-2022.

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[74] and forecasted values for:

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

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

Figure 11.3– Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	2016 Total Demand Forecast (MW)	2019 Total Demand Forecast (MW)	WN Total Demand (MW)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	1,115	1,156				1,144	2.6%	-1.0%			
2014	1,107	1,165				1,133	2.3%	-2.8%			
2015	1,100	1,164	1,155			1,113	1.1%	-4.6%	-3.8%		
2016	1,092	1,160	1,156			1,087	-0.5%	-6.7%	-6.3%		
2017	1,094	1,151	1,113	1,082		1,038	-5.4%	-11.0%	-7.2%	-4.3%	
2018	1,093	1,145	1,109	1,086		1,006	-8.6%	-13.8%	-10.2%	-7.9%	
2019	1,091	1,139	1,106	1,085	1,078	1,036	-5.3%	-9.9%	-6.7%	-4.7%	-4.0%
2020	1,084	1,144	1,106	1,088	1,106	984	-10.1%	-16.2%	-12.4%	-10.5%	-12.3%
2021	1,081	1,149	1,106	1,084	1,107	992	-9.0%	-15.8%	-11.5%	-9.2%	-11.5%
2022	1,076	1,155	1,107	1,083	1,129	988	-8.9%	-16.9%	-12.1%	-9.7%	-14.3%
Mean Absolute Error							5.4%	10.9%	9.5%	8.5%	12.9%

Figure 11.4 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	2016 Total Energy IRP Forecast (GWh)	2019 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	5,434	5,807				5,743	5.4%	-1.1%			
2014	5,403	5,803				5,797	6.8%	-0.1%			
2015	5,365	5,772	5,914			5,773	7.1%	0.0%	-2.4%		
2016	5,336	5,725	5,936			5,725	6.8%	0.0%	-3.7%		
2017	5,315	5,657	5,514	5,257		5,073	-4.8%	-11.5%	-8.7%	-3.6%	
2018	5,292	5,590	5,503	5,290		5,139	-3.0%	-8.8%	-7.1%	-2.9%	
2019	5,264	5,520	5,494	5,294	5,178	4,953	-6.3%	-11.5%	-10.9%	-6.9%	
2020	5,218	5,538	5,497	5,319	5,400	4,763	-9.6%	-16.3%	-15.4%	-11.7%	
2021	5,172	5,543	5,492	5,302	5,405	4,893	-5.7%	-13.3%	-12.2%	-8.3%	-10.5%
2022	5,134	5,554	5,494	5,303	5,527	4,716	-8.9%	-17.8%	-16.5%	-12.4%	-17.2%
Mean Absolute Error							6.4%	8.8%	10.6%	9.8%	13.8%

Figure 11.5 – Residential Energy (GWh)

Year	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	2016 Res. IRP Forecast (GWh)	2019 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	1,391	1,419				1,421	2.1%	0.1%			
2014	1,365	1,399				1,412	3.3%	0.9%			
2015	1,332	1,371	1,404			1,444	7.8%	5.1%	2.8%		
2016	1,304	1,340	1,394			1,416	7.9%	5.4%	1.5%		
2017	1,282	1,305	1,383	1,407		1,398	8.3%	6.7%	1.1%	-0.6%	
2018	1,264	1,271	1,377	1,395		1,375	8.1%	7.6%	-0.2%	-1.5%	
2019	1,247	1,237	1,374	1,384	1,393	1,372	9.1%	9.8%	-0.1%	-0.9%	-1.6%
2020	1,218	1,240	1,373	1,375	1,386	1,408	13.4%	11.9%	2.5%	2.3%	1.5%
2021	1,216	1,239	1,370	1,366	1,376	1,414	14.0%	12.4%	3.1%	3.4%	2.7%
2022	1,222	1,244	1,373	1,362	1,378	1,378	11.3%	9.8%	0.4%	1.2%	0.0%
Mean Absolute Error							8.5%	7.7%	1.3%	1.9%	1.4%

Figure 11.6 – Commercial (GS) Energy (GWh)

Year	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	2016 Comm. IRP Forecast (GWh)	2019 Comm. IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	1,304	1,383				1,294	-0.7%	-6.9%			
2014	1,307	1,399				1,312	0.4%	-6.6%			
2015	1,306	1,402	1,304			1,321	1.1%	-6.2%	1.3%		
2016	1,306	1,398	1,320			1,281	-1.9%	-9.1%	-3.0%		
2017	1,309	1,384	1,315	1,315		1,278	-2.4%	-8.3%	-2.9%	-2.9%	
2018	1,311	1,373	1,311	1,324		1,235	-6.1%	-11.1%	-6.1%	-7.2%	
2019	1,312	1,362	1,308	1,326	1,269	1,184	-10.8%	-15.1%	-10.5%	-12.0%	-7.2%
2020	1,308	1,374	1,311	1,325	1,280	1,117	-17.1%	-23.1%	-17.4%	-18.7%	-14.7%
2021	1,319	1,380	1,310	1,321	1,284	1,152	-14.5%	-19.8%	-13.8%	-14.7%	-11.5%
2022	1,332	1,389	1,313	1,322	1,290	1,156	-15.2%	-20.1%	-13.5%	-14.3%	-11.6%
Mean Absolute Error							7.0%	13.3%	9.6%	14.9%	11.5%

Figure 11.7 – Industrial (Large) Energy (GWh)

Year	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	2016 (Large) IRP Forecast (GWh)	2019 (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	2,449	2,693				2,744	10.7%	1.9%			
2014	2,446	2,693				2,786	12.2%	3.3%			
2015	2,445	2,688	2,916			2,722	10.1%	1.2%	-7.1%		
2016	2,447	2,679	2,932			2,722	10.1%	1.6%	-7.7%		
2017	2,446	2,664	2,546	2,211		2,097	-16.7%	-27.1%	-21.4%	-5.5%	
2018	2,440	2,646	2,547	2,252		2,182	-11.9%	-21.3%	-16.7%	-3.2%	
2019	2,430	2,623	2,546	2,270	2,159	2,073	-17.2%	-26.5%	-22.8%	-9.5%	-4.1%
2020	2,419	2,625	2,549	2,312	2,348	1,971	-22.7%	-33.2%	-29.3%	-17.3%	-19.1%
2021	2,417	2,625	2,550	2,317	2,360	2,041	-18.4%	-28.6%	-25.0%	-13.5%	-15.6%
2022	2,410	2,622	2,550	2,322	2,464	1,942	-24.1%	-35.0%	-31.3%	-19.6%	-26.9%
Mean Absolute Error							15.4%	19.8%	22.0%	15.0%	21.3%

11.1.3.1 Actual and Weather Normalized Energy and Demand Levels

Figure 11.8 – Historic Peak Demand

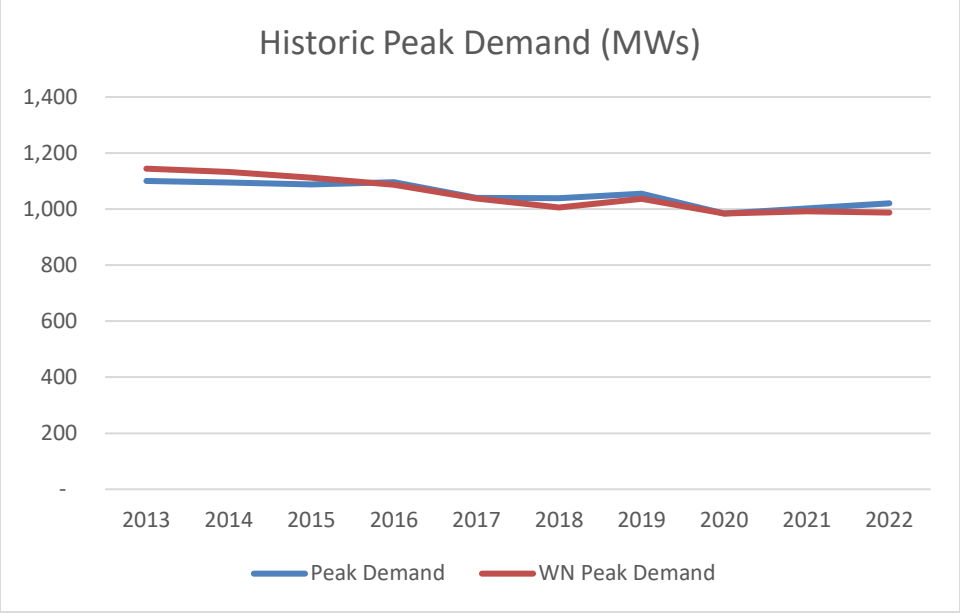
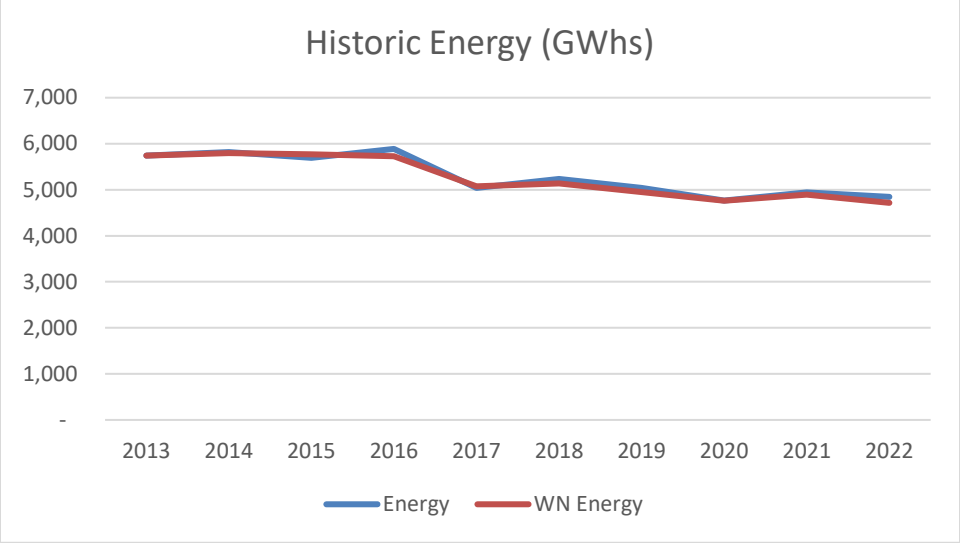


Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

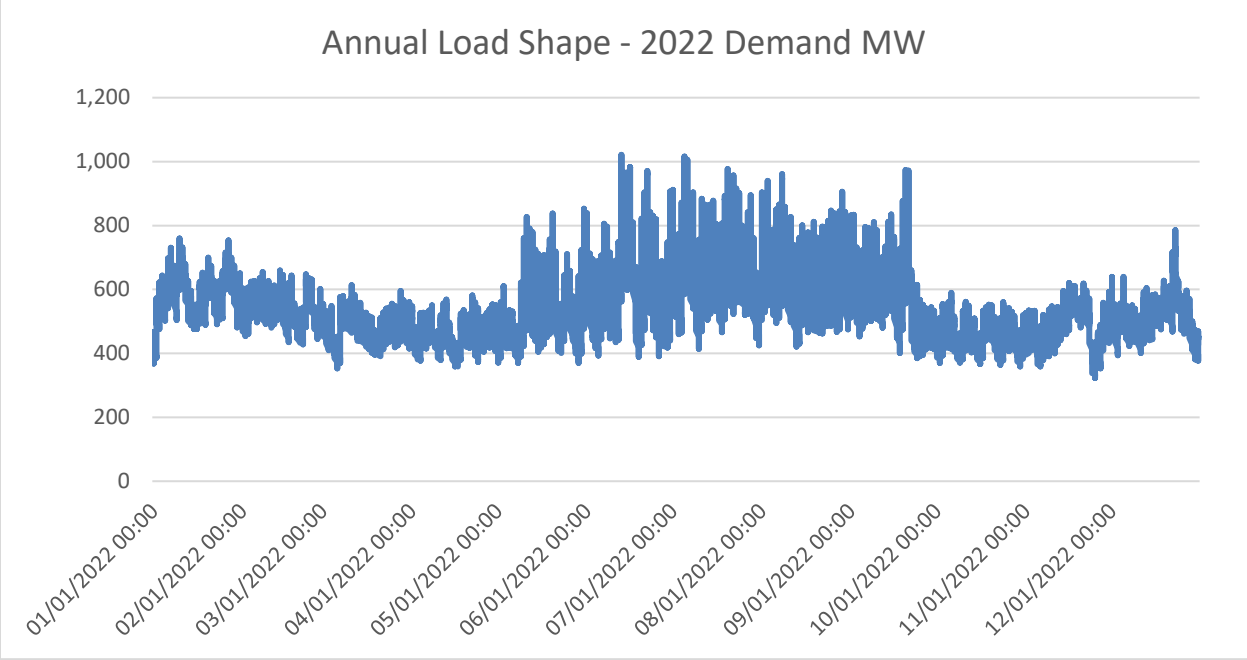


Figure 11.11 – Winter Peak Day

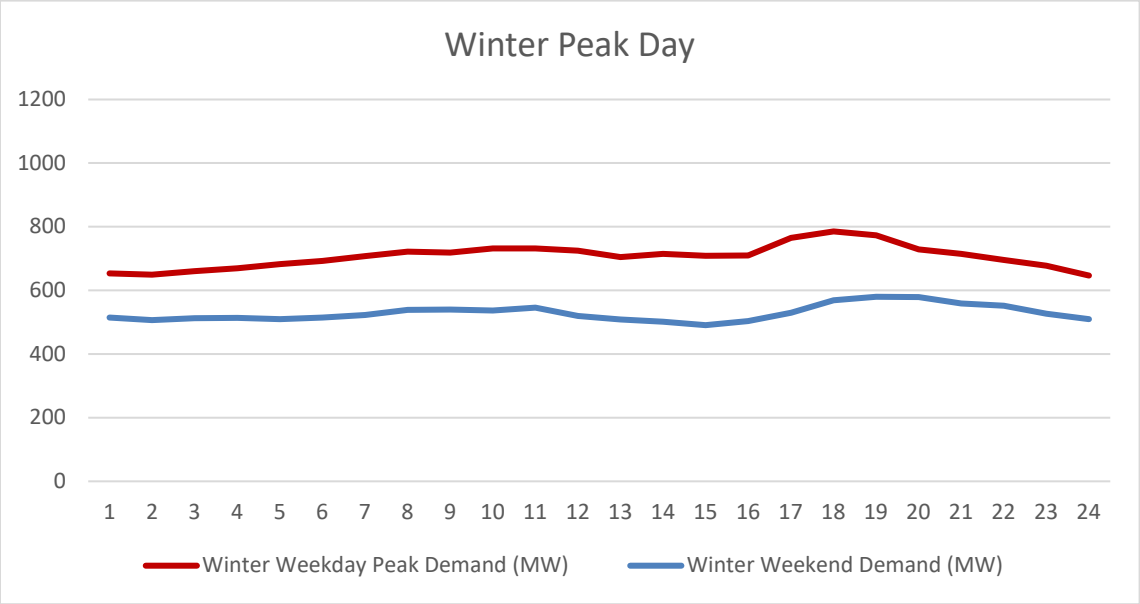


Figure 11.12 – Typical Spring Day

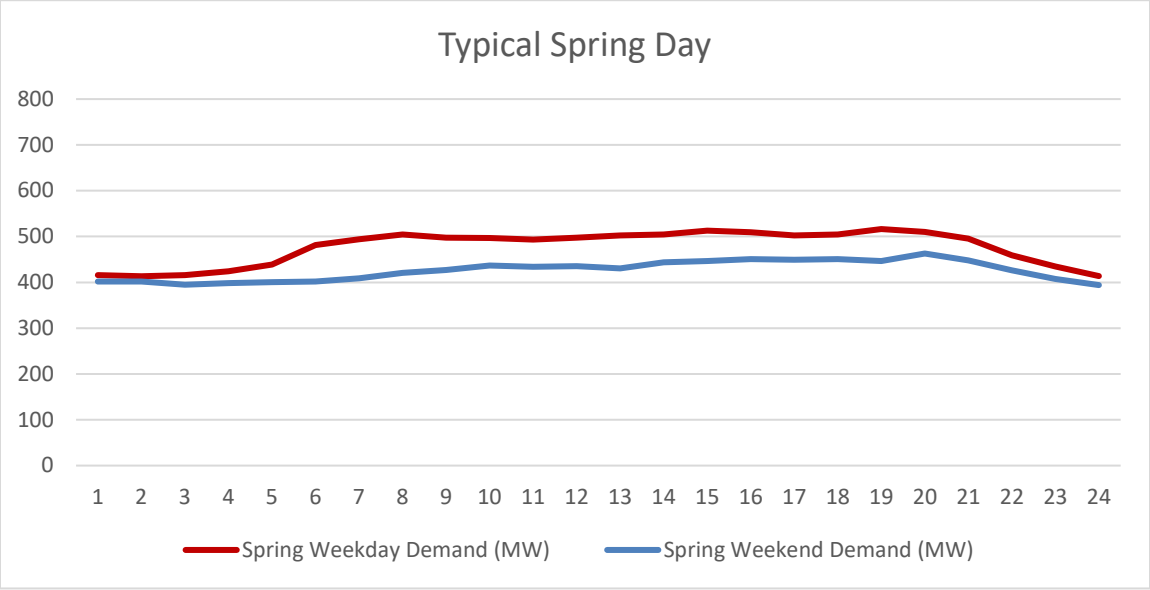


Figure 11.13 – Summer Peak Day

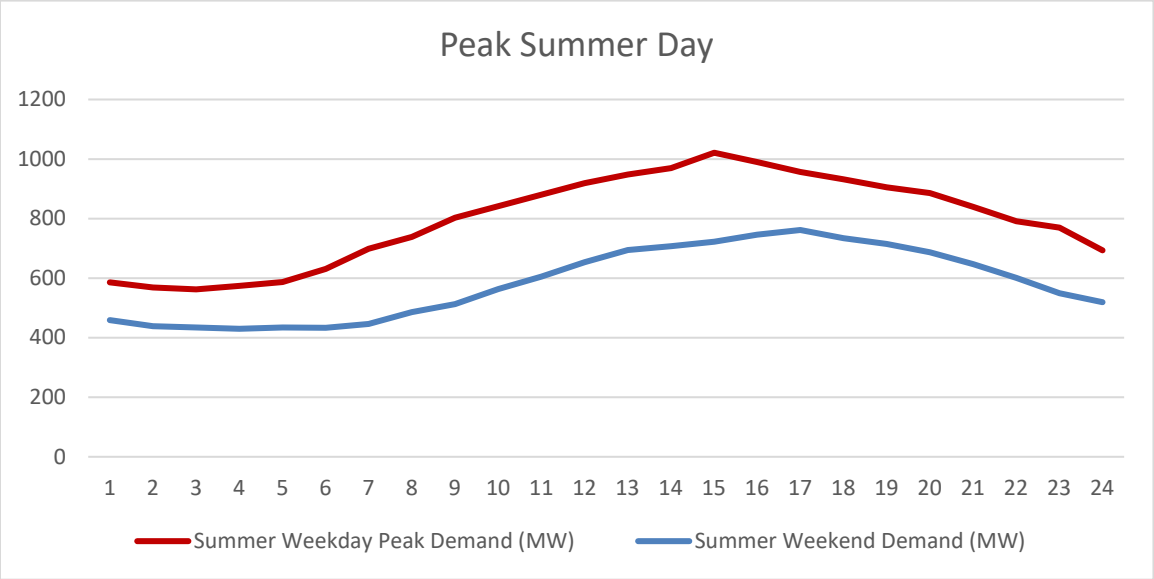


Figure 11.14 – Typical Fall Day

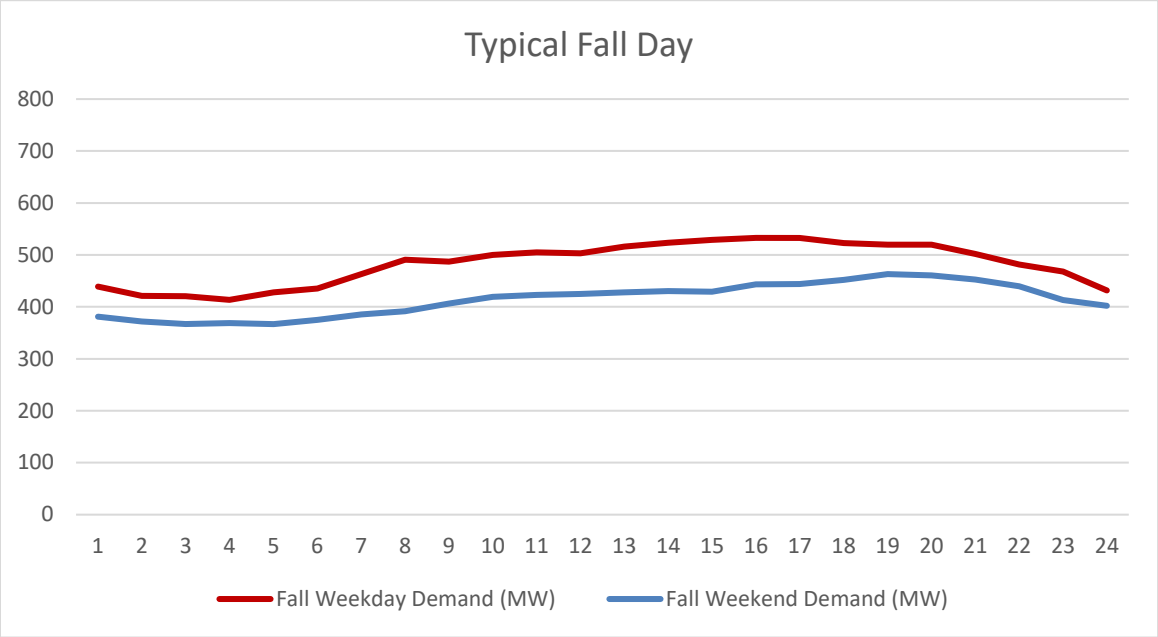


Figure 11.15 – January Load

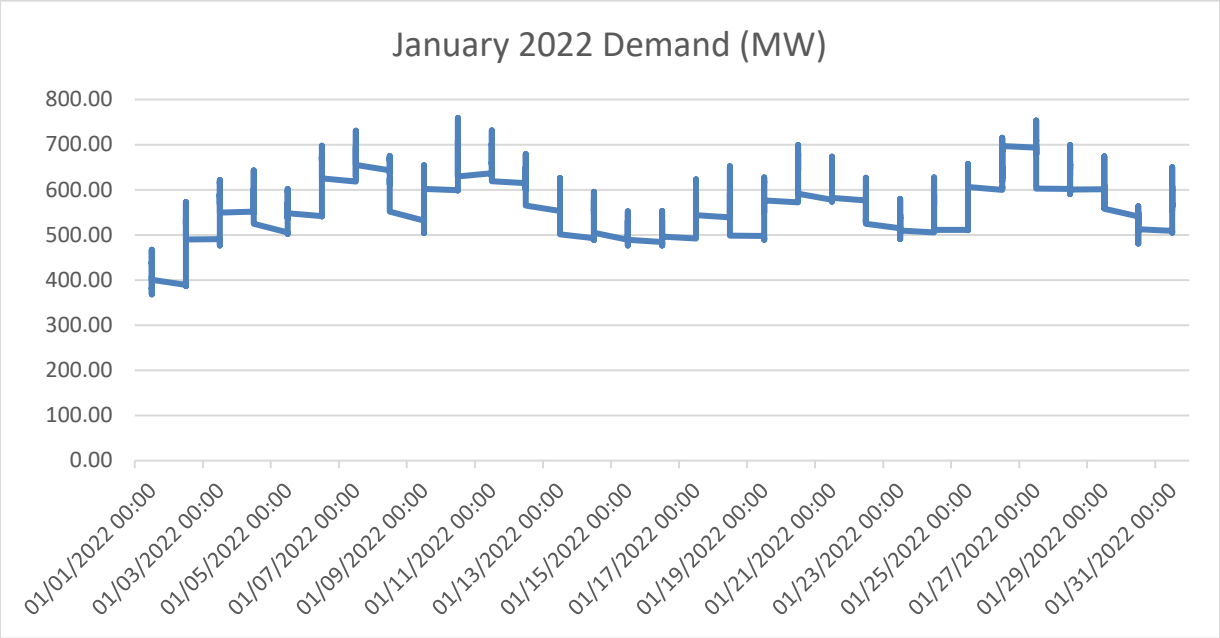


Figure 11.16 – February Load

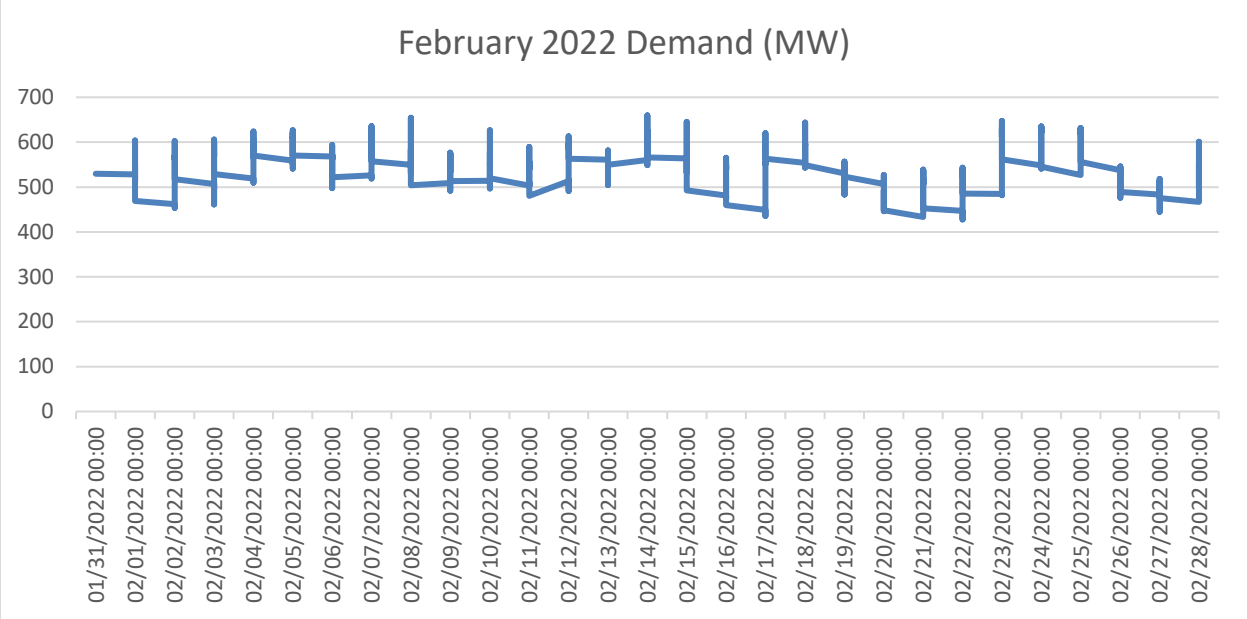


Figure 11.17 – March Load

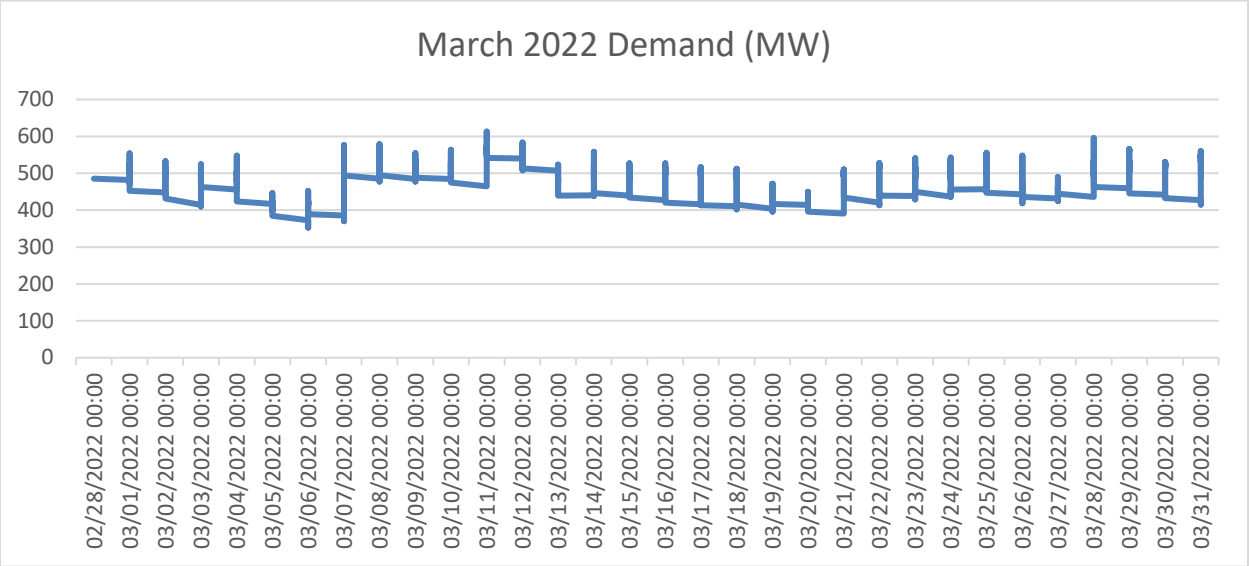


Figure 11.18 – April Load

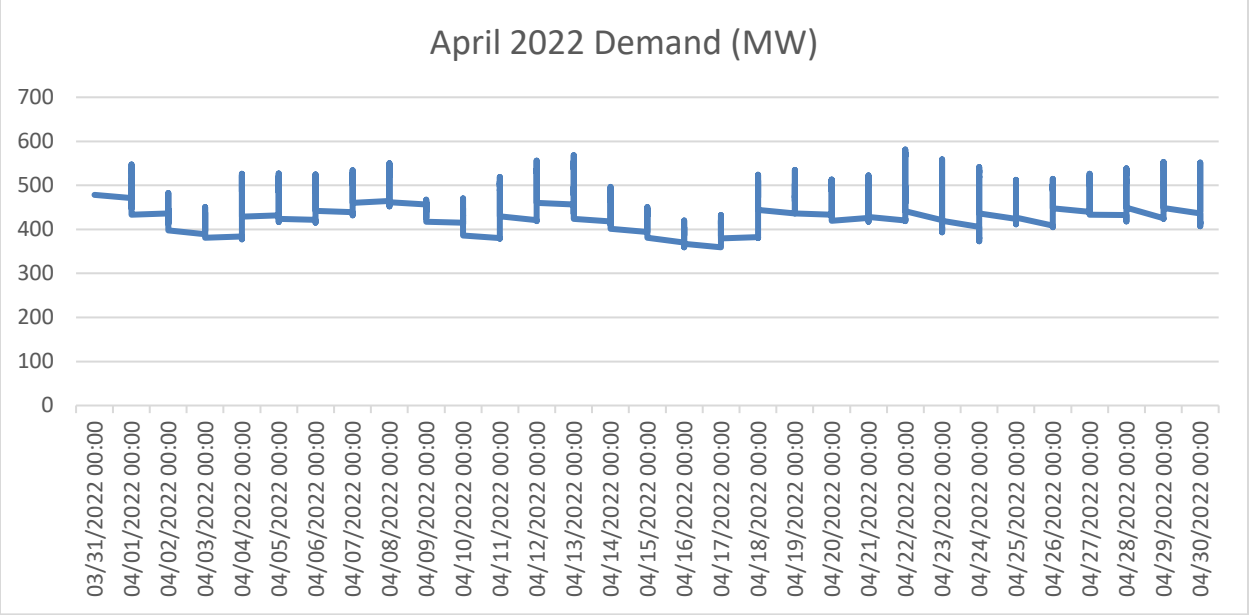


Figure 11.19 – May Load

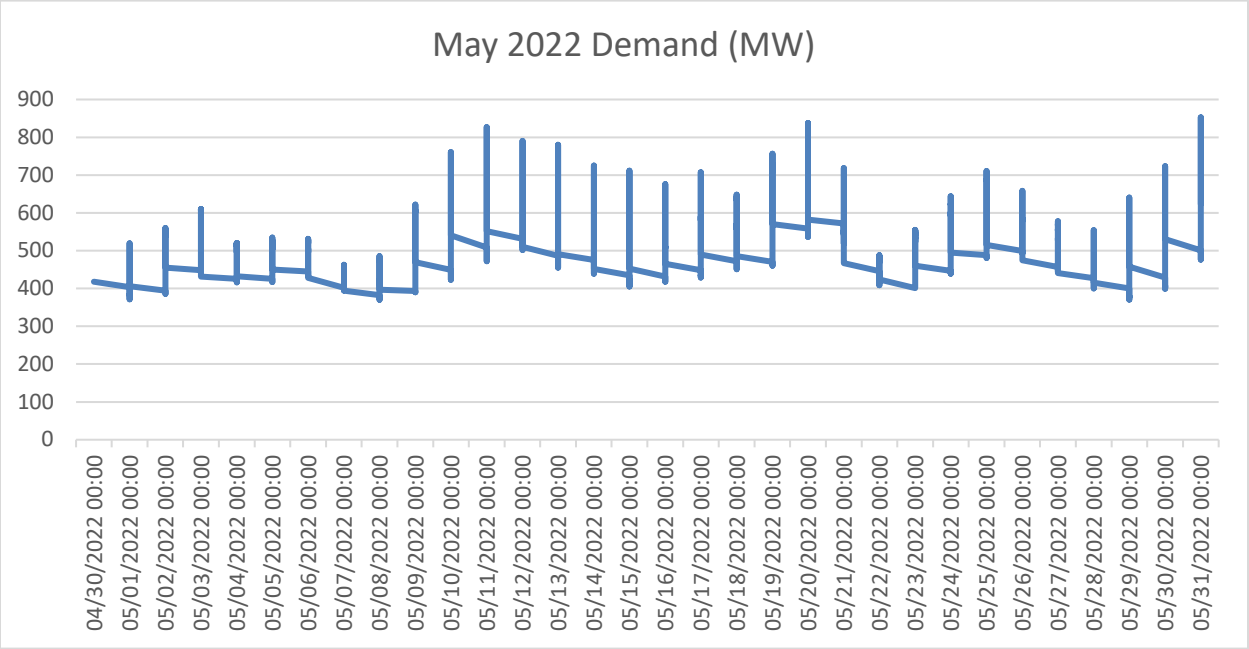


Figure 11.20 – June Load

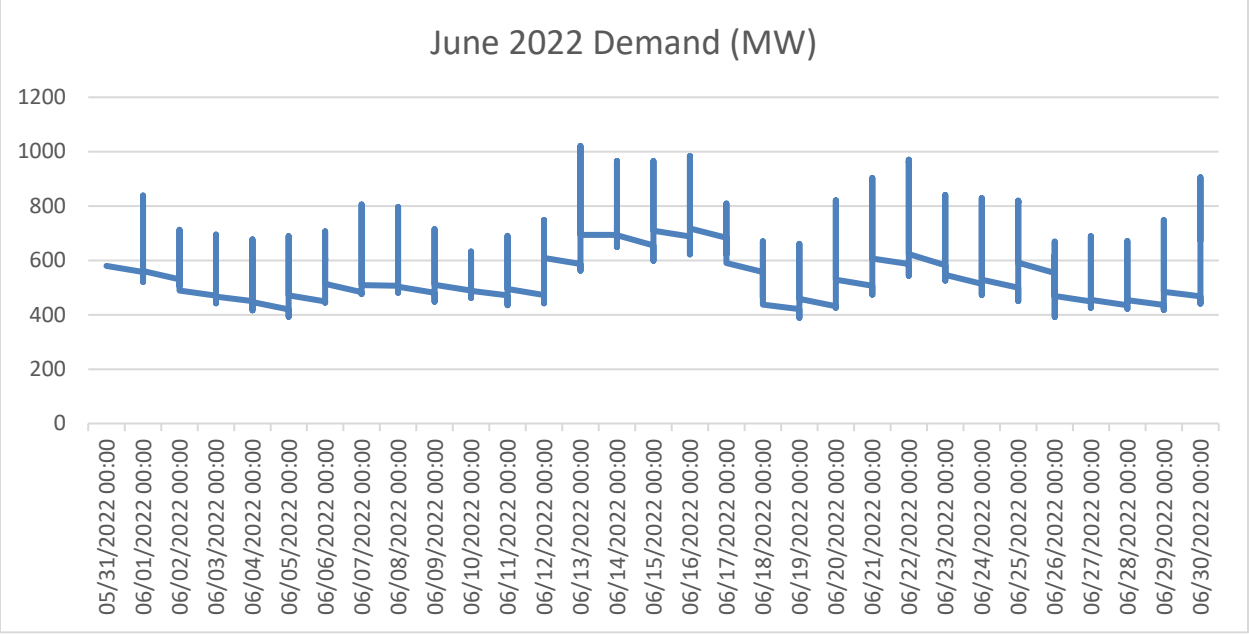


Figure 11.21 – July Load

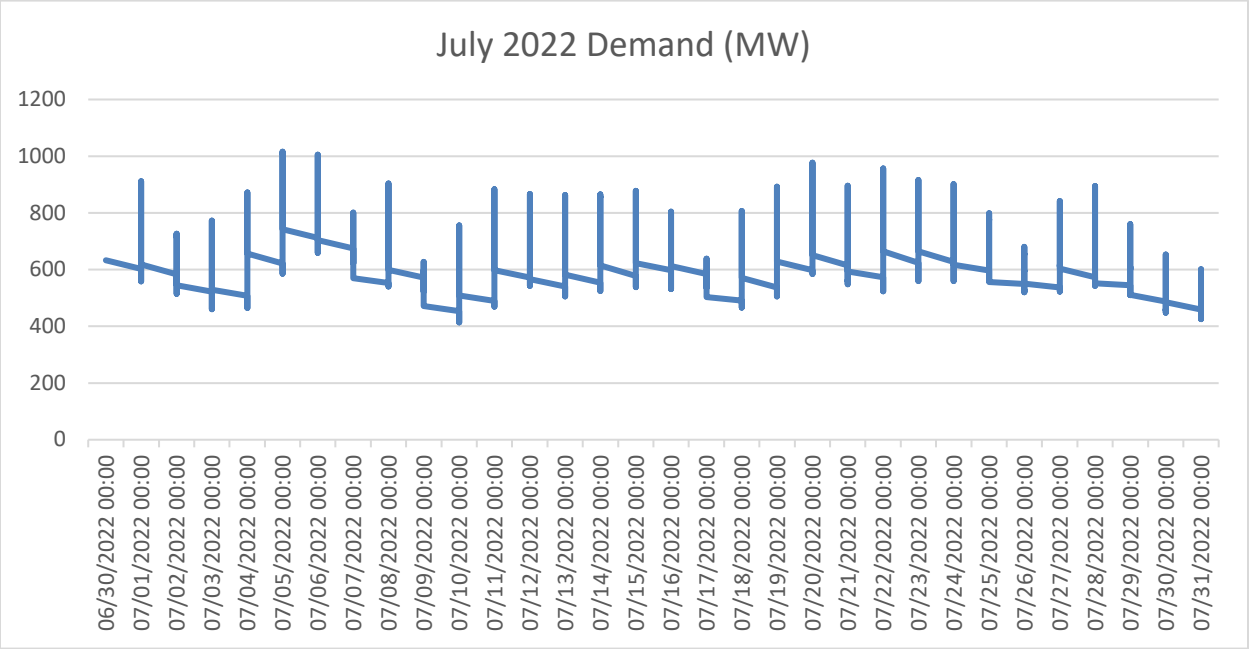


Figure 11.22 – August Load

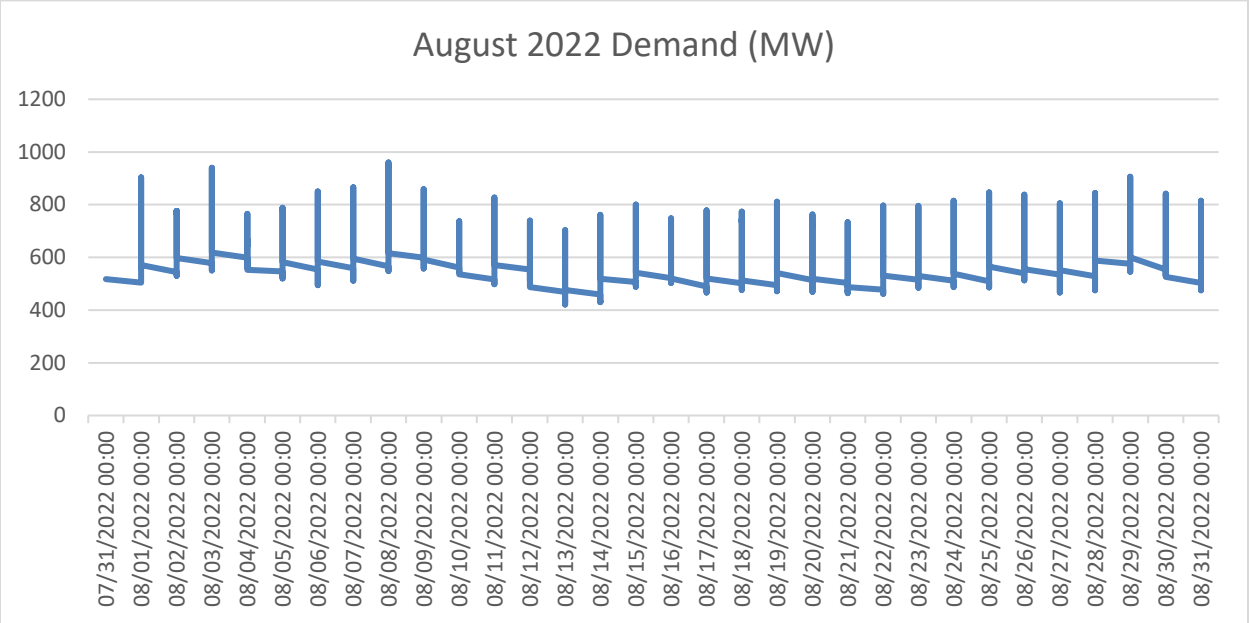


Figure 11.23 – September Load

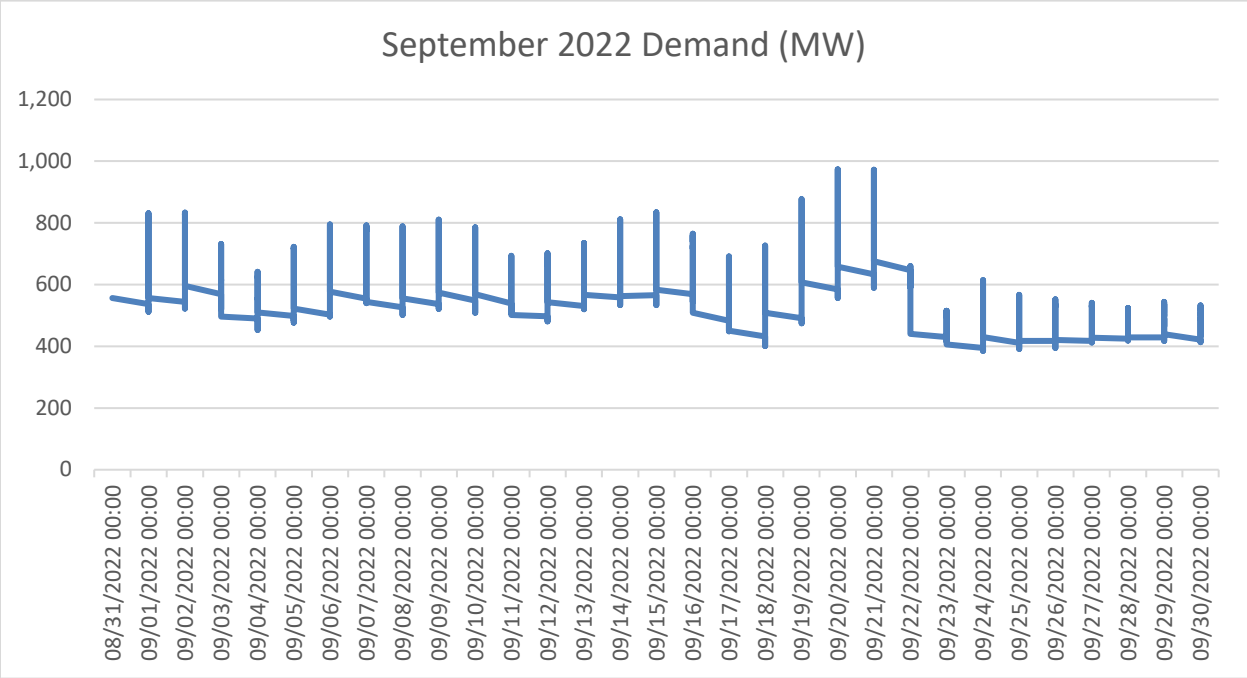


Figure 11.24 – October Load

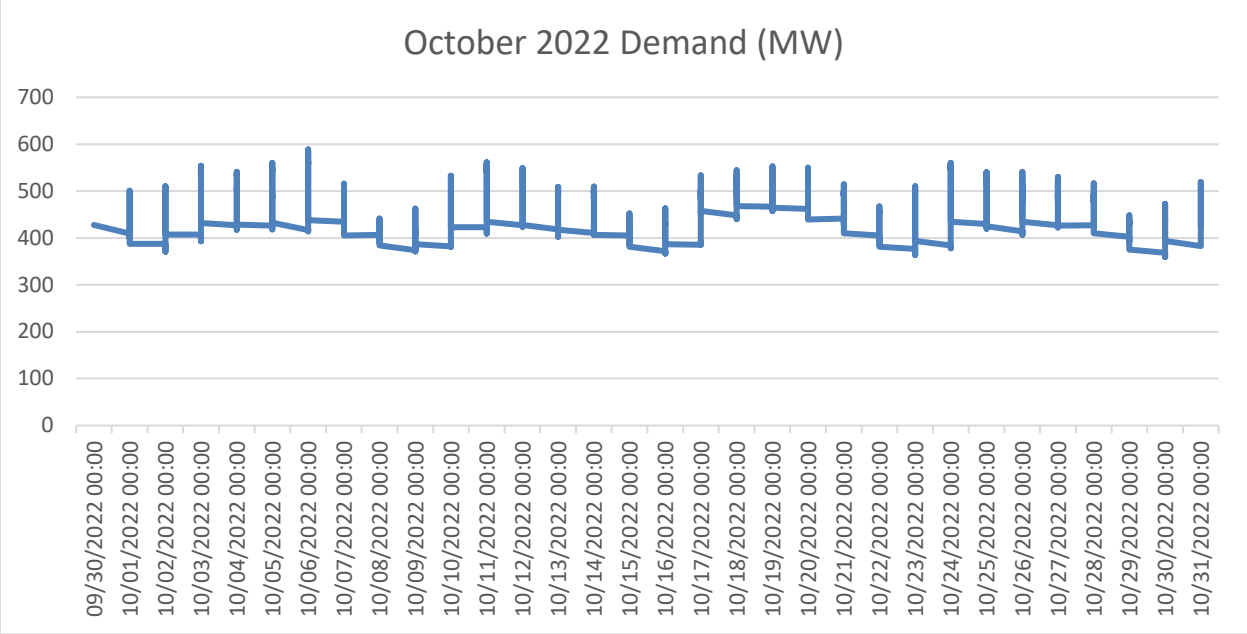


Figure 11.25 – November Load

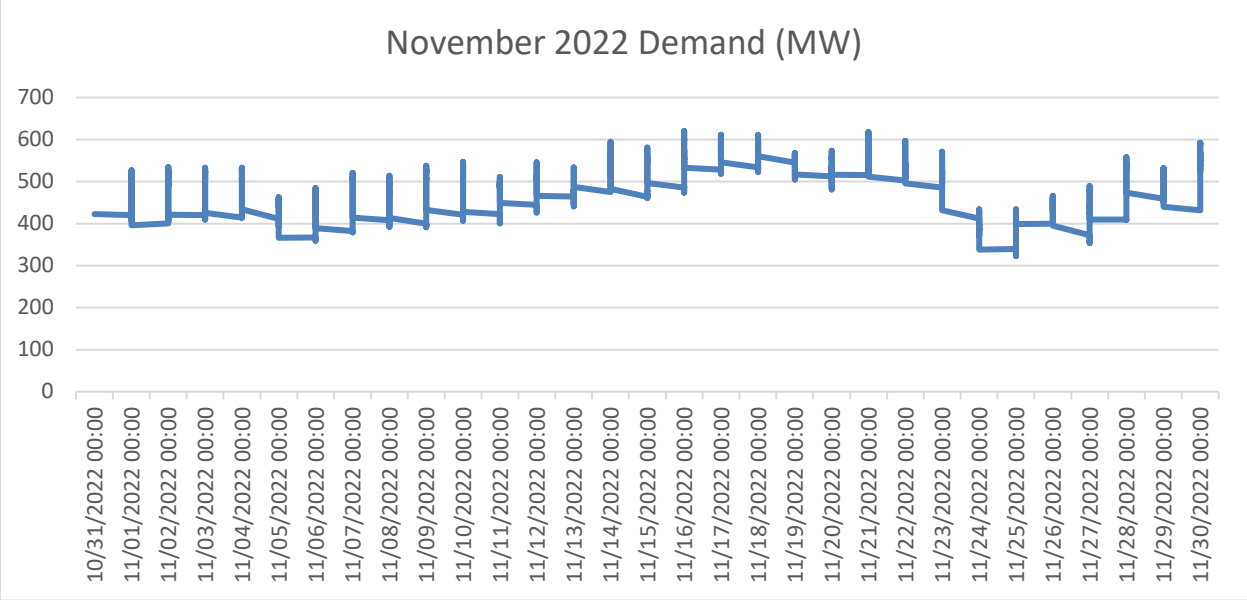
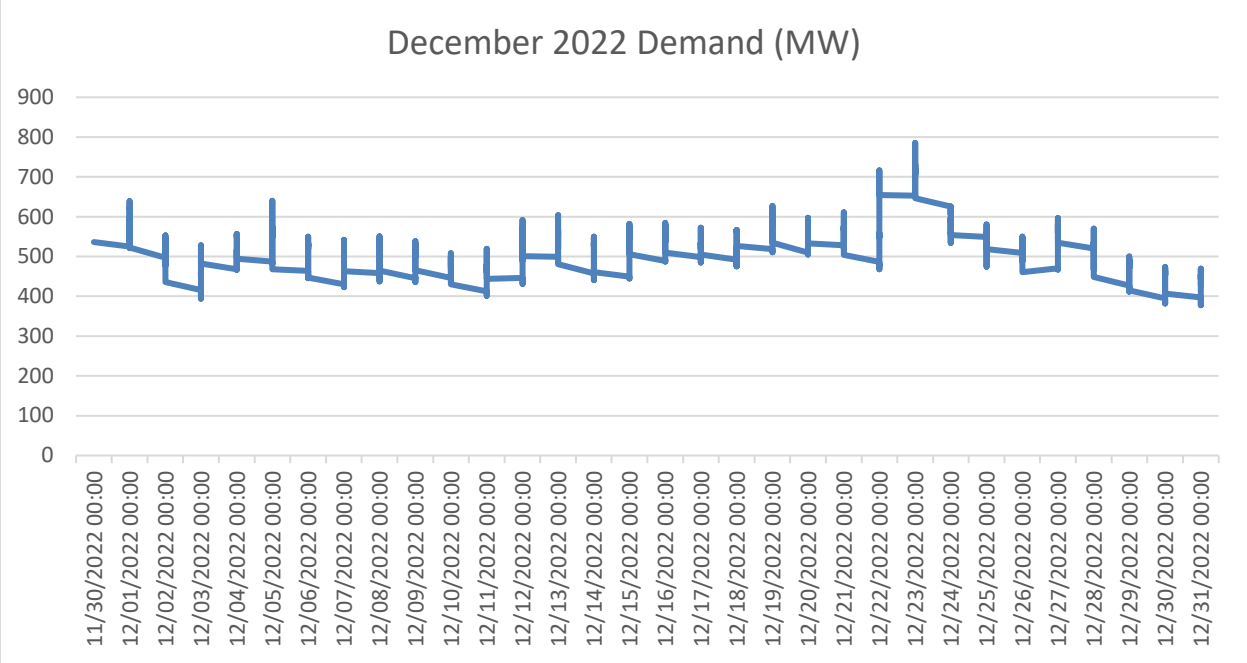


Figure 11.26 – December Load



11.2 ENVIRONMENTAL APPENDIX

11.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed CEI South's allocated annual SO_2 and NOx emission allowances. CEI South's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio. However, the Revised CSAPR Update rule, finalized in March 2021 and effective beginning during the 2021 ozone season, reduced the number of seasonal NOx allowances that are allocated to electric generating units in 12 states. While CEI South has made operational and maintenance adjustments aimed at reducing NOx emissions during ozone season, the allocation reductions have resulted in CEI South having to purchase seasonal allowances from the market to cover the difference. On March 15, 2023, EPA released a pre-publication version of the Ozone Good Neighbor rule, which covers 23 states (an increase from the 12 covered by the Revised CSAPR Update rule) and will further revise the budget for the CSAPR NOx ozone season trading program. The rule also contains a "backstop" daily NOx emission rate that will apply beginning with the 2024 ozone season. Daily average emissions above the backstop rate will result in having to surrender extra allowances. This daily backstop emission rate, which is 0.14 lb/MMBtu, will apply to Unit 3 if finalized as proposed. Unit 3 currently has a 30-day rolling average NOx limit of 0.100 lb/MMBtu. The shorter averaging period will require CEI South to keep the daily average emission rate below the backstop rate in order to avoid having to surrender extra seasonal allowances. Air emissions allowance costs are accounted for within IRP modeling.

Figure 11.27 – Air Pollution Control Devices Installed

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	240
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

Figure 11.28 – CSAPR Seasonal NOx Allowances

	A.B. Brown	BAGS[75]	F.B. Culley	SIGECO W4	Total
2020	658	6	465	226	1355
2021	561	8	422	184	1167
2022	410	0	307	134	851
2023	TBD	0	TBD	TBD	TBD

11.2.2 Solid Waste Disposal

Scrubber by-products from A.B. Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management ("IDEM"). Since February 2010, the majority of A.B. Brown fly ash is diverted from the ash pond and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. Recently, CEI South completed the infrastructure needed for the excavation and barge loading of ponded ash to also be sent for beneficial reuse in cement processing, to be sent for beneficial reuse by a cement processing plant in St. Genevieve, Missouri. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of CEI South's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and instead transported offsite for recycling into a cement application. Additionally, these major sustainability projects serve to mitigate the negative impacts that are associated with closing the ash pond by leaving the CCR material in place.

Fly ash from the F.B. Culley facility is similarly transported off-site for beneficial reuse in cement. The F.B. Culley facility completed the conversion of the Unit 3 bottom ash system to a dry system in December 2020 and sends the bottom ash to beneficial reuse. The

[75] Retired

F.B. Culley facility recently completed construction of a GeoTube Containment Area that collects the bottom ash and drains the filtrate to a lined pond. The collected bottom ash will be sent to beneficial reuse. Additionally, the F.B. Culley facility recently completed the construction of a Spray Dryer Evaporator to handle the FGD Wastewater from the scrubber. The East Ash Pond (approximately 10 acres) is now no longer receiving any waste streams and will be closed. 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 also used for beneficial reuse and shipped by river barge from F.B. Culley to a wallboard manufacturer. In summary, the majority of CEI South's coal combustion material is no longer handled on site but is being recycled and shipped off-site for beneficial reuse.

11.2.3 Hazardous Waste Disposal

CEI South’s A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include 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.

11.2.4 Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under NPDES water discharge permits issued by the IDEM. A.B. Brown utilizes cooling towers 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.

11.3 DSM APPENDIX

11.3.1.1 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 2-3 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.

11.3.1.2 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 6.19% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on May 29, 2019 in Cause No. 44910.

Figure 11.29 – 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
6.19Utility 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)

11.3.2 Gross Savings 2021-2023

Figure 11.30 – 2021-2023 Plan Gross kWh Energy Savings

	2021[76]		2022[77]		2023[78]	
Sector	**Gross kWh Energy Savings**	**KW Demand Savings**	**Gross kWh Energy Savings**	**KW Demand Savings**	**Gross kWh Energy Savings**	**KW Demand Savings**
Residential	19,719,005	4,392	15,671,971	3,794	15,590,458	6,310
Commercial & Industrial	20,179,465	5,358	17,643,327	3,004	27,923,605	4,105
Total	39,898,470	9,750	33,315,297	6,799	43,514,063	10,415

[76] 2021 Evaluation Results used for 2021
[77] 2022 Evaluation Results used for 2022
[78] 2023 Operating Plan used for 2023 Savings

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.

11.3.3 Impacts

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

Figure 11.31 – 2021 Evaluated Electric DSM Program Savings

Program	Residential/ Commercial	Participants *	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Specialty Lighting	Residential	153,173	35%	5,861,368	38	2,062,730	808	0.005	400.5
Residential Prescriptive	Residential	7,667	58%	3,371,863	440	1,955,763	1,658	0.216	1,495.5
Residential New Construction	Residential	256	57%	144,301	564	82,251	57	0.223	65.4
Income Qualified Weatherization	Residential	7,644	100%	374,823	49	374,823	56	0.007	112.0
Residential Behavioral Savings	Residential	49,228	100%	7,089,988	144	7,089,988	1,431	0.029	1,350.0
Appliance Recycling	Residential	1,497	52%	1,376,142	919	710,771	214	0.143	95.0
Smart Cycle (Smart Thermostats)	Residential	178	94%	90,238	507	85,073	-	-	550.0
Community-Based LED Distribution	Residential	53,672	91%	1,410,282	26	1,278,861	167	0.003	161.0
C&I Prescriptive	Commercial	31,062	76%	13,038,378	420	9,909,167	3,757	0.121	2,368.8
C&I Custom	Commercial	17	93%	1,714,556	100,856	1,594,537	376	22.098	578.3
Small Business Energy Solutions	Commercial	20,820	88%	5,426,531	261	4,775,347	1,225	0.059	449.7
Portfolio Total		325,215	75%	39,898,470	123	29,919,313	9,750	0.030	7,626.2

* Participants are the Verified installations

Figure 11.32 – 2022 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Specialty Lighting	Residential	126,549	35%	5,209,860	41	1,838,599	718	0.006	253.5
Residential Prescriptive	Residential	6,772	60%	2,460,580	363	1,469,508	1,024	0.151	552.9
Residential New Construction	Residential	42	57%	20,933	498	11,932	8	0.200	4.8
Income Qualified Weatherization	Residential	3,217	100%	182,201	57	182,201	44	0.014	43.7
Residential Behavioral Savings	Residential	136,449	100%	5,396,100	40	5,396,100	1,684	0.012	1,684.5
Appliance Recycling	Residential	1,078	52%	1,009,663	937	521,359	155	0.144	83.3
Smart Cycle (Smart Thermostats)	Residential	82	94%	39,550	482	37,277	-	-	-
Community-Based LED Distribution	Residential	60,262	100%	1,353,085	22	1,353,085	160	0.003	160.2
C&I Prescriptive	Commercial	482	63%	10,641,878	22,079	6,704,383	1,532	3.178	964.9
C&I Custom	Commercial	47	58%	1,444,307	30,730	837,698	367	7.801	212.7
Small Business Energy Solutions	Commercial	14,686	88%	5,557,142	378	4,890,285	1,106	0.075	973.5
Portfolio Total		349,666	70%	33,315,297	95	23,242,425	6,799	0.019	4,933.9

* Participants are the Verified installations

Figure 11.33 – 2023 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Prescriptive	Residential	22,079	56%	5,608,817	254	3,119,934	624	0.028	347.0
Residential New Construction	Residential	275	54%	42,857	156	23,143	29	0.105	15.7
Income Qualified Weatherization	Residential	760	100%	279,724	368	279,724	83	0.109	83.0
Community Connections	Residential	29,361	100%	591,172	20	591,172	18	0.001	17.9
Residential Behavioral Savings	Residential	44,661	100%	6,790,000	152	6,790,000	1,340	0.030	1,339.8
Appliance Recycling	Residential	1,370	67%	1,213,178	886	815,198	194	0.142	130.3
Conservation Voltage Reduction	Residential	4,491	100%	805,226	179	805,226	613	0.136	612.8
SmartDLC - Wifi DR/DLC Changeout	Residential	500	100%	259,484	519	259,484	550	1.100	550.0
BYOT (Bring Your Own Thermostat)	Residential	2,600	100%				2,860	1.100	2,860.0
Commercial & Industrial Prescriptive	Commercial	17,943	86%	15,000,000	836	12,900,000	2,567	0.143	2,207.8
Commercial & Industrial Custom	Commercial	59	96%	5,000,000	84,746	4,800,000	671	11.365	643.7
Small Business Direct Install	Commercial	181	93%	6,500,000	35,912	6,045,000	471	2.601	437.8
Conservation Voltage Reduction	Commercial	560	100%	1,423,604	2,542	1,423,604	396	0.708	396.3
Portfolio Total		124,840	87%	43,514,063	349	37,852,486	10,415	0.083	9,642.1

11.3.4 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 236 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 base optimized scenario under base 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 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 236 MW 1x F-class simple cycle gas turbine is avoided.

Figure 11.34 – 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
2023	$119.51	$9.31	$128.82	$5.68	$68.32
2024	$122.25	$8.94	$131.19	$4.65	$52.70
2025	$125.05	$8.82	$133.88	$4.43	$47.17
2026	$127.92	$8.94	$136.87	$4.50	$47.48
2027	$130.85	$9.15	$140.00	$4.57	$41.96
2028	$133.85	$9.42	$143.28	$4.70	$41.14
2029	$136.92	$9.63	$146.55	$4.87	$40.28
2030	$140.06	$9.91	$149.97	$5.05	$41.62
2031	$143.27	$10.19	$153.47	$5.23	$40.86
2032	$146.56	$10.36	$156.92	$5.39	$39.79
2033	$149.92	$10.60	$160.51	$5.55	$40.31
2034	$153.36	$10.85	$164.20	$5.72	$42.31
2035	$156.87	$11.11	$167.98	$5.83	$43.66
2036	$160.47	$11.36	$171.83	$6.03	$45.41
2037	$164.15	$11.61	$175.76	$6.26	$47.36
2038	$167.91	$11.88	$179.79	$6.48	$49.01
2039	$171.76	$12.15	$183.91	$6.71	$51.39
2040	$175.70	$12.43	$188.13	$7.00	$53.62
2041	$179.73	$12.72	$192.44	$7.22	$55.48
2042	$183.85	$13.01	$196.85	$7.59	$58.29

11.4 RESOURCE OPTIONS APPENDIX

11.4.1 Existing Resource Studies

11.4.1.1 Coal to Gas Conversion

The conversion of F.B. Culley Unit 2 and 3 existing coal fired boilers to burn natural gas instead of coal was studied. Conceptual design studies were developed by an engineering firm to determine natural gas conversion MW output, heat rate performance, emissions and balance of plant equipment. Engineering and construction estimates were developed to determine high level AACE Class IV installation costs. The converted unit 3 is expected to be operated as a peaking facility on 100% natural gas. Natural gas conversion of the units reduces boiler efficiency compared to the coal fired design and slightly increases net plant heat rate.

11.4.1.2 ACE Rule Compliance (CO_2 Proxy)

In the 2022-2023 IRP CEI South used the estimated costs for F.B. Culley 3 to comply with the ACE Rule as a proxy for future carbon legislation. These costs were originally developed for the 2019 IRP before retirement decisions were made for A.B. Brown 1 & 2 and FB. Culley 2. The sections below explain how these costs were originally developed for all coal units.

The Affordable Clean Energy ("ACE") rule, finalized by the United States EPA June 19, 2019 and ultimately vacated on January 19, 2021, established new standards for reducing greenhouse gas emissions for coal fired electric utility generating units. The rule was reinstated on October 27, 2022, thereby requiring states to submit their state plans required under the rule. On March 2, 2023, EPA extended the state submittal deadline to April 15, 2024. Most recently, on May 11, 2023, EPA announced a proposal to repeal the ACE rule. ACE details specific heat rate improvement techniques, called Best System of Emission Reduction ("BSER"), were meant to be the best technology options or other measures that have been known to reduce plant heat rate.

The specific candidate technology options are as follows:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive ("VFD") deployment.
- Neural networks.
- Intelligent sootblowing ("ISB").
- Boiler Feed Pump Upgrades.
- Equipment & facilities improvements to enhance O&M practices.

In the 2019/2020 IRP potential alternatives for improvements at the four coal fired units A.B. Brown Units 1 & 2 and F.B. Culley Units 2 & 3 were assessed to meet the goals of the ACE rule, on a 2019 Cost Basis. Applicability of candidate technologies for the four existing coal fired units is found in the "ACE Heat Rate Improvement Study" located in technical appendix 6.6. The characteristics of the four plants were reviewed and each plant was examined according to applicable BSER alternatives. Estimates of heat rate improvement, annual carbon dioxide reduction, O&M and a rough order of magnitude capital cost estimate were developed for each applicable alternative.

11.4.1.3 Cogeneration Study

A study was performed to evaluate the performance of a potential cogeneration partnership with a CEI South industrial customer. Conceptual design studies were developed by an engineering firm to determine the cogeneration MW output, capital cost, and O&M cost. Engineering and construction estimates were developed to determine high level AACE Class V estimates.

11.4.2 Approximate Net and Gross Dependable Generating Capacity

Figure 11.35 – Approximate Net and Gross Dependable Generating Capacity

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
A.B. Brown 1	265	245
A.B. Brown 2	260	240
A.B. Brown 3	74	74
A.B. Brown 4	74	74

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
F.B. Culley 2	100	90
F.B. Culley 3	287	270
Warrick 4	162	150
Troy Solar	50[79]	50

11.4.3 New Construction Alternatives

Figure 11.36 – New Construction Alternatives

Technology	Fuel	Screened	Capacity (kW)
Hydroelectric	Hydro	No	36,000/22,000
Generic Wind	Wind	No	200,000
Li-Ion Battery Storage (paired 50MW Generic Wind) (4 hour)	Storage	No	10,000
Generic Solar PV	Solar	No	10,000
Generic Solar PV	Solar	No	50,000
Generic Solar PV	Solar	No	100,000
Li-Ion Battery Storage (paired 50MW Generic Solar PV) (4 hour)	Storage	No	10,000
Li-Ion Battery Storage (4 hour)	Storage	No	10,000
Li-Ion Battery Storage (4 hour)	Storage	No	50,000
Li-Ion Battery Storage (4 hour)	Storage	No	100,000
Long Duration Storage	Storage	No	300,000
Demand Side Management Vintage 1 (2025-27)	Storage	No	Varies
Demand Side Management Vintage 2 (2028-30)	Storage	No	Varies
Demand Side Management Vintage 3 (2031-42)	Storage	No	Varies
Supercritical with Carbon Capture & Storage	Coal	No	500,000
Ultra-supercritical with Carbon Capture & Storage	Coal	No	750,000
F-Class CT	Natural Gas	No	229,000
J-Class CT	Natural Gas	No	372,000
GH-Class CT	Natural Gas	No	287,000
F-Class CCGT (Fired)	Natural Gas	No	363,000
F-Class CCGT (Unfired)	Natural Gas	No	365,000
GH-Class CCGT (Fired)	Natural Gas	No	428,000
GH-Class CCGT (Unfired)	Natural Gas	No	431,000
J-Class CCGT (Fired)	Natural Gas	No	1,101,000
J-Class CCGT (Unfired)	Natural Gas	No	551,000
Brown 5&6 Retrofit	Natural Gas	No	257,000

[79] Maximum output shown but output varies from season to season and day to day

Technology	Fuel	Screened	Capacity (kW)
Co-Gen	Natural Gas	Yes[80]	22,000
FB Culley Conversion	Natural Gas	No	Varies
Aeroderivative[81]	Natural Gas	No	255,000
Reciprocating Internal Combustion Engines (6x9)	Natural Gas	No	54,500
Reciprocating Internal Combustion Engines (618)	Natural Gas	No	110100
Small Modular Reactor	Nuclear	No	77,000
Annual MISO Capacity Market Purchase	Capacity	No	Varies

11.5 RISK APPENDIX

The probabilistic risk assessment allows for the development of portfolio results based on a range of possible input values developed from the same stochastic process. The probability risk assessment is based on defining uncertainty around monthly coal prices, natural gas prices, CO_2 prices, peak load and capital costs for solar, wind and storage. With the uncertainty around the variables defined by probability distributions, the variables were modeled stochastically using EnCompass' monte carlo sampling capability. 200 iterations were run to create 200 sets of stochastically developed inputs. These 200 sets of stochastic inputs were then run through the dispatch model one set at a time for the selected portfolios. 200 instances of key metrics from the dispatch modeling were used to form distributions around the key output metrics. Thus, stochastically developed inputs allow for the testing of each portfolio's performance across a wide range 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.

[80] Co-generation facilities are dependent on being co-located with an industrial customer; this option was not considered in reference case optimization.
[81] Aeroderivative units were not originally included as a new construction alternative and were later added and tested in specific runs based on RFP bid received.

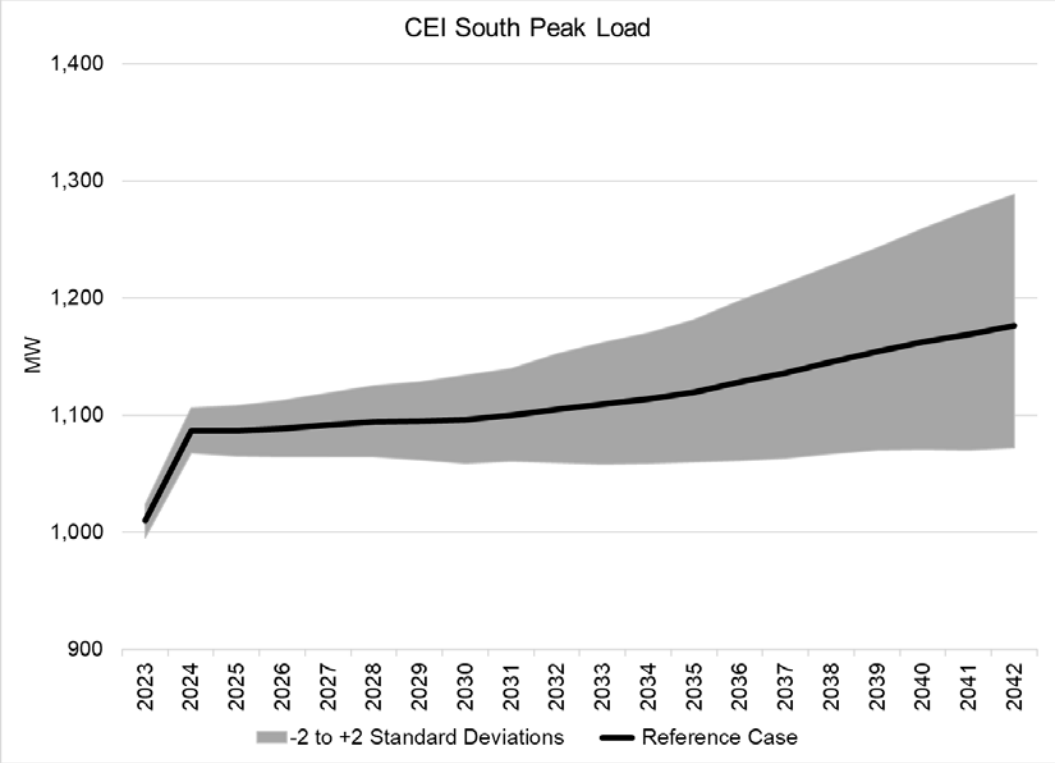
11.6 Probability Distributions

To perform the probabilistic modeling (stochastics), a set of monthly probability distributions that describe uncertainty was required for each of the key market driver variables described above (natural gas prices, coal prices, CO_2 prices, peak demand and capital costs for renewables). Monthly lognormal probability distributions were assumed for natural gas prices, coal prices and peak demand. Monthly discrete distributions were assumed for CO_2 prices and renewables capital costs. The lognormal probability distributions were stochastically simulated together in EnCompass with cross-variable correlation. 200 iterations were run stochastically, which produced 200 sets of correlated inputs for natural gas prices, coal prices and peak demand. This stochastics runs in EnCompass assumed 100 percent mean reversion. The discrete distributions for CO_2 prices and renewables capital costs were assigned to each of the 200 stochastic iterations based on assumed correlations. This resulted in 200 sets of probabilistic inputs that were then fed through the dispatch cost modeling. The following sections describe the methodologies for developing these stochastic variables.

11.6.1 Load Uncertainty

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, 1898 & Co. developed defined uncertainty around the monthly expected peak load for the CEI South control area. Varying the components that make up peak demand, 1898 & Co. developed a set of likely peak demand scenarios, ranging low end expectations to high end expectations. Monthly averages and standard deviations were developed from these demand scenarios and applied to a lognormal distribution to develop the monthly peak demand probability distribution used in the stochastic modeling.

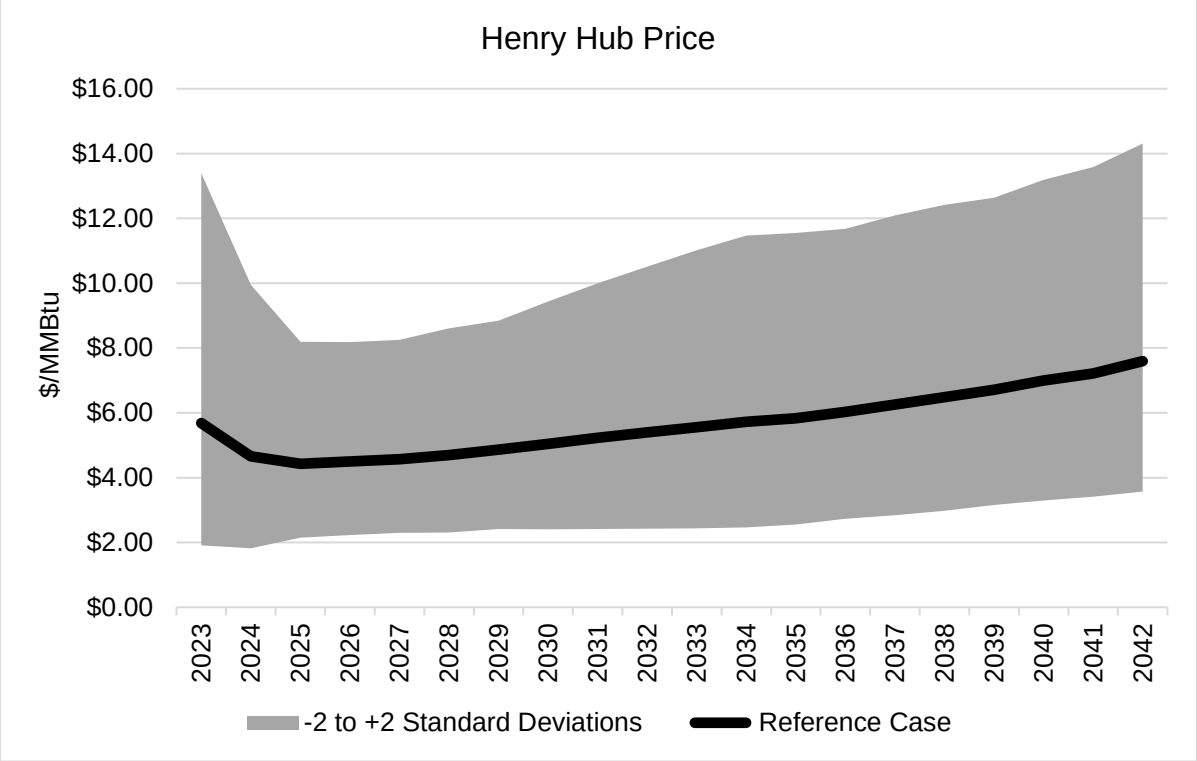
Figure 11.37 –CEI South Load Distribution (Megawatts)



11.6.2 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 from CEI South's price forecast vendor 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 monthly lognormal probability distribution for natural gas pricing, which were in turn used in the stochastic modeling that developed the 200 sets of stochastic inputs.

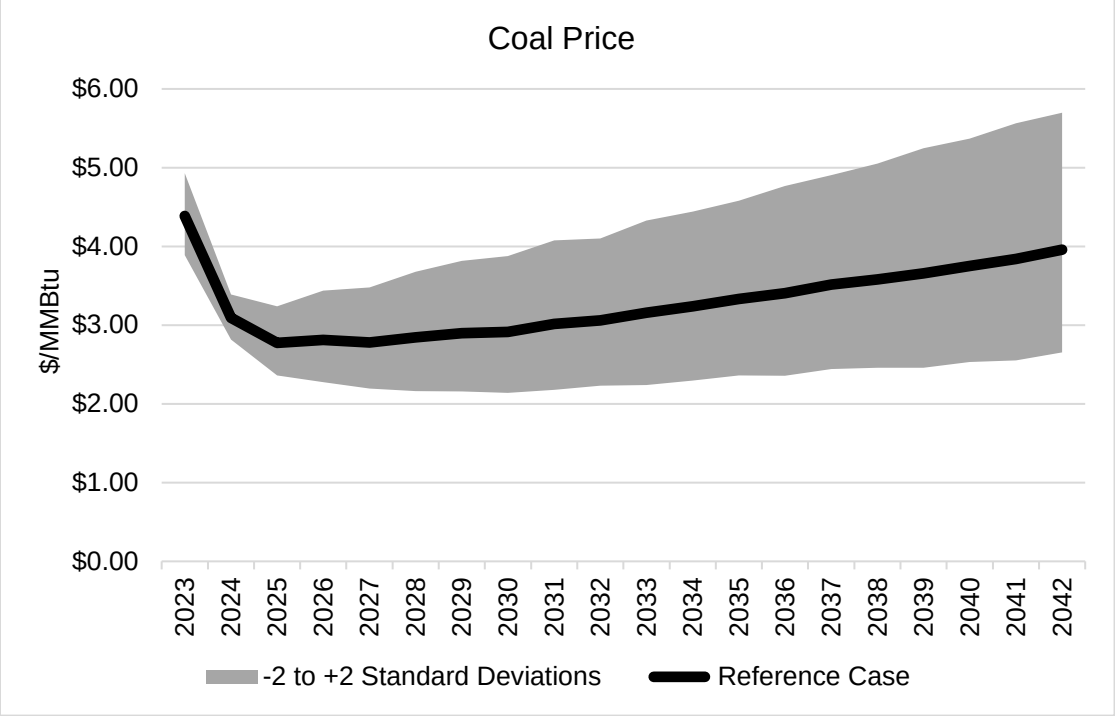
Figure 11.38 –Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu)



11.6.3 Coal Price Uncertainty

To define the uncertainty around coal prices to be used in the stochastic modeling, 1898 & Co. relied on the base, high and low coal price forecasts from CEI SOUTH's price forecast vendor 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 monthly lognormal probability distribution for coal pricing, which were in turn used in the stochastic modeling that developed the 200 sets of stochastic inputs.

Figure 11.39 –Coal Price Distribution (Nominal$/MMBtu)



11.6.4 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 and Decarbonization/Electrification scenarios. Because of these assumptions, CO_2 price uncertainty is assigned on a discrete basis. Specifically, 1898 & Co. assigned a zero price for CO_2 for the first 120 iterations out of the 200 iterations of stochastic inputs. The next 40 iterations were assigned the CO_2 price from the Decarbonization/Electrification scenario. The last 40 iterations were assigned the highest case CO_2 prices, which are those from the High Regulatory scenario.

11.6.5 Capital Cost Uncertainty

1898 & Co. developed base, high and low solar, wind and storage resource capital costs for use in the scenario analyses. The base forecast for renewable capital costs were developed using the average price for purchase options received in the All-Source RFP.

The proposals reflect up to date near term renewable purchase options and were forecasted through the study period using capital cost estimates from the NREL. The low forecast follows the same methodology for development; however, the lowest purchase price was used as the starting point for the forecast. Finally, the high forecast begins from the highest renewable purchase option price and continues through the study period at the assumed escalation rate (2.3%).

The base, high and low capital costs were developed based on fundamental assumptions and do not conform to a specific probability distribution type. As a result, the renewables capital costs were not included in the stochastics analysis performed in EnCompass for natural gas prices, coal prices and peak demand. Instead, the base, high and low renewables capital costs were treated as discreet distributions and assigned to the 200 iterations for inclusion with the other stochastically develop input variables. The low capital costs were assigned to the first 50 iterations of stochastic variables. The base, or Reference Case capital costs were assigned to the next 100 iterations. The high capital costs were assigned 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.

Figure 11.40 – Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2022	$1,943	$1,700	$2,057	$1,172
2023	$1,943	$1,700	$2,057	$1,149
2024	$1,943	$1,700	$2,057	$1,125
2025	$1,943	$1,700	$2,057	$1,100
2026	$1,943	$1,700	$2,057	$1,073
2027	$1,891	$1,663	$2,104	$1,044
2028	$1,836	$1,626	$2,152	$1,014
2029	$1,777	$1,589	$2,201	$981
2030	$1,714	$1,552	$2,252	$946
2031	$1,737	$1,515	$2,303	$959
2032	$1,761	$1,478	$2,356	$973
2033	$1,785	$1,442	$2,410	$986
2034	$1,809	$1,405	$2,465	$999
2035	$1,834	$1,368	$2,522	$1,013
2036	$1,858	$1,331	$2,580	$1,026
2037	$1,883	$1,294	$2,639	$1,040
2038	$1,908	$1,257	$2,699	$1,054
2039	$1,933	$1,220	$2,761	$1,067
2040	$1,958	$1,183	$2,825	$1,081
2041	$1,983	$1,146	$2,889	$1,095
2042	$2,009	$1,109	$2,956	$1,109

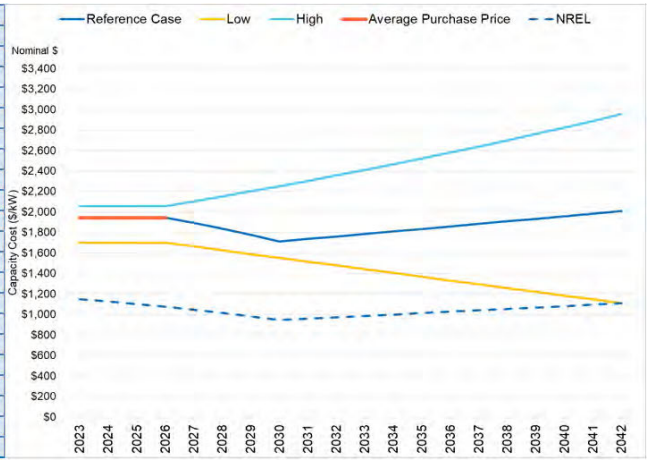


Figure 11.41– Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2022	$2,314	$2,100	$2,314	$1,423
2023	$2,314	$2,100	$2,314	$1,400
2024	$2,314	$2,100	$2,314	$1,377
2025	$2,314	$2,100	$2,314	$1,351
2026	$2,314	$2,100	$2,314	$1,325
2027	$2,265	$2,055	$2,367	$1,297
2028	$2,212	$2,011	$2,421	$1,266
2029	$2,155	$1,966	$2,477	$1,234
2030	$2,095	$1,921	$2,533	$1,199
2031	$2,121	$1,877	$2,592	$1,214
2032	$2,148	$1,832	$2,651	$1,230
2033	$2,175	$1,787	$2,712	$1,245
2034	$2,202	$1,743	$2,774	$1,260
2035	$2,229	$1,698	$2,837	$1,276
2036	$2,256	$1,653	$2,903	$1,291
2037	$2,283	$1,609	$2,969	$1,307
2038	$2,310	$1,564	$3,037	$1,323
2039	$2,337	$1,519	$3,107	$1,338
2040	$2,365	$1,474	$3,178	$1,354
2041	$2,392	$1,430	$3,251	$1,369
2042	$2,419	$1,385	$3,325	$1,385

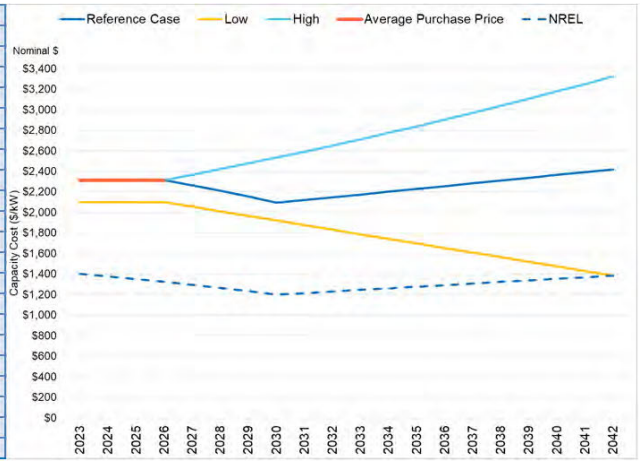
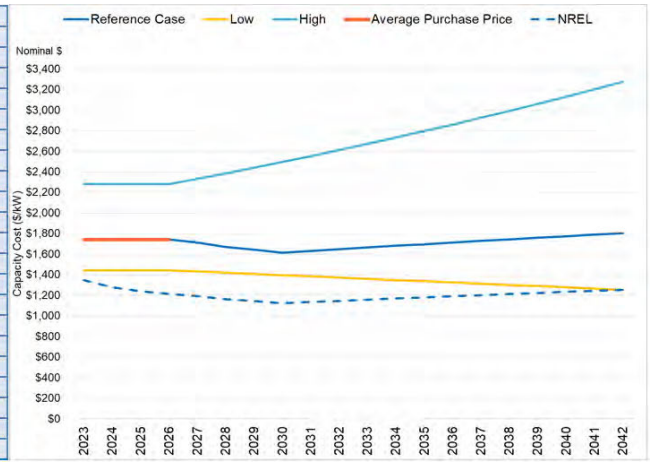


Figure 11.42– Lithium-Ion 50 MW/ 200 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)

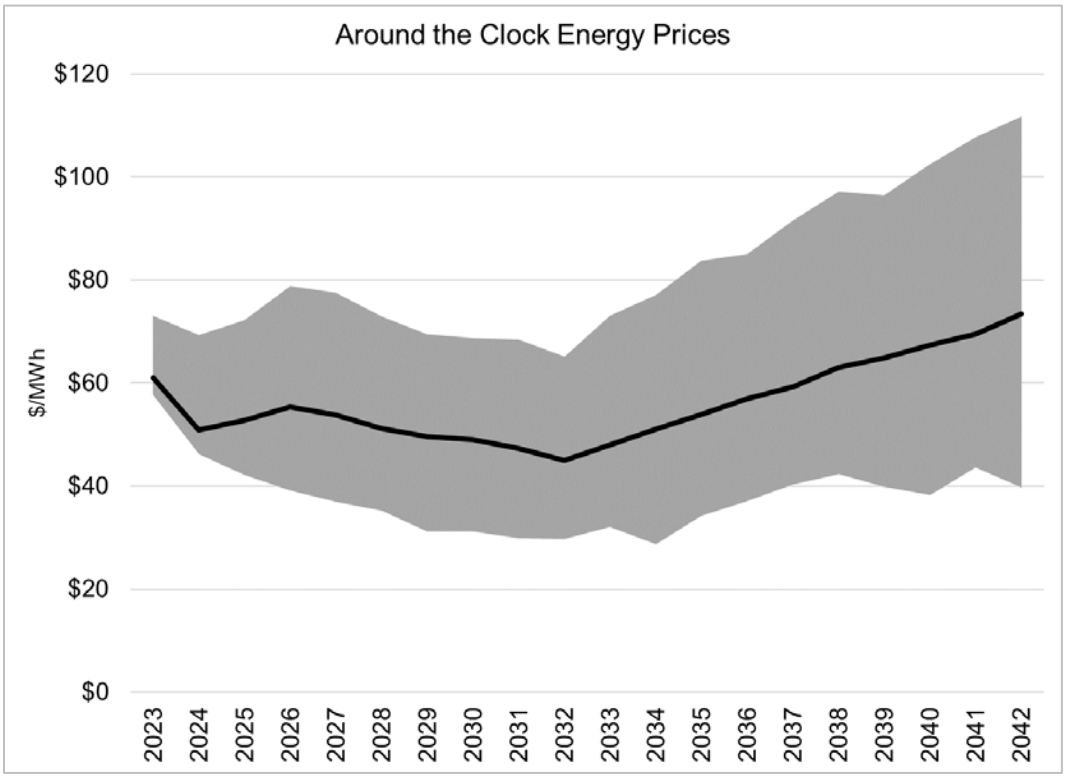
Year	Reference Case	Low	High	NREL
2022	$1,742	$1,443	$2,279	$1,434
2023	$1,742	$1,443	$2,279	$1,344
2024	$1,742	$1,443	$2,279	$1,277
2025	$1,742	$1,443	$2,279	$1,236
2026	$1,742	$1,443	$2,279	$1,211
2027	$1,711	$1,431	$2,331	$1,190
2028	$1,669	$1,419	$2,385	$1,160
2029	$1,643	$1,407	$2,439	$1,142
2030	$1,614	$1,395	$2,495	$1,122
2031	$1,632	$1,383	$2,553	$1,134
2032	$1,648	$1,372	$2,611	$1,146
2033	$1,664	$1,360	$2,671	$1,157
2034	$1,680	$1,348	$2,732	$1,168
2035	$1,696	$1,336	$2,795	$1,179
2036	$1,712	$1,324	$2,859	$1,190
2037	$1,727	$1,312	$2,924	$1,201
2038	$1,743	$1,300	$2,991	$1,212
2039	$1,758	$1,289	$3,060	$1,222
2040	$1,773	$1,277	$3,130	$1,233
2041	$1,788	$1,265	$3,202	$1,243
2042	$1,802	$1,253	$3,275	$1,253



11.6.6 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 prices 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 monthly natural gas price for the 200 iterations to arrive at monthly energy prices for each iteration.

Figure 11.43 –Stochastic Inputs – Energy Prices – Market Forecast



11.6.7 Affordability Ranking

Figure 11.44– Probabilistic 20-Year Mean NPV $ Million[82]

Portfolio	20 Year NPVRR ($M)	Cents/kWh Delivered	% Above Reference Case
Reference Case	$4,214	6.52	100.0%
F-Class CT	$4,499	6.96	106.7%
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.96	106.8%
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	6.97	107.0%
Replace FB Culley 3 with Storage and Solar	$4,539	7.02	107.7%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	7.05	108.2%
Replace FB Culley 3 with Storage and Wind	$4,580	7.08	108.7%
Business as Usual	$4,581	7.08	108.7%
Diversified Renewables	$4,583	7.09	108.8%
Diversified Renewables (Early Storage & DG Solar)	$4,676	7.23	111.0%

11.7 TRANSMISSION APPENDIX

11.7.1 Transmission and Distribution Planning Criteria

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:

a) Developing a transmission 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 or set of contingencies;

b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;

[82] The energy delivered is a 20-year present value of the Energy Requirement discounted at 5.71 percent, rather than a total sum. This reflects a levelized net present value calculation for the cost per delivered kWh.

c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) 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;
f) Coordinating transmission planning activities in broader regional evaluations with the MISO, ReliabilityFirst ("RF") and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth and to address age and condition of existing facilities; and
j) Ensuring compliance with FERC, NERC and RF Reliability Standards for transmission planning.

11.7.2 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 and Transmission Service Requests 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 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 a 345kV Market Efficiency Project between CEI South's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project was completed and placed into -service in late 2020. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. CEI South partnered with PSEG in submitting a proposal to MISO to construct the line; however, the project was awarded to Republic Transmission, LLC. CEI South, as the incumbent transmission owner, was responsible for the Duff substation modifications required for the project. The overall project cost was shared according to MISO's Tariff. The project not only provided regional economic benefits, but also enhanced grid reliability in the area of CEI South's Newtonville substation.

11.7.3 Transmission Assessment

CEI South's most recent transmission assessment was completed in 2019. The study used the final Multiregional Modeling Working Group ("MMWG") 2018 Series Models, which includes the CEI South full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.11 software was used to conduct the assessment.

CEI South's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the 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 2019, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-19.

The CEI South Bulk Electrical System (100kV and above) is expected to be stable and perform well through 2029. 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.

CEI South recently completed a new 138kV line from Toyota South substation to Scott Township substation which provides a key customer improved reliability. Prior to this new line, the loss of the existing two 138kV lines (both from Francisco substation) into Toyota substation resulted in the loss of service to the Toyota manufacturing facility. This line

also serves as a second line into Scott Township substation, which was on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This new line is also a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

As previously mentioned, the new 138kV East/West line from AB Brown station to Pigeon Creek to Warrick North station also provides several key benefits to the transmission system. This line was completed and put into service in February 2023. Overall benefits include a reduced power flow on the 69kV system, improved import capability from the 345kV system, better flexibility on 138kV outages, and system support for future generation changes.

The only mentionable extreme contingency is for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that CEI South prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System ("BES"). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines were recently completed as alternate feeds to reduce outage times.

- A new 69kV line installed between Boonville and Boonville Pioneer Substation (placed in-service in 2021).
- A new 69kV line installed as a second source to Paradise distribution substation (placed in-service in 2021)

These are not NERC reliability driven projects but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Several new substations will be completed in 2023 to account for additional residential and industrial load growth. Anderson Road is a new distribution substation recently installed to meet residential load growth. There are also plans to add additional power transformers at existing distribution substations to support load growth and facilitate 4kV to 12kV conversion projects. Darlington Road is a 138kV transmission station installed to support approximately 80MW for Kaiser Aluminum with two dedicated 138kV feeders.

SECTION 12
TECHNICAL APPENDIX ATTACHMENTS

Attachment 1.1 Non-Technical Summary

Attachment 1.2 CEI South Technology Assessment Summary Table

Attachment 3.1 Stakeholder Materials

Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report

Attachment 4.2 CEI South Hourly System Load Data

Attachment 4.3 2023-2024 MISO LOLE Study Report

Attachment 4.4 Confidential Long-Term Electric Energy and Demand Input/Output files

Attachment 6.1 CEI South Electric 2021-2023 DSM Plan

Attachment 6.2 2022 DSM Market Potential Study

Attachment 6.3 All-Source RFP

Attachment 6.5 Conversion Studies (CT conversion, FB Culley Conversion, and Cogen)

Attachment 6.6 ACE Rule Heat Rate Study

Attachment 8.1 Balance of Loads and Resources

Attachment 8.2 Confidential EnCompass Input/Output Model Files

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 117
RTO Insider Article



Consumers Energy's J.H. Campbell coal plant | *Newkirk Electric Associates*

Aug 21, 2025 | John Cropley and Amanda Durish Cook

The U.S. Department of Energy has ordered the J.H. Campbell Generating Plant to remain available another 90 days, saying its capacity is needed to maintain *MISO* grid reliability.

Consumers Energy had planned to retire the 1,420-MW coal-fired facility in southwest Michigan on May 31, but DOE on May 23 issued an emergency order (*202-25-3*) under Section 202(c) of the Federal Power Act ordering it to remain ready to operate because of a shortage of electricity and capacity to generate electricity. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

That order expired at midnight Eastern time Aug. 21.

Energy Secretary Chris Wright issued the follow-up order (*202-25-7*) at 8:50 p.m. Eastern time Aug. 20; it expires Nov. 19.

Why This Matters

Why This Matters

The order is another move by the Trump administration to use

aging fossil generation to shore up the grid.

In his Aug. 20 order, Wright indicated the generation shortfall in MISO is likely to continue.

President Donald Trump *declared an energy emergency* on his first day in office, and his Cabinet agencies have been scrambling to rejigger energy policy toward the fossil fuels he favors.

One of their stated priorities has been halting retirement of aging fossil-burning plants.

The order is another move by the Trump administration to use aging fossil generation to shore up the grid.

In a news release, Wright cited seasonal outlooks by *NERC* and NOAA warning of high temperatures in the Midwest as well as resource adequacy projections by MISO itself.

“The United States continues to face an energy emergency, with some regions experiencing more capacity constraints than others. With electricity demand increasing, we must put an end to the dangerous energy subtraction policies embraced by politicians for too long,” he said.

“This order will help ensure millions of Americans can continue to access affordable, reliable and secure baseload power regardless of whether the wind is blowing or the sun is shining.”

Section 202(c) has been a lightly used provision historically. Just 11 orders were issued during the Biden administration, all of them weather-related. This compares with *nine by Wright since mid-May*, only one of which was weather-related.

The cost of halting the J.H. Campbell retirement has been a point of contention. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month* and *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States*.)

It also has been unpopular with environmental advocates.

Sierra Club Beyond Coal Campaign Director Laurie Williams *said Aug. 21*: “By illegally extending this sham emergency order, Donald Trump and Chis Wright are costing hardworking Americans more money every single day for a coal plant that is unnecessary, deadly and extremely expensive.”

Earthjustice Senior Attorney Michael Lenoff said: “Chris Wright is not a Soviet-era central planner, but his new order suggests he would fit right in. The order purports to override the considered judgment and careful work of many federal, state and regional bodies who actually have authority to keep the lights on. In their place, Secretary Wright blunders in.”

In a statement, MISO said it will “continue coordinating with Consumers Energy to comply with the order.”

But MISO again stressed that J.H. Campbell did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year.

"MISO's 2025-2026 Planning Resource Auction indicated adequate resources to meet anticipated demand. State regulators along with utilities have the responsibility of ensuring resource adequacy. MISO remains focused on reliably operating the grid using the resources our members provide, while working closely with stakeholders and regulatory partners, providing visibility into system needs and sending market signals to inform long-term resource planning," MISO spokesperson Brandon Morris said in a statement to *RTO Insider*.

MISO leadership previously has said it might have to navigate similar future orders from the federal government to prop up retiring coal plants.

MISO Director Todd Raba said MISO might have to navigate similar edicts in the future, with about 30 coal plants in the footprint. At MISO's June board meeting, he said it's a "critical topic that will have huge implications in MISO."

Lawmakers, health professionals and other officials ***gathered*** near the plant in West Olive, Mich., on Aug. 12 to protest its extension. On Aug. 18, a small crowd of community members marched to U.S. Rep. Bill Huizenga's office in nearby Holland, Mich., to again protest continued operations.

Consumers Energy said it was evaluating the order extension and expects to "continue operating the plant as required by DOE."

"We have worked closely with MISO and have been operating in compliance with the order and MISO's dispatch requirements. All power generated by the Campbell plant and other Consumers generating plants is supplied to the MISO grid. Specific details on recent generation are not publicly available at this time," spokesperson Brian Wheeler told *RTO Insider*.

Wheeler also said the utility was "pleased" with ***FERC***'s approval of an allocation that's set to disburse cost recovery of the plant among the 11 states or portions of states in MISO Midwest.

Consumers Energy declined to comment on the coal plant's usefulness so far over the summer or how the plant will fit into the MISO market over the fall.

Data from power analytics company Yes Energy shows the 1.42-GW plant has been used consistently since the beginning of August, averaging an 84-88% hourly capacity factor.

COAL | RELIABILITY | RESOURCE ADEQUACY

KEYWORDS CHRIS WRIGHT | CONSUMERS ENERGY | FEDERAL POWER ACT SECTION 202 (C) | J.H. CAMPBELL PLANT | MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) | U.S. DEPARTMENT OF ENERGY (DOE)

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
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Exhibit 118
RMI Analysis of Coal Plants' Threats to Reliability



Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

August 12, 2025

By Gabriella Tosado, Ashtin Massie, Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Tweet

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable. it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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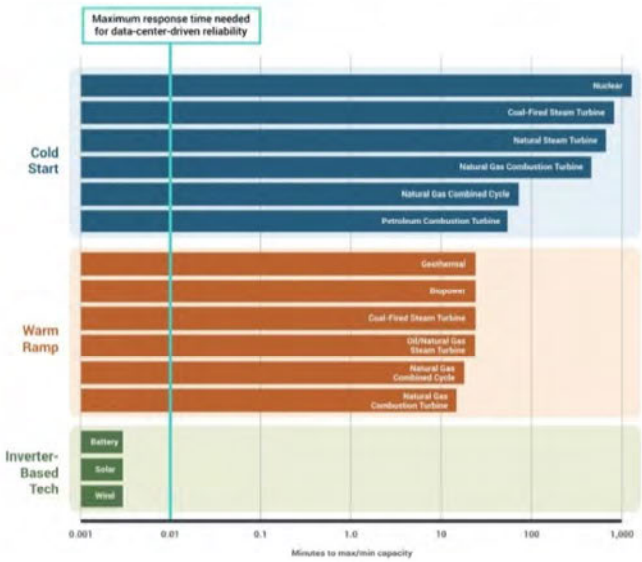
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

Shares

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.

Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
Power Couples	New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh.

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

RECOMMENDED READING



Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

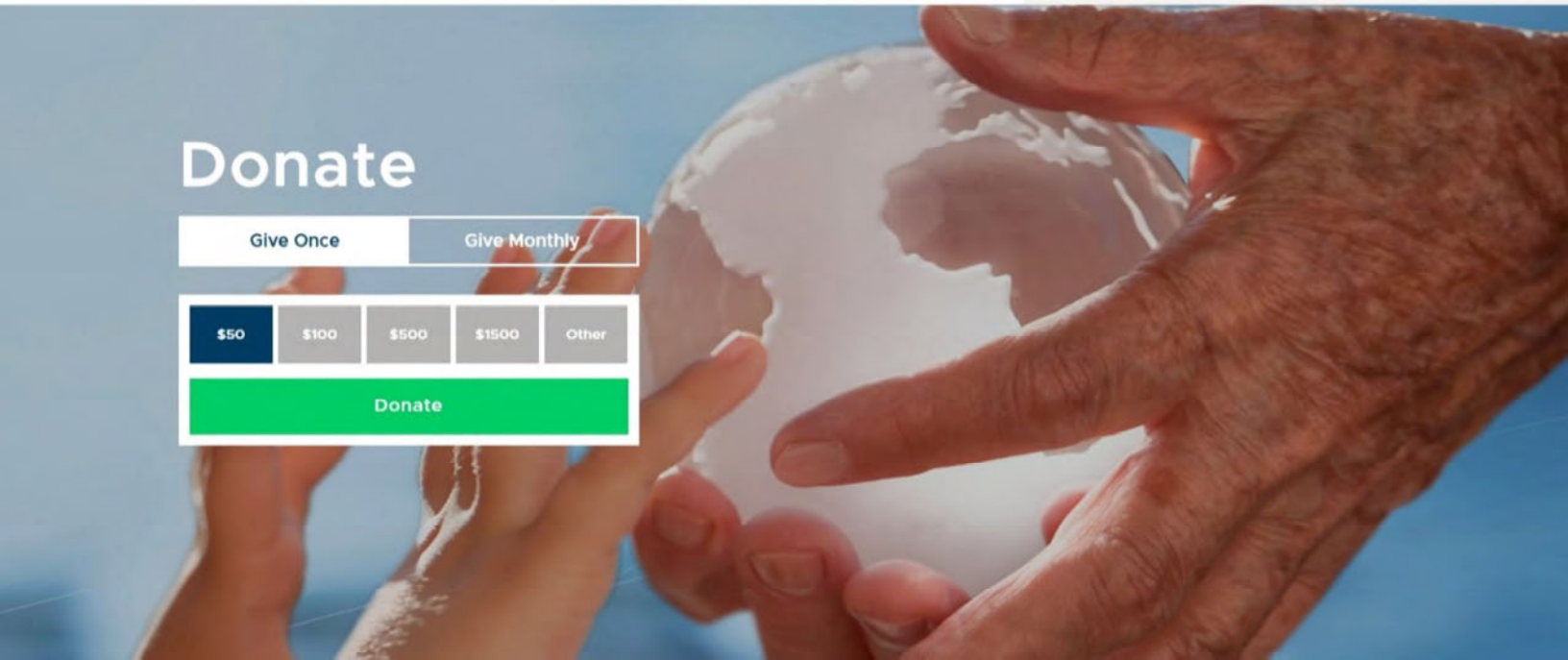
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Reinvesting at Coal Plant Sites with Clean Energy Upgrades Supports both Reliability and Affordability

July 16, 2025

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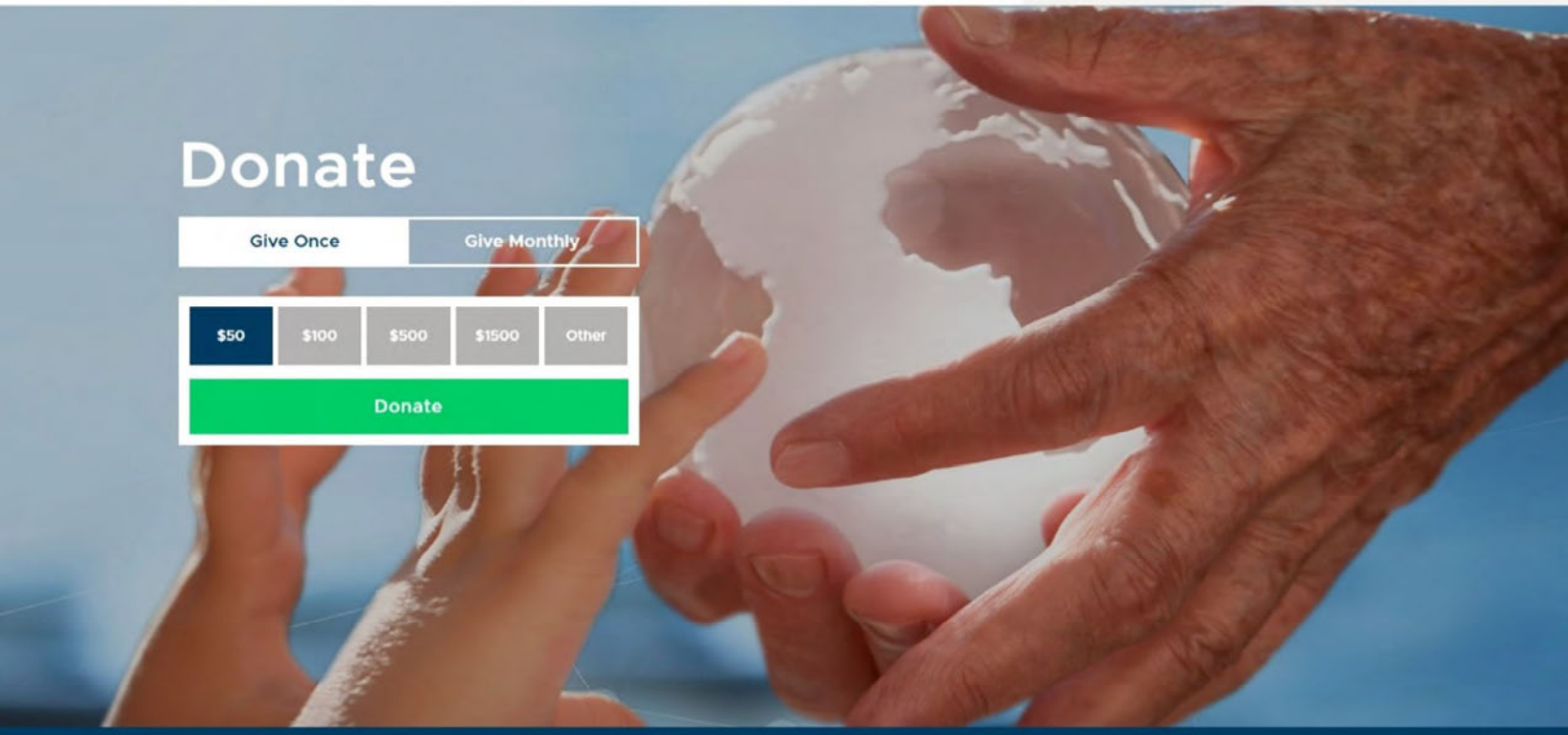


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Exhibit 119
MISO, ZRC Replacement Guidance

ZRC Replacement and instructions in the MECT

RASC

05/24/2023

Presentation updated as 7/11/2023
Updates are at the end of the deck Slides 12-17

Presentation updated as of 9/29/2023
Updates are on slides 14 & 17

Purpose and Key Takeaways

Purpose:

Provide Stakeholders with information and training on ZRC replacement in the MECT

Key Takeaways:

- ZRC replacement uses, and process explained and clarified
- ZRC replacement does not impact settlements from the PRA
- ZRC replacement is used for suspension, retirement, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season
- MECT User Guide has additional detail

Reasons to use ZRC Replacement

- Generators that have cleared a season(s) in the PRA that go on suspension, retirement or Catastrophic Generator Outage
- Cleared ZRCs for resources with planned generator outages and/or derates in excess of 31 days in a season
- ZRC replacement must overlap the suspension, retirement, catastrophic outage or outages/derates of the cleared generation being replaced
- Resources ZRCs cannot be replaced other than for the reasons listed above

31-day rule Capacity Replacement Clarification

ZRC Replacement FAQ

- ZRC replacement substitutes the Resource Adequacy Requirement (RAR) and Must Offer Obligation for the cleared resource

- Fully replaced resources (>95% cleared ZRC) will be granted Tier 1 & 2 exemptions during the replacement hours from Schedule 53 SAC calculation
  - Exemptions are for SAC calculations only, still subject to the capacity replacement rules and penalties
  - Exemptions for derates is still under discussion

- ZRC replacement does not impact settlements from the PRA, however resources that failed to meet the replacement requirement will incur non-compliance charges

Process for ZRC Replacement

- Use the "Replacement Calculator" on the MECT
- Obtain the ZRCs used in the replacement
- Submit the replacement on the "Resource Substitution" screen in the MECT
  - ZRC replacement should be entered into the MECT at least 7 calendar days prior to the effective date of replacement
- Contact MISO with any issues through the MISO help center

Use Replacement Calculator

- The Replacement Calculator is to verify that the prospective replacement ZRCs do not violate LCR, CIL or CEL for each zone when using ZRCs from another LRZ or ERZ

Zonal Data	PRMR (Obligation)	Offers Cleared + FRAP	LCR	Import Level (CIL)	Export Level (CEL)	Auction Import	Auction Export	Replacement Import	Replacement Export	Import Available	Export Available
1	18374.9	18661.2	16588.7	3754.0	3373.2	0.0	286.3	0.0	0.0	4040.3	3086.9
2	13449.9	13536.9	13017.5	1714.0	978.7	0.0	87.0	48.1	22.0	1774.9	917.8
3	9882.0	10391.1	7960.2	2896.0	4589.7	0.0	509.1	0.0	0.4	3405.5	4080.2

CALCULATE RESET

Calculator	Total MW needing replacement	Replacement ZRCs from the same zone	ZRCs from same zone after replacement	LCR test	Total Import Amount Needed	Amount Exported	Import Test	Export Test
1	200	100	18561.2	PASS	100	0	PASS	
2	0	0	13470.8	PASS		40		PASS
3	0	0	10331.5	PASS		60		PASS
4	0	0				0		

More information can be found in the MECT User Guide in section 31 & 32

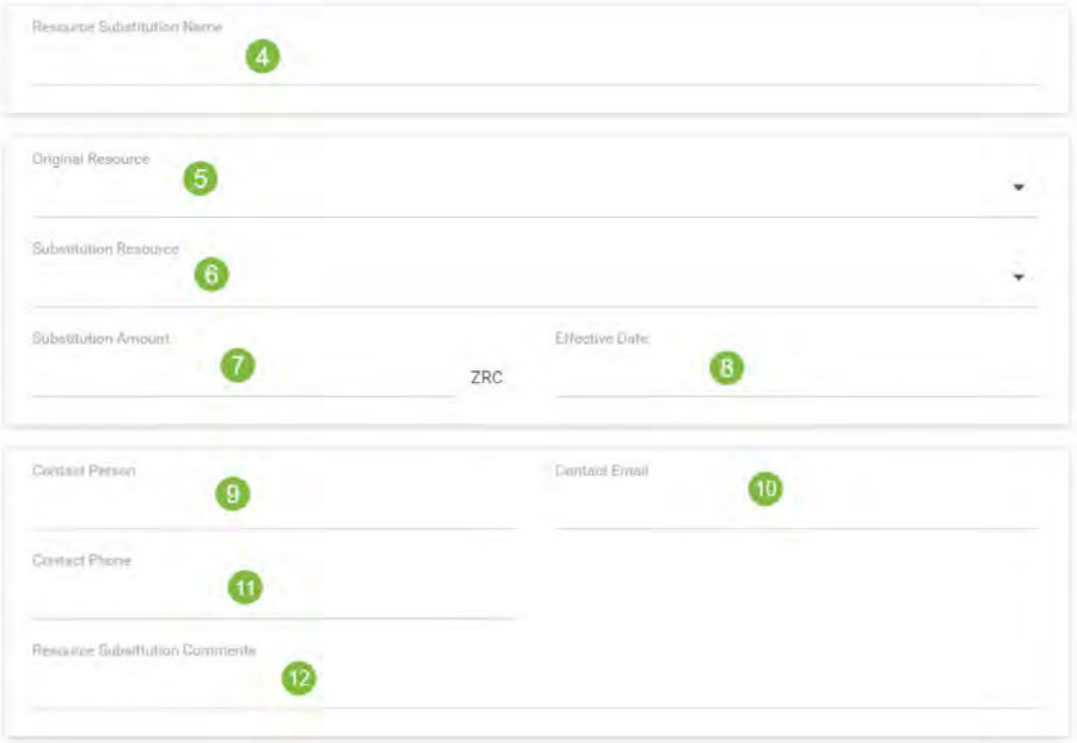
Obtain the ZRCs

- Market Participants will need the un-cleared ZRCs to use in the ZRC replacement
  - This can be from their own un-cleared ZRCs
  - This can be from a ZRC Transaction
    - Non-MISO Bulletin can be utilized to find ZRCs from other Market Participants

More information can be found in the MECT User Guide in section 18

ZRC Replacement in the MECT

- Navigate to the “Resource Substitution” screen in the MECT, fill in the form and submit



More information can be found in the MECT User Guide in section 30

Next Steps

- MECT release at the end of May will include an “end date” for ZRC replacement”. When the replacement is completed the ZRCs will be repopulated to the resource

- Additional details and screenshots will be added to this presentation and the MECT user guide and both will be reposted

Bullet point 3 updated on 7/12/2023

References

- MISO Resource Adequacy BPM-011-r27
  - Section 6.4, “Replacement Resources”
- MISO Tariff Module E-1
  - Section 69A.3.1.h, “Retirement, Suspension and Replacement of Planning Resources”
- MECT User Guide
  - Sections 18, 30, 31 and 32



https://help.misoenergy.org/support/

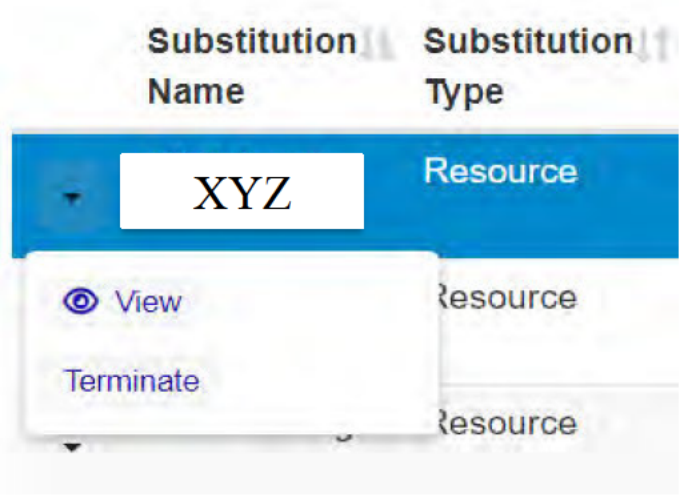
Additional Content added as of 7/11/2023

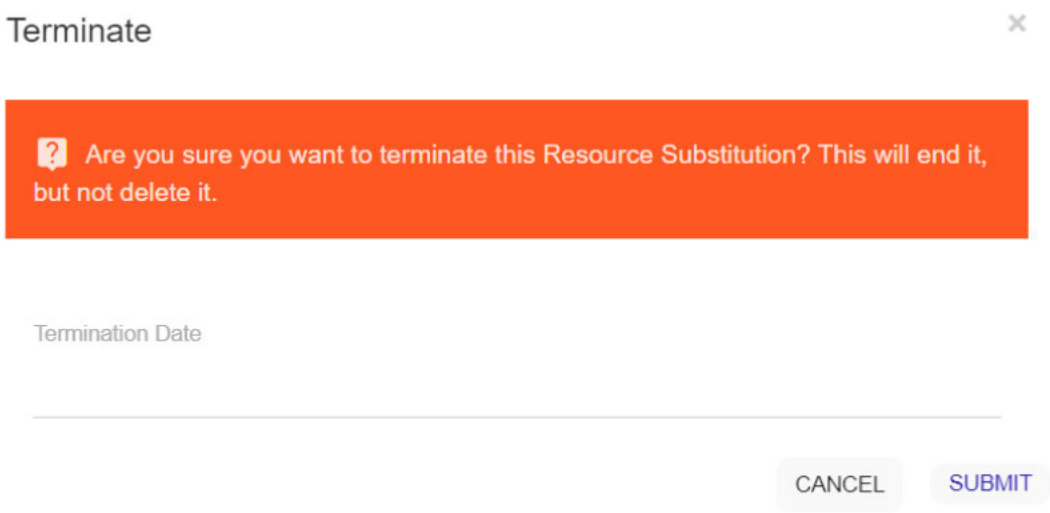
BPM-011-r28 updated and posted to MISO website

- BPM-011-r28 has been posted to MISO website with clarification to sections 6.4.3 – 6.4.7
- Updates are limited to ZRC Replacement and implementation and assessment of the 31-day rule

Updates to the MECT allowing ZRC Replacement Termination

- Resource Substitution defaults to the end of the season
  - Before the effective date, a new dropdown will allow MPs to delete the substitution
  - After the effective date, a new dropdown will allow MPs to terminate the ZRC replacement between the effective date and current date





Scheduling 31+ day Generator Outages and participation in the PRA

- For resources that have anticipated planned outages that last longer than 31 days in the next Planning Year, the following options are available
  - Straddle seasons, if the resource has a planned 50-day outage, having 25 at the end of one season, continuing for the other 25 days into the subsequent season
  - If the outage is long enough, the resource could plan the outage during one season and not offer into the PRA for that season (requires working with the IMM). During the time the resource is available in the season, they could provide ZRC replacement for other resources
  - Work with the IMM to factor in the 31-day penalty price into the offer for the PRA, which can exceed the FSRL limit ~$25-30/MW-day

31-day Outage Rule (1 of 2)

- MISO's Control Room Operations Window (CROW) includes the following 4 categories of out of service (OOS) and derates: Planned, Urgent, Emergency and Forced. For purposes of calculating CRNCCs, MISO will use CROW outages prioritized as Planned. In addition, all outages not prioritized as Planned in CROW, but that were: (1) known or reasonably known at the time of the PRA, or (2) were determined by the IMM to be incorrectly prioritized in CROW shall be included in calculation of the CRNCC. See BPM-008 and the CROW users guide for outage prioritization codes and definitions. must replace ZRCs or incur a CRNCC penalty cost.
- Capacity non-compliance charge as stated in section 6.4.7 of BPM-011-r28 is equal to the # of days greater than 31 that did not properly replace * # of ZRCs * (seasonal ACP + daily Zonal CONE)
  - For example. A 100 MW resource in LRZ5 for Summer 2023 ($10 ACP) that was on a planned outage for 35 days and did not replace any ZRCs would incur the following charges
    - 4 days * 100MW * (10 + 300.2) = $124,080
- The ZRC replacement and penalties are assessed and applied to the Market Participant who converts SAC to ZRCs

31-day Outage Rule (2 of 2)

- The 31-day rule will be implemented on an hourly basis as laid out in section 6.4.7 of BPM-011-r28 (31 days * 24 hours = 744hours)
- CROW has 4 outage types

Forced – already out at time of submission	Not counted
Emergency – 0 to 2 days in the future	Not counted
Urgent – 2 to 14 days in the future	Not counted*
Planned – 14 days + in the future	Counted

- The hours of planned outages across the season per resource will be summed up from most ZRCs to least ZRCs, the 31 days will apply to the most severe planned outage days and the remaining hours will be counted towards the penalty
- The penalty is assessed on a daily basis so the hours will be converted back to days and rounded down to the nearest day

*IMM and MISO will continue to review Urgent, Emergency and Forced outages to determine if they were known or reasonably known at the time of the PRA and if they should be counted towards the 31-day outage rule

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Exhibit 120
2024 OMS-MISO Survey

2024 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2024 OMS-MISO Survey

CORRECTIONS
Reposted 6/20/2024
Slide 11 PRM% Updated

June 20, 2024

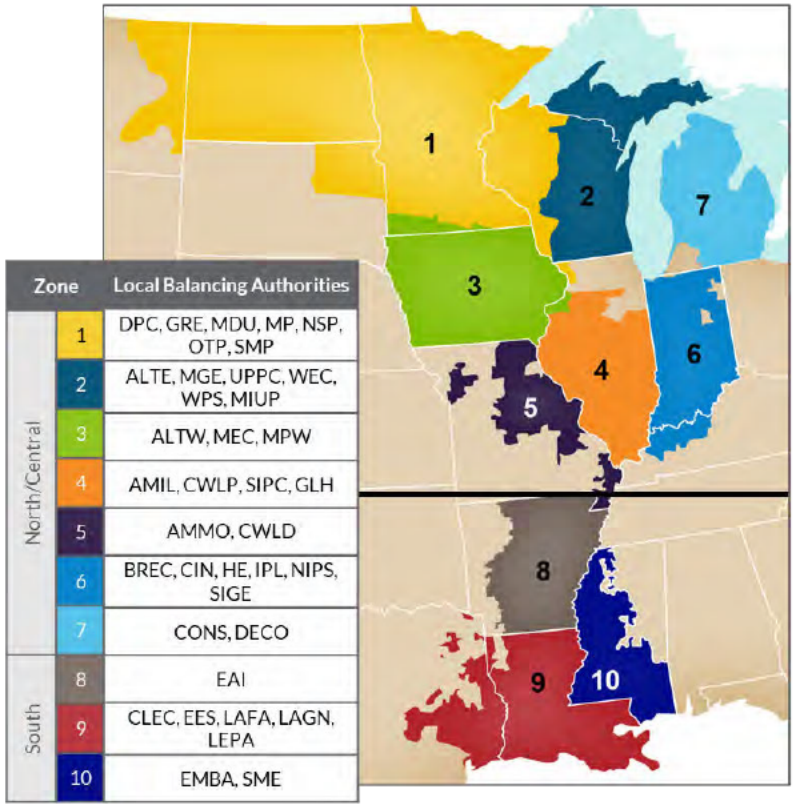
The 2024 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy in the MISO region

- Results indicate a potential surplus of 1.1 GW to a deficit of 2.7 GW for the summer of PY2025/26, depending on critical, yet uncertain, drivers such as the pace and quantity of new resource additions and projected resource retirements.
- Resource Adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements.
- Significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely addition of new resources.
- Recent reforms to MISO's resource adequacy construct will enhance MISO's ability to accurately assess the changing resource adequacy risks driven by extreme weather, the rapid growth of weather-dependent resources, and the retirement of dispatchable resources.
- Results highlight resource adequacy challenges in the MISO region and the need for continued collaboration between OMS, MISO, and its Members to maintain a reliable electricity system.

All presentation references to capacity indicate Seasonal Accredited Capacity (SAC)

The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

- The survey results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit.
- The survey considers that Load Serving Entities (LSEs) within each zone must have sufficient resources to meet load and required reserves.
- Surplus resources may be shared among LSEs with resource deficits to meet reserve requirements.



	Zone	Local Balancing Authorities
North/Central	1	DPC, GRE, MDU, MP, NSP, OTP, SMP
	2	ALTE, MGE, UPPC, WEC, WPS, MIUP
	3	ALTW, MEC, MPW
	4	AMIL, CWLP, SIPC, GLH
	5	AMMO, CWLD
	6	BREC, CIN, HE, IPL, NIPS, SIGE
	7	CONS, DECO
South	8	EAI
	9	CLEC, EES, LAFA, LAGN, LEPA
	10	EMBA, SME

This year's survey includes an updated baseline methodology to reflect the changing pace of new resource additions. Various scenarios for projected capacity and anticipated large spot-load additions across the MISO region are also included to highlight the increasing uncertainty and evolving risk.

90% of existing generation capacity participated in OMS-MISO Survey in 2024.

Additional factors can impact projected deficits or surpluses that are observed in the survey

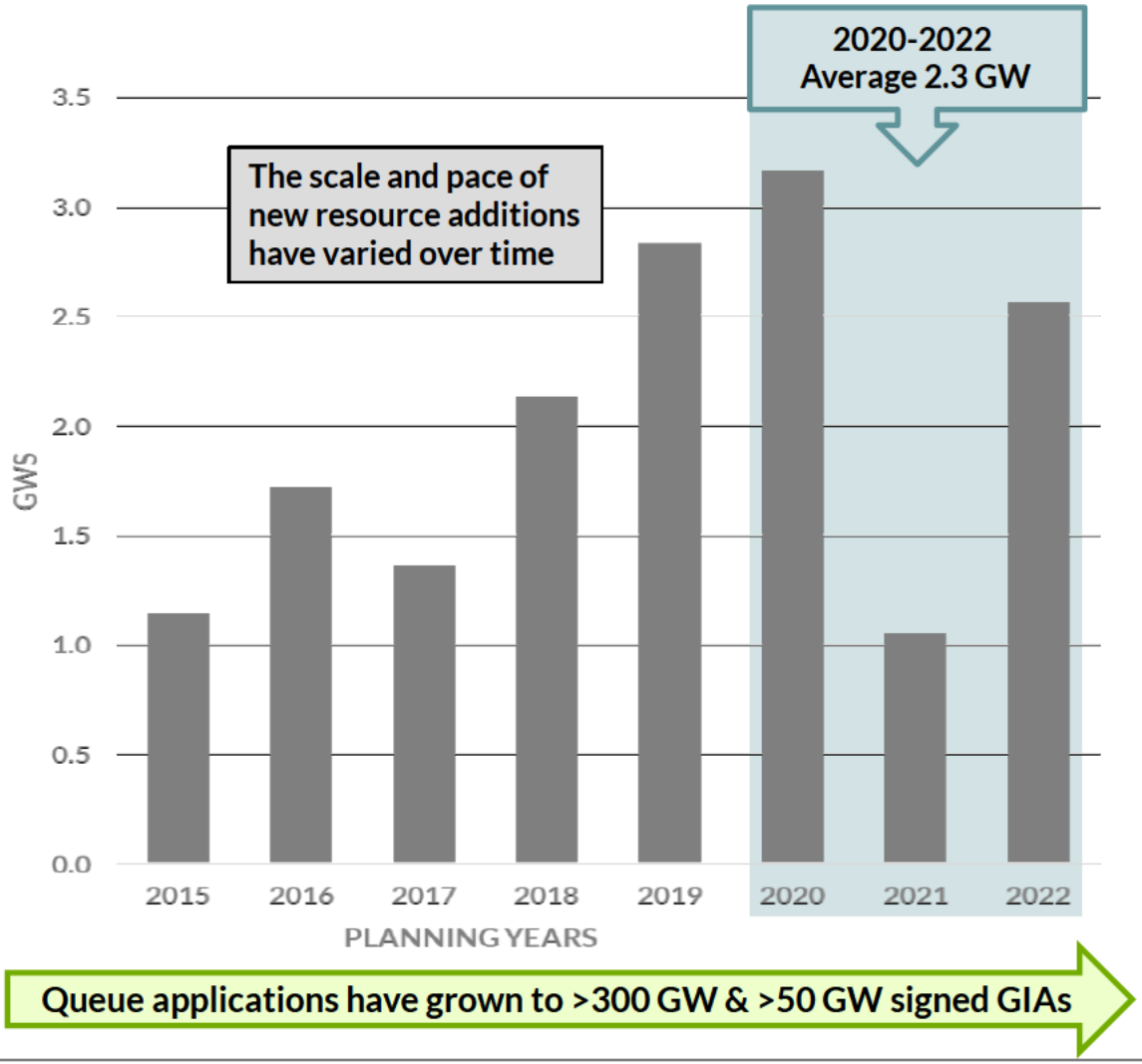
Downside Risks

- Continuing rapid pace of resource retirements
- EPA regulations further accelerating resource retirements
- Ongoing delays to capacity additions due to supply chain bottlenecks, permitting delays, and commercial challenges
- Continued queue challenges due to exceptionally large accumulated backlog and expectations for high quantities of future applications
- Higher load growth due to economic development and new, large spot-load additions (e.g., data centers and onshoring of manufacturing/new industrials), absent an improved ability to concurrently add new resources

Upside Possibilities

- Substantial new capacity enabled by the easing of supply chain bottlenecks, permitting constraints, and labor shortages
- Continued queue improvements to reduce speculative quantities and associated delays
- Market responses to local capacity deficits
- Improved price signals through market reforms, such as the Reliability Based Demand Curve, incentivizing additional capacity
- Improved ability to add new resources and support economic development and related new, large spot-load additions

Trends and market pressures related to new capacity additions suggest refinements are needed to better reflect uncertainty



Queue applications have grown to >300 GW & >50 GW signed GIAs

In the past, it was reasonable to use probability-adjusted estimates applied to quantities of projects in various phases of queue development.

That's no longer applicable due to the larger queue and constraints faced by projects with signed generation interconnection agreements (GIAs). The 2024 survey uses a range of estimates for new resource additions:

1. **Three-Year Historical Average:** based on the historical rate of additions per planning year*
2. **Alternative Projection:** based on MISO's updated timing estimates from interconnection customers with GIAs*

Note: 2023 data unavailable during time of analysis. Including 2023 projects would change the 3-year average to 2.2 GW.
**Based on Historical averages defined on slide 6*

Understanding Resource Categories

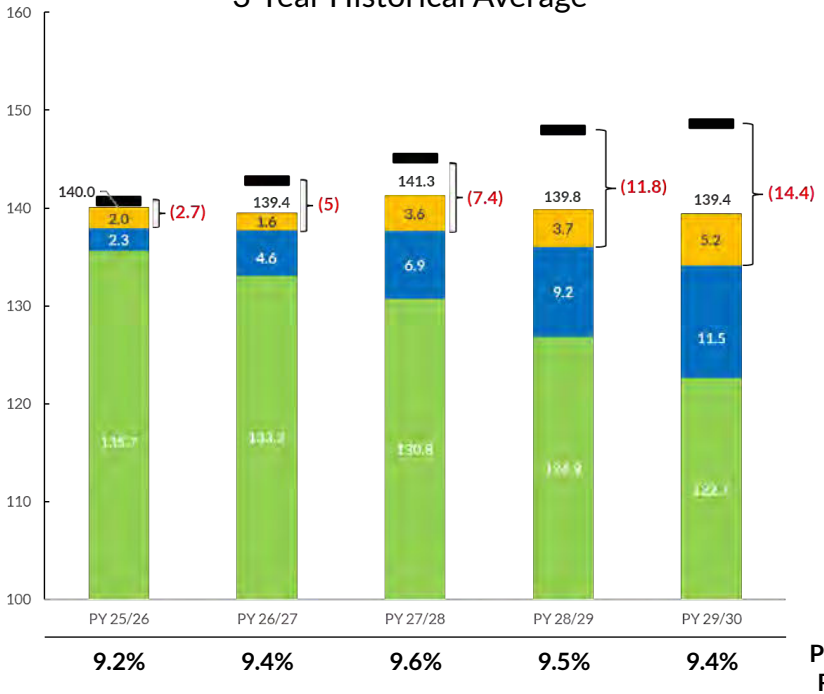
Resource Category	Past Practice	2024 Survey
Committed Capacity *Resources committed to serving MISO's load*	• Existing generation resources • Signed Generation Interconnection Agreement Projects • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR	• **Same, except does not include signed Generation Interconnection Agreement (GIA) projects (Signed GIA projects moved to 'Potential New')**
Potential New Capacity	• Projects in the MISO Generator Interconnection Queue adjusted for queue phase and related probabilities for projects reaching commercial operations • Assumes resources will **NOT** be used to meet PRMR	• **Using 3-Year Historical Average: Capacity addition based (2.3 GW/year) based on the average new capacity built in Planning Years 2020-2022** • **Using Alternative Projection: Informed by timing estimates from interconnection customers with signed GIA projects* (6.1 GW/year)** • **Assumes resources <u>WILL</u> be used to meet PRMR**
Potentially Unavailable Resources *May be available to serve MISO's load but may not have firm commitments*	• Indicated as Low Certainty in survey results by Market Participants • Includes potential retirements or suspensions • Assumes resources will **NOT** be used to meet PRMR	• **No Changes**

***MISO Alternative Projection**: Responses indicate 6.8GW can be built for PY 2025/26. MISO data shows 90% of GIAs get built.*
PRMR: Planning Reserve Margin Requirement

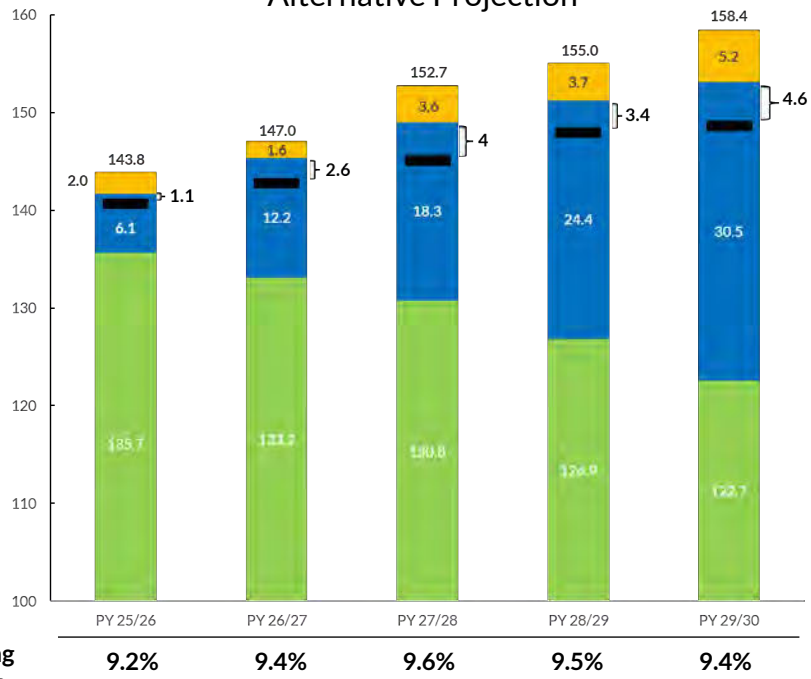
The 2024 OMS-MISO Survey illustrates a strong sensitivity to the pace of new capacity additions, with PY 2025/26 showing a range from a 2.7 GW deficit to a 1.1 GW surplus and widening thereafter

MISO Resource Adequacy Projection – Summer (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average*



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

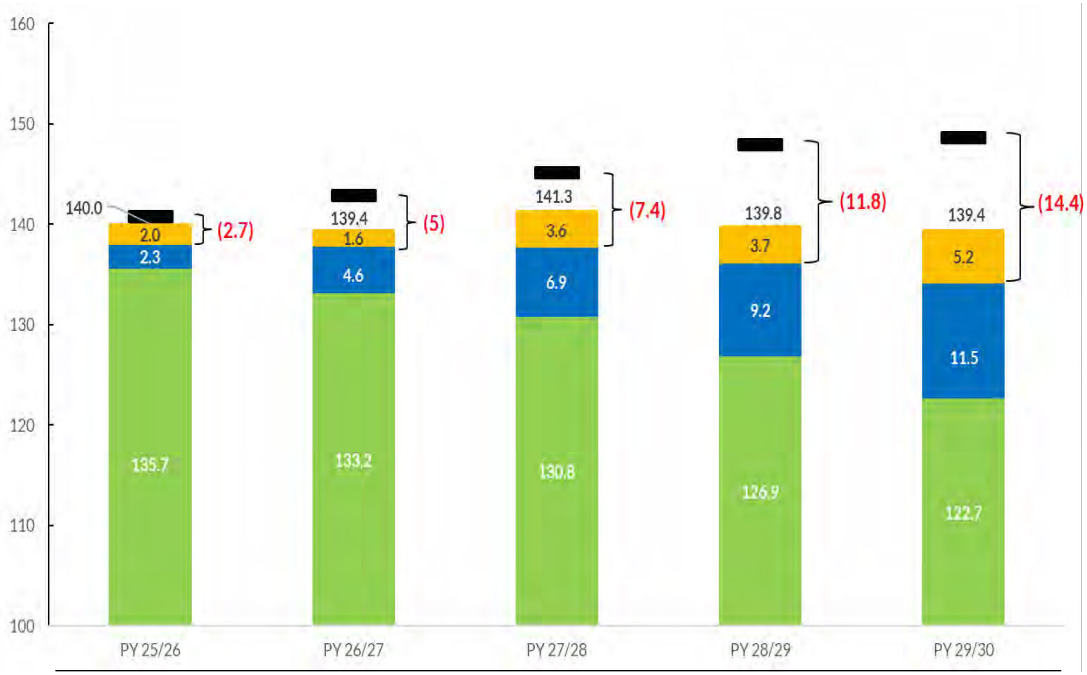
- Bracketed values indicate difference between Committed + Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using methods for potential New Capacity described on Slide 6*

Continued pace of retirements and pressures on generation development could potentially result in deficits as early as PY 2025/26

MISO Resource Adequacy Projection – Summer (GW)

*Assuming **2.3 GW/yr** of Potential New Capacity added*
3-Year Historical Average*



PRM% - Planning Reserve Margin	9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

Projection of 2.3 GW of new capacity per year derived from:

- Actual buildout over PYs 2020-2022
- Projected capacity buildout in line with historical rate
- Reflects impacts from COVID slowdown, such as continuing supply-chain bottlenecks, commercial uncertainty and permitting/labor delays

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
All references to capacity indicate Seasonal Accredited Capacity (SAC)
**Using Potential New Capacity as described on slide 6*

Favorable changes in development drivers could accelerate capacity additions necessary to cover projected growth

MISO Resource Adequacy Projection – Summer (GW)

*Assuming **6.1 GW/yr** of Potential New Capacity added*
Alternative Projection*



PRM% - Planning Reserve Margin

PY 25/26	PY 26/27	PY 27/28	PY 28/29	PY 29/30
9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

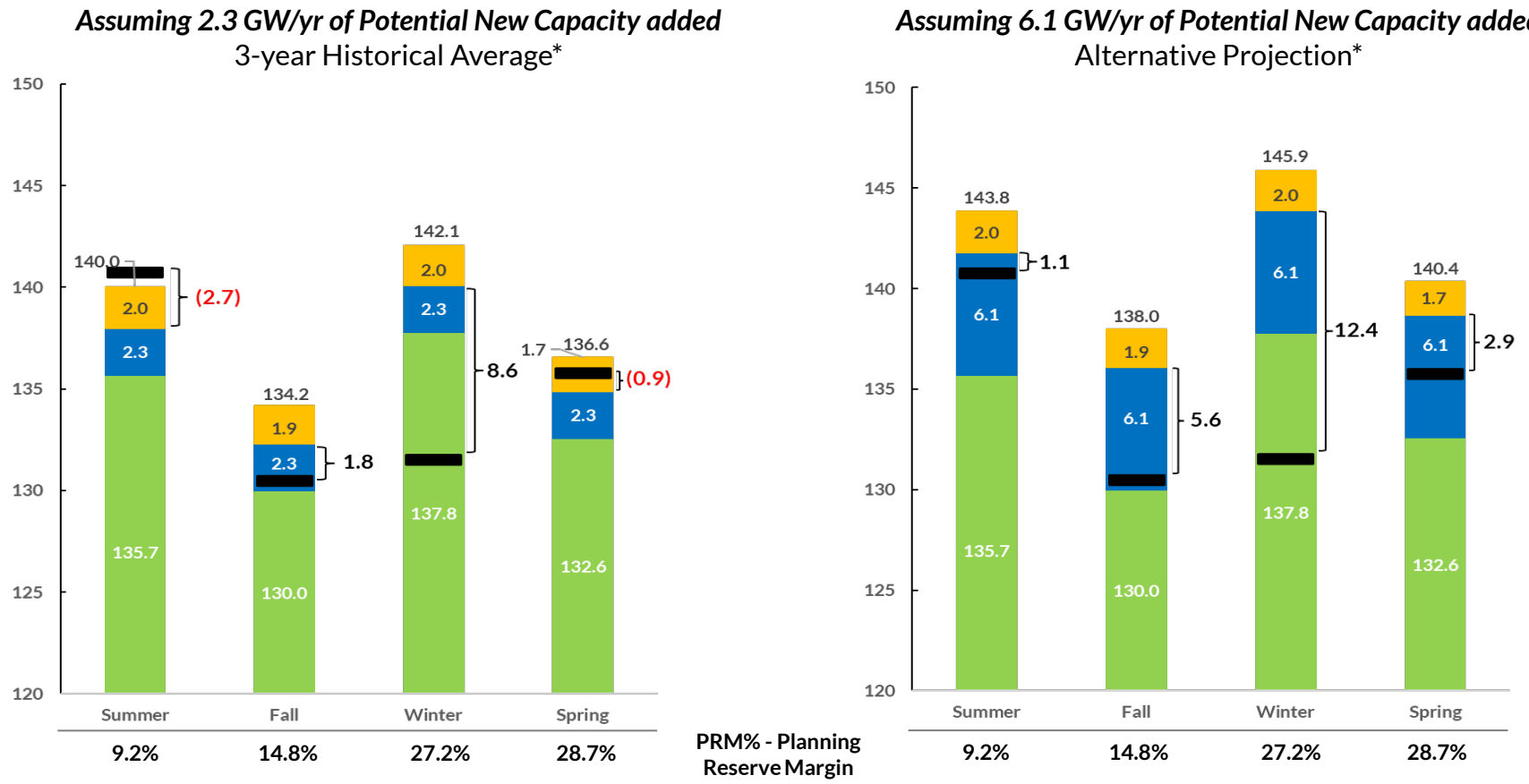
Projection of 6.1 GW of new capacity per year dependent upon:

- Easing of supply chain bottlenecks
- Reduced permitting-related delays
- Adequate supply of skilled labor
- Supportive commercial viability
- Continued queue improvements to reduce speculative quantities and associated delays

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
All references to capacity indicate Seasonal Accredited Capacity (SAC)
**Using Potential New Capacity as described on slide 6*

Seasonal comparison for PY 2025-26 shows the greatest risk in summer and spring

MISO Resource Adequacy Projection 2025/26 (GW)



Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

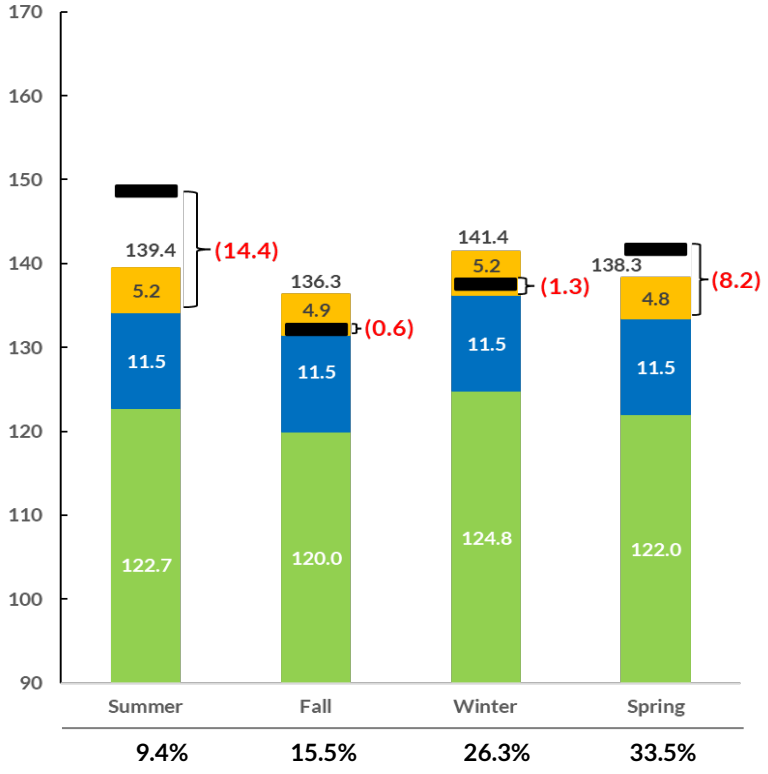
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

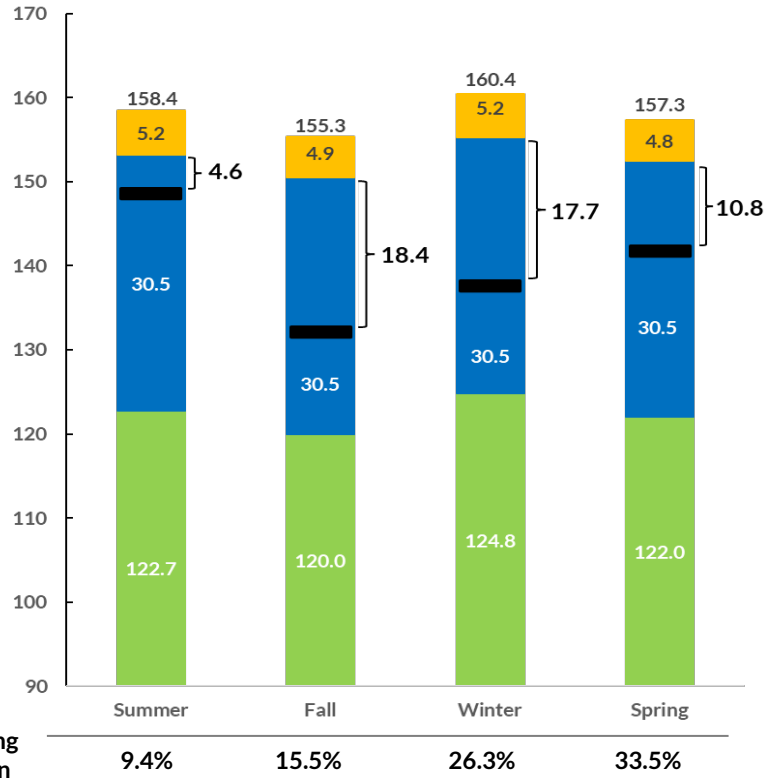
Projections for PY 2029/30 show increased reliance on new resources to meet PRMR

MISO Resource Adequacy Projection 2029/30 (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average*



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin

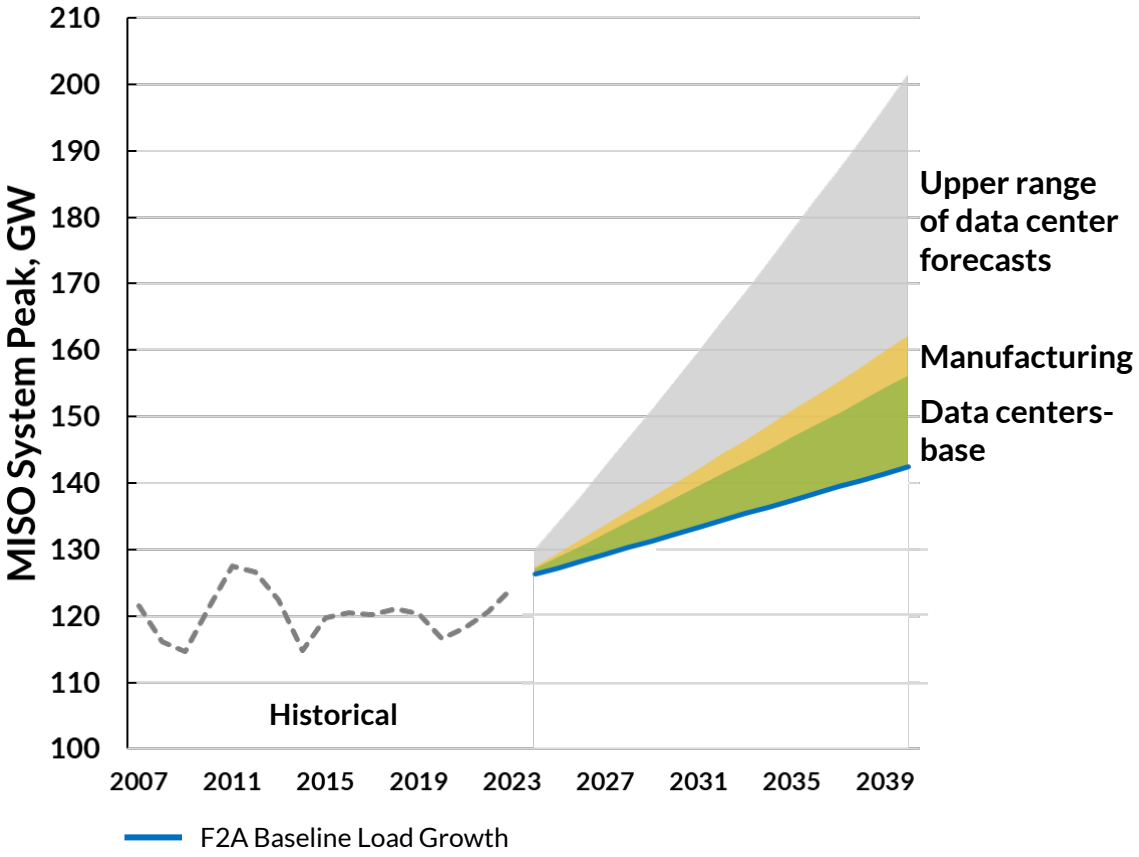
Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

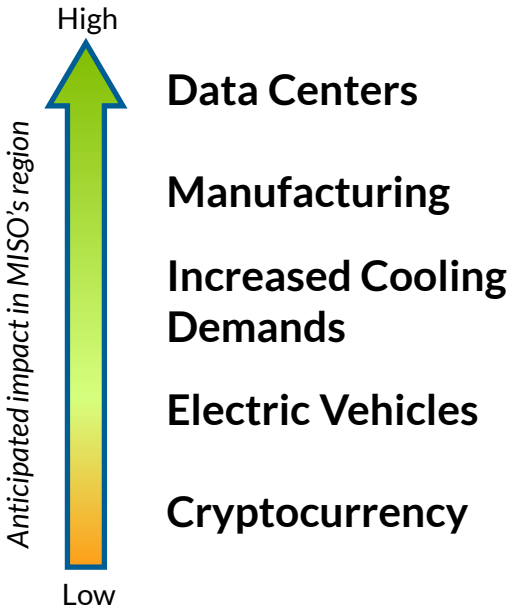
MISO's future long-term load forecasts will account for emerging digital demands, industrial expansion and climate changes

EPRI and Grid Strategies[1] anticipate manufacturing growth to favor MISO's service area



Note: *All figures shown are PRELIMINARY*

- Grid planners nearly *doubled* their 5-year peak load growth forecasts since last year
- MISO anticipates strong *long-term* load growth driven primarily by:



See appendix slide 31 with load forecast updates of other grid operators, potential new data centers in MISO and other commentary

1: https://www.epri.com/research/products/000000003002027930; https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

NEW: The 2024 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions



Illustrative Example: PY 2026/27 Using Three-Year Historical Average

PRMR based on a higher range of large spot-load additions

- Uses MISO Future 2A as starting point[1]
- Models higher load-growth scenario using data from third-party consultants based on aggressive buildout of large load spot additions[2]

PRMR considering large spot-load additions

- Uses MISO Future 2A as starting point[1]
- Models increased demand based on public announcements for proposed data centers and manufacturing facilities within the MISO region[2]

PRMR based on LSE submitted load forecast

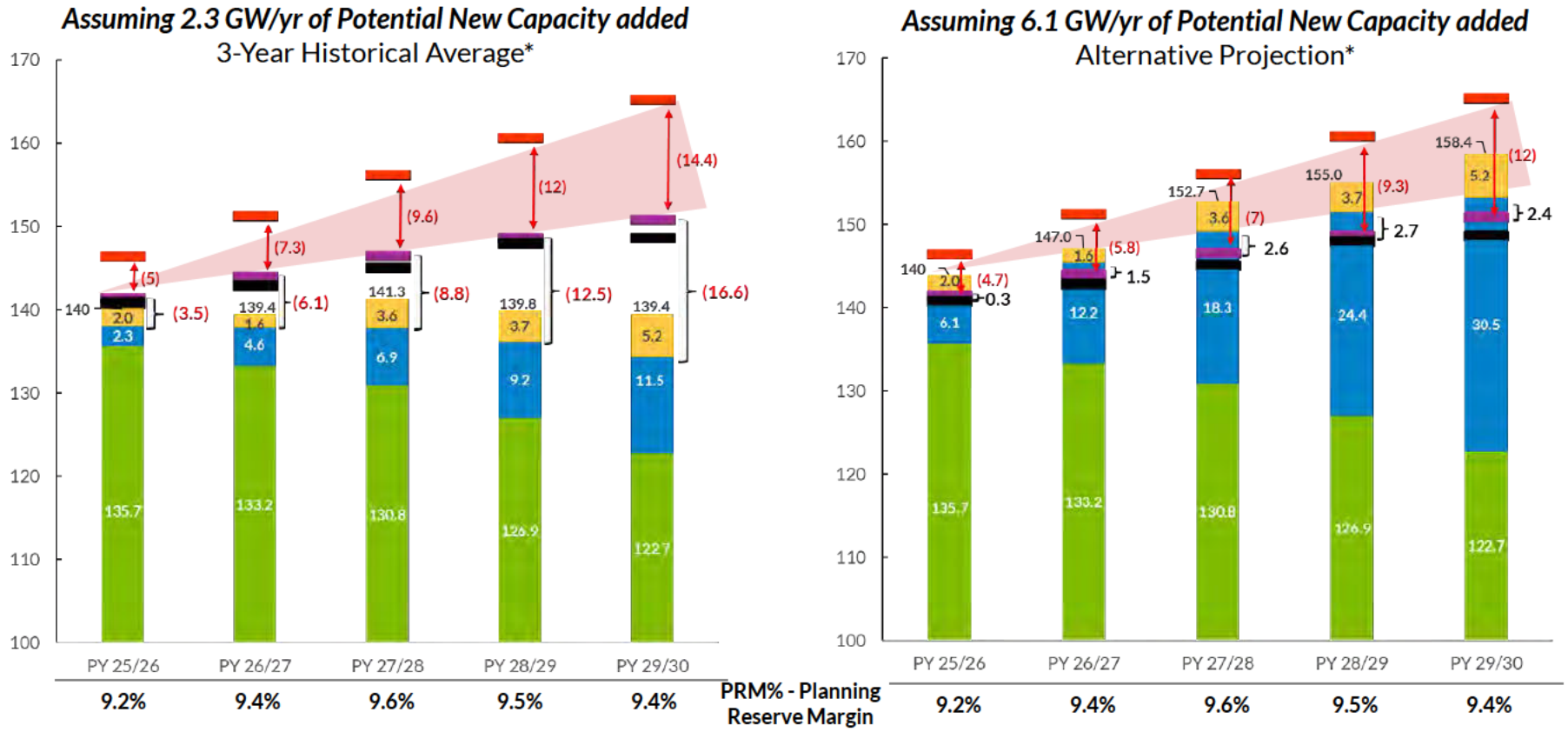
- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO posted Coincidence Factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2024/25 LOLE Study

[1] https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf, [2] *See slides 12 & 31 for more information*

PRMR: Planning Reserve Margin Requirement LSE: Load Serving Entity LOLE: Loss of Load Expectation

Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

MISO Resource Adequacy Projection – Summer (GW)



- Bracketed values indicate difference between Committed + Projected New Capacity and Projected PRMR with large spot-load additions
- Red arrow values indicate the additional potential deficit with high-range large load growth case
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's proposed resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

MISO's proposed accreditation reforms, on file at FERC and targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.

See Resource Accreditation White Paper, published March 2024:
https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf

The 2024 Survey shows that the near-term resource decisions made by utilities, regulators, MISO and its Members will determine whether the region's resources remain adequate

- Continued collaboration between OMS and MISO is necessary to maintain a reliable electricity system.
- The survey shows a range of potential resource adequacy outcomes, reinforcing near-term risks and illustrating key uncertainties impacting resource adequacy in the MISO region.
- Immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements.
- MISO's reforms under the Reliability Imperative are timely and responsive to the drivers contributing to resource adequacy challenges.
    - Implemented: Seasonal construct and thermal accreditation
    - Filed at FERC: 1) Reliability-Based Demand Curve, 2) resource accreditation
    - Ongoing reforms: 1) Load Modifying Resource accreditation, 2) Resource adequacy risk modeling improvements, 3) Attributes Roadmap, 4) LRTP, 5) JTIQ, 6) Queue Reforms

Appendix

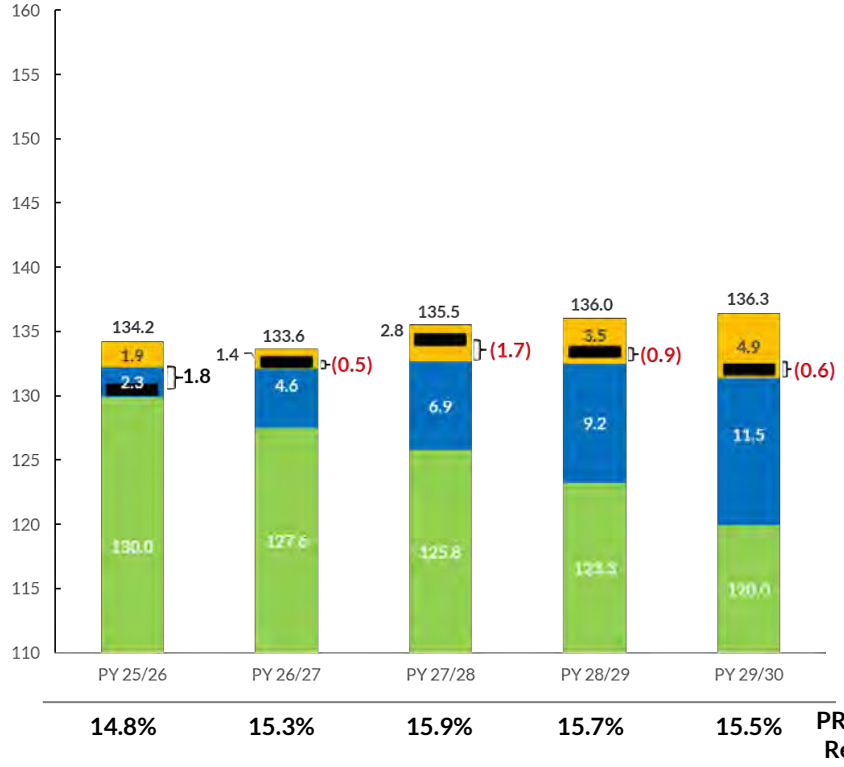
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Fall capacity ranges from 1.8 GWs to 5.6 GWs surplus in the prompt year

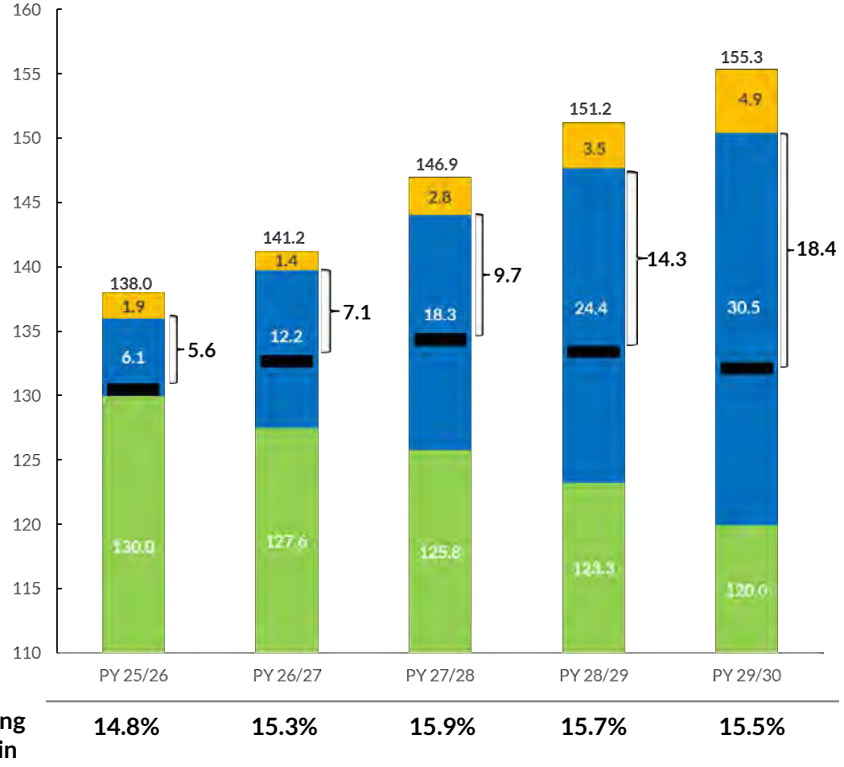
MISO Resource Adequacy Projection – Fall (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average*



PRM% - Planning Reserve Margin

Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

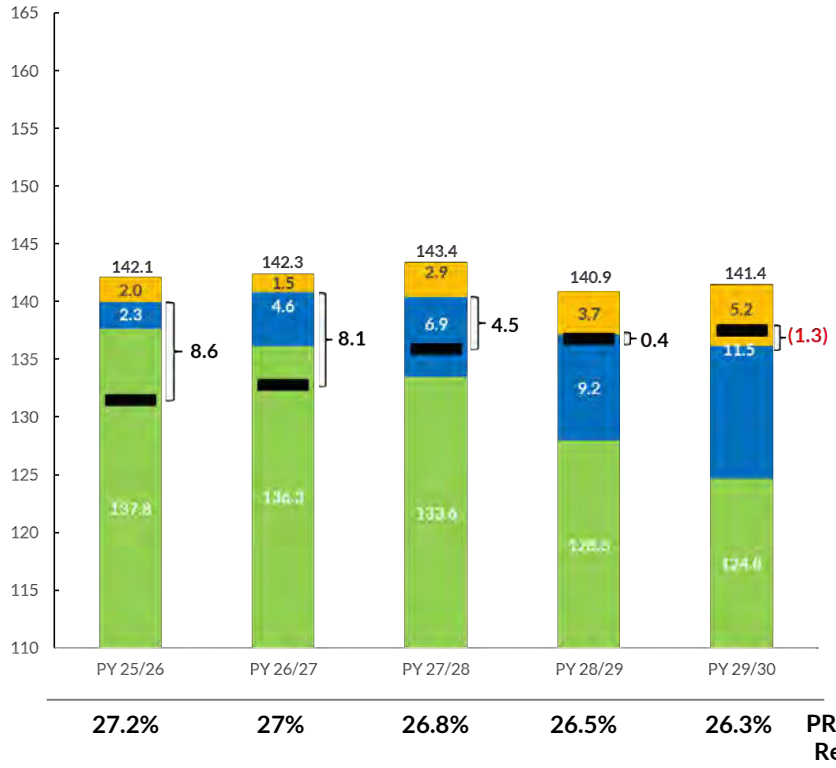
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart
- Fall demand and PRMR calculated by using summer and winter demand forecast percent change seen year-over-year since out year Non- Coincident Peak Forecast (NCPF) is not submitted for out years for fall and spring

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

Winter capacity ranges from 8.6 GWs to 12.4 GWs surplus in the prompt year

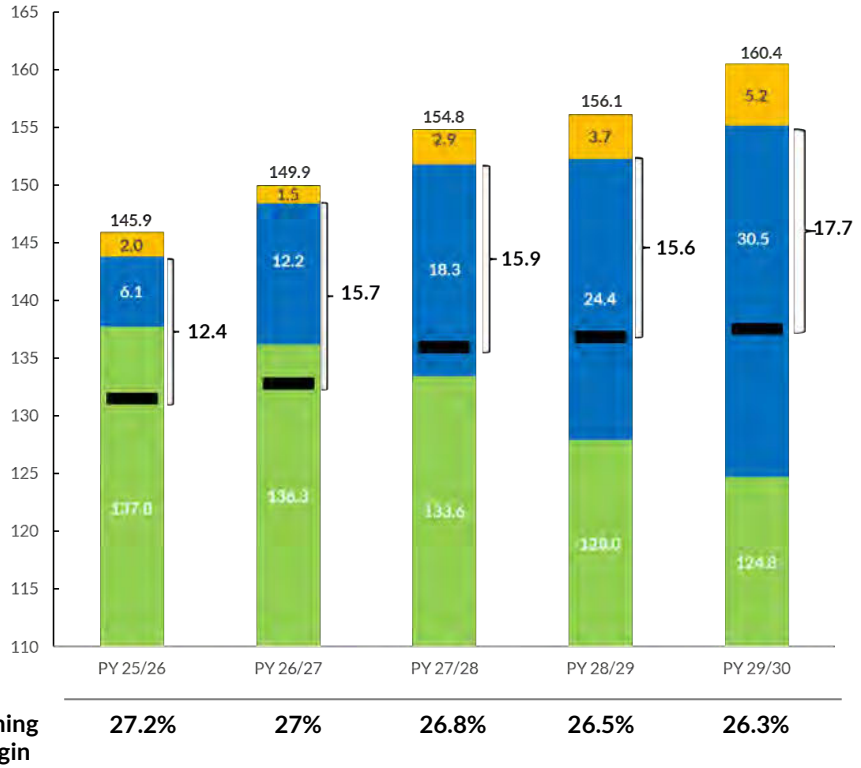
MISO Resource Adequacy Projection – Winter (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



27.2%	27%	26.8%	26.5%	26.3%	PRM% - Planning Reserve Margin

Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



27.2%	27%	26.8%	26.5%	26.3%

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

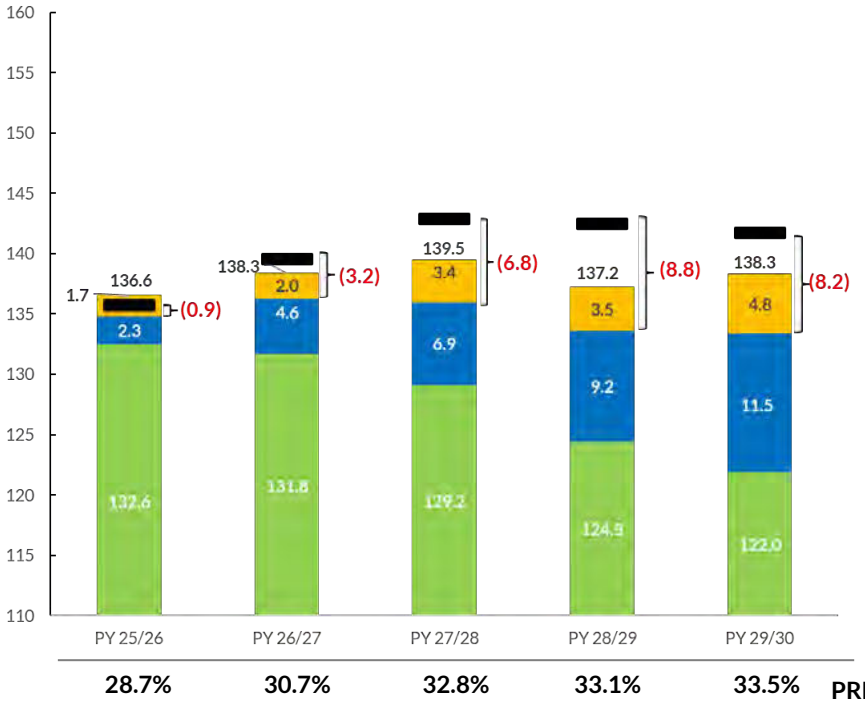
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

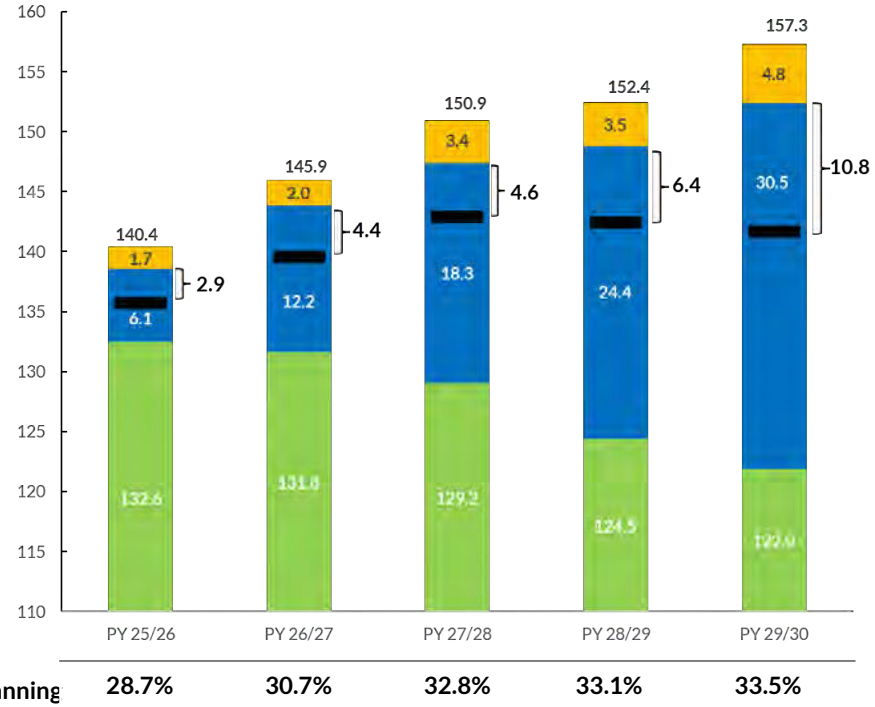
Spring capacity ranges from 0.9 GWs deficit to 2.9 GWS surplus in the prompt year

MISO Resource Adequacy Projection – Spring (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin	28.7%	30.7%	32.8%	33.1%	33.5%
	28.7%	30.7%	32.8%	33.1%	33.5%

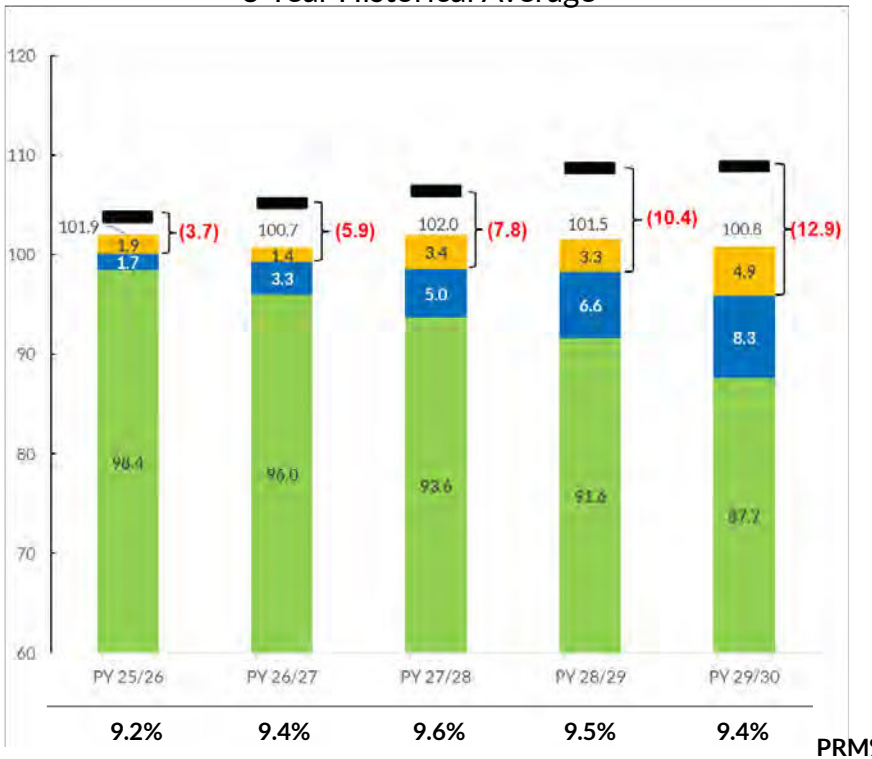
Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart
- Spring demand and therefore PRMR is calculated by using Summer and Winter demand forecast percent change seen year over year since out year NCPF is not submitted for out years for Fall and Spring

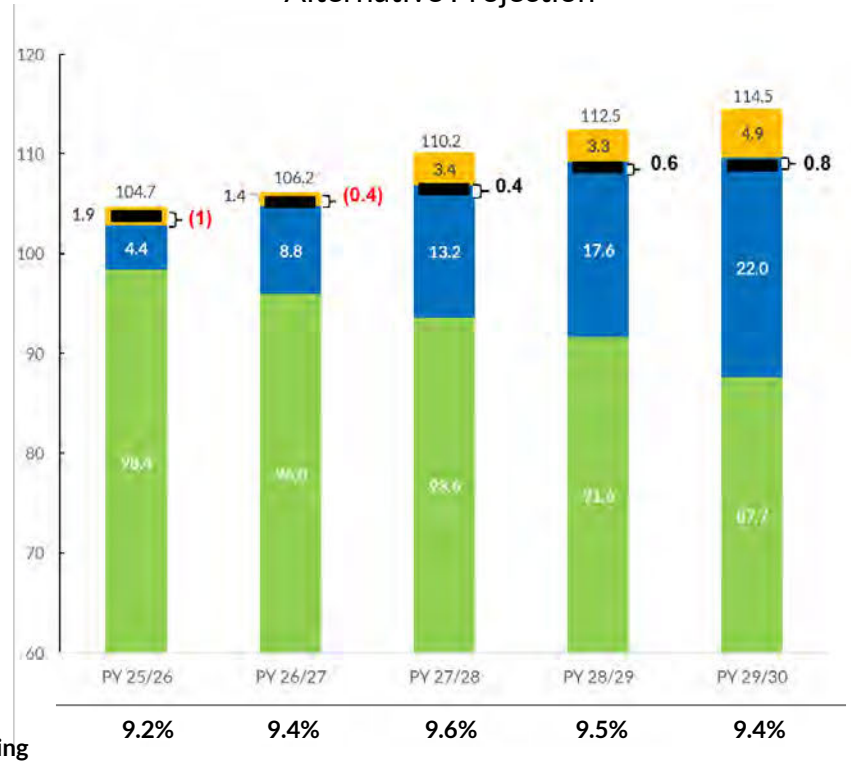
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

The North/Central subregion capacity for Summer ranges from 3.7 GWs to 1 GW deficit in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



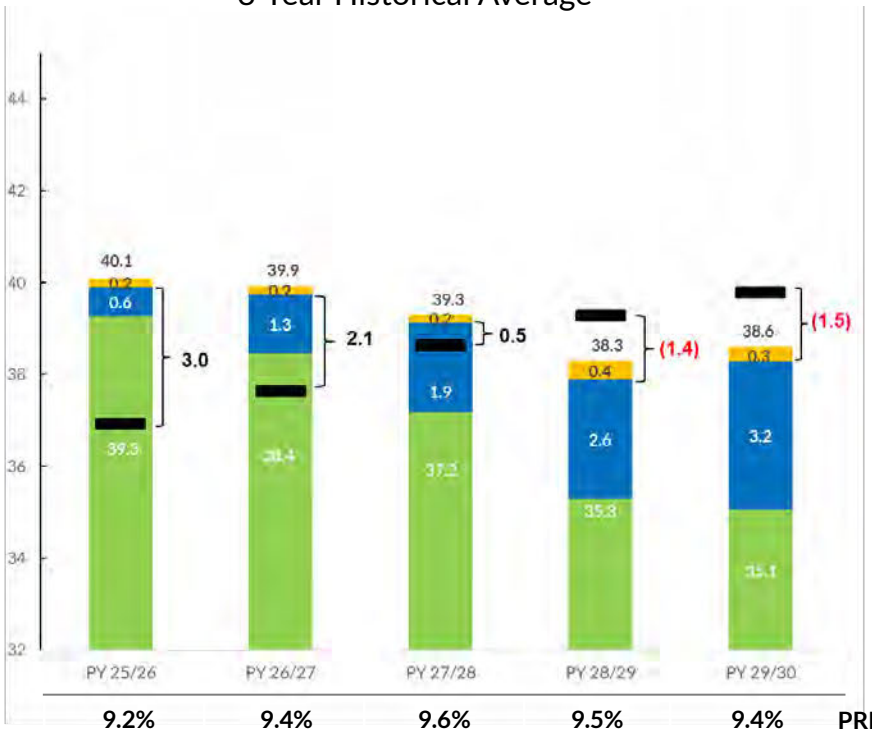
PRM% - Planning Reserve Margin

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

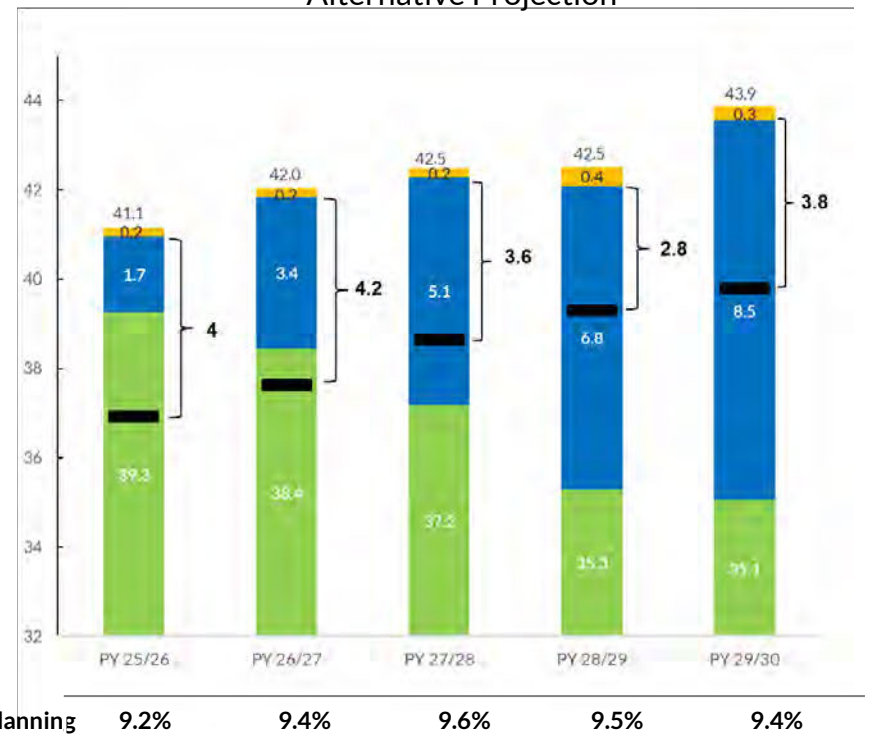
Using Potential New Capacity as described on slide 6
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

The South subregion capacity for Summer ranges from 3 GWs to 4 GWs of surplus in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin	9.2%	9.4%	9.6%	9.5%	9.4%	9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

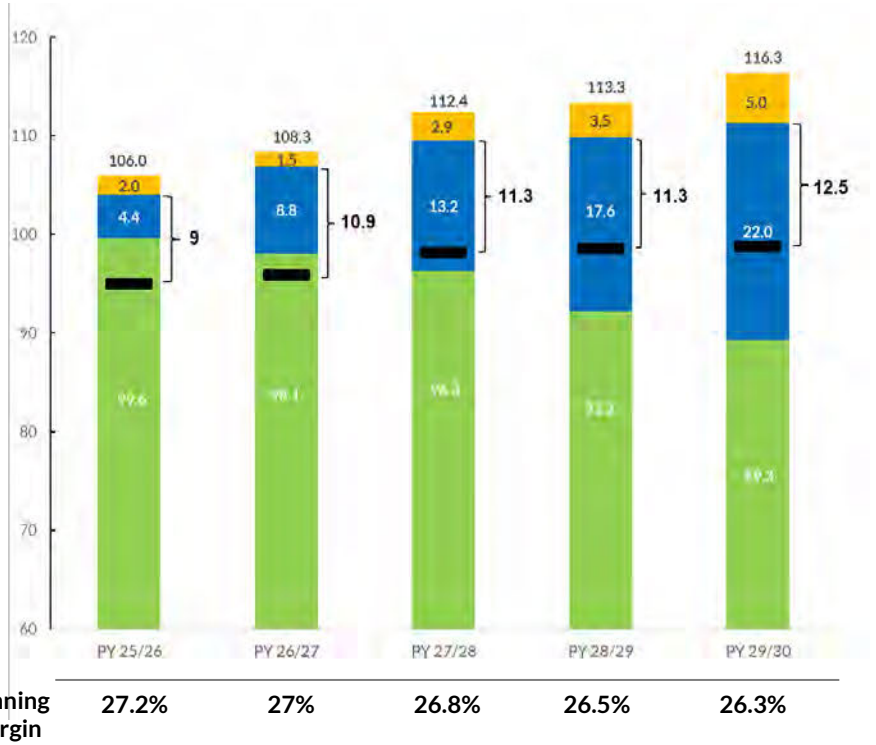
Using Potential New Capacity as described on slide 6
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

The North/Central subregion capacity for Winter ranges from 6.3 GWs to 9 GWs of surplus in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



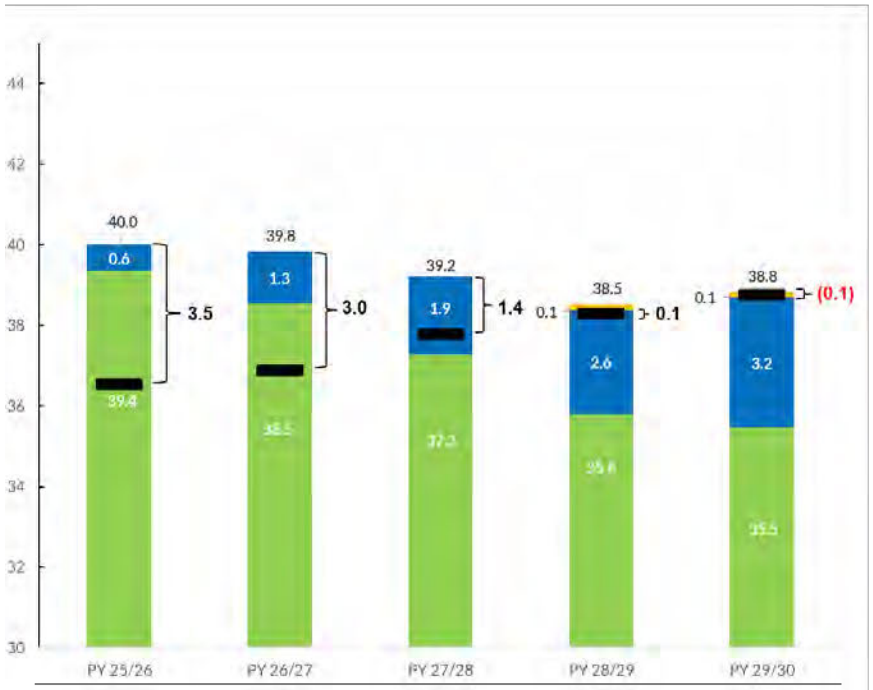
27.2%	27%	26.8%	26.5%	26.3%	PRM% - Planning Reserve Margin	27.2%	27%	26.8%	26.5%	26.3%

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

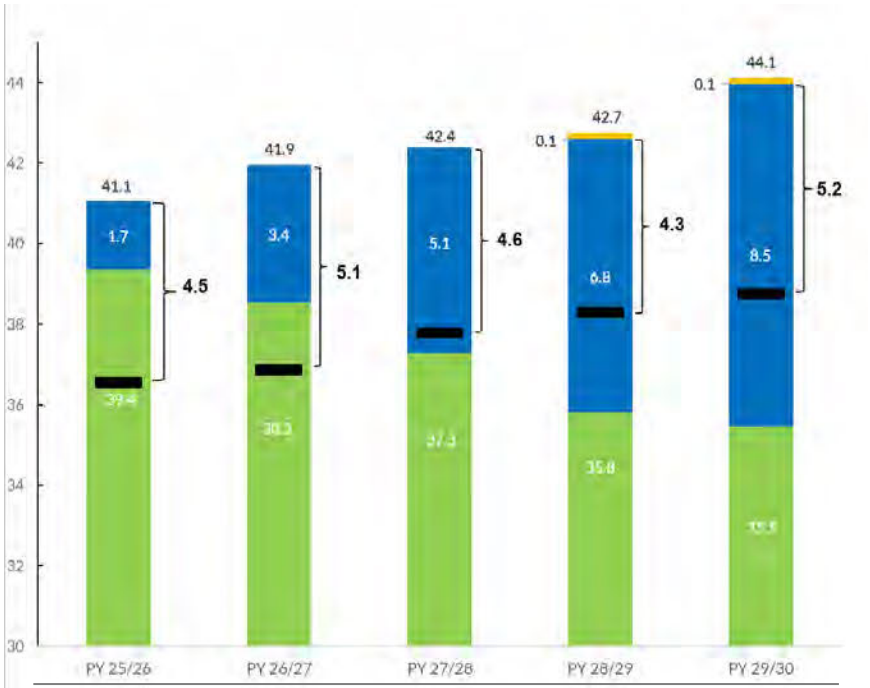
*Using Potential New Capacity as described on slide 6
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

The South subregion capacity for Winter ranges from 3.5 GWs to 4.5 GWs of surplus in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



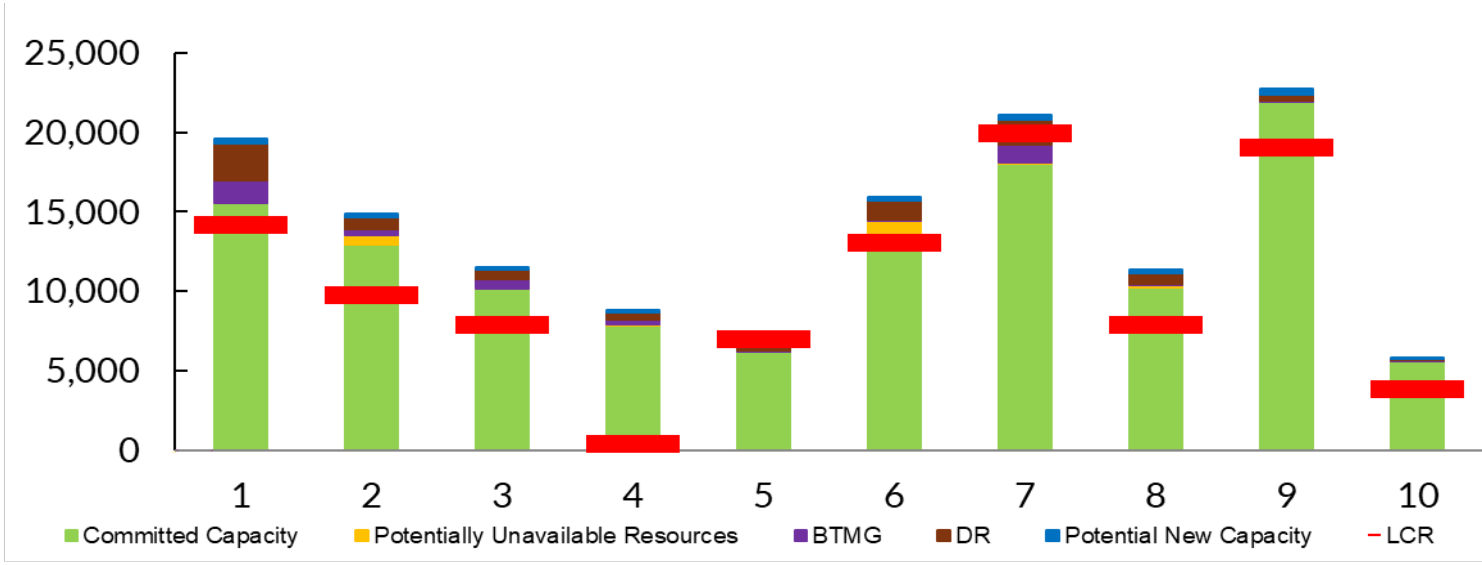
PRM% - Planning Reserve Margin	27.2%	27%	26.8%	26.5%	26.3%
	27.2%	27%	26.8%	26.5%	26.3%

Projected PRMR with LSE forecast
Potentia y Unavai ab e Resources
Potentia New Capacity
Committed Capacity

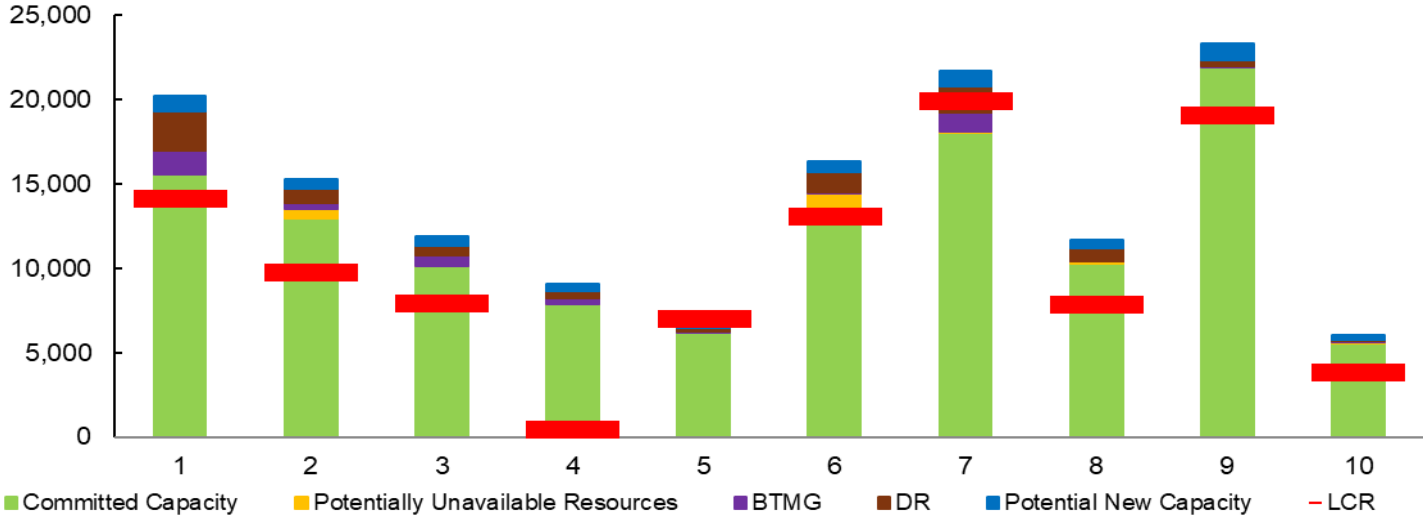
*Using Potential New Capacity as described on slide 6
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

Summer PY 2025/26 Load Clearing Requirement (LCR) by zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

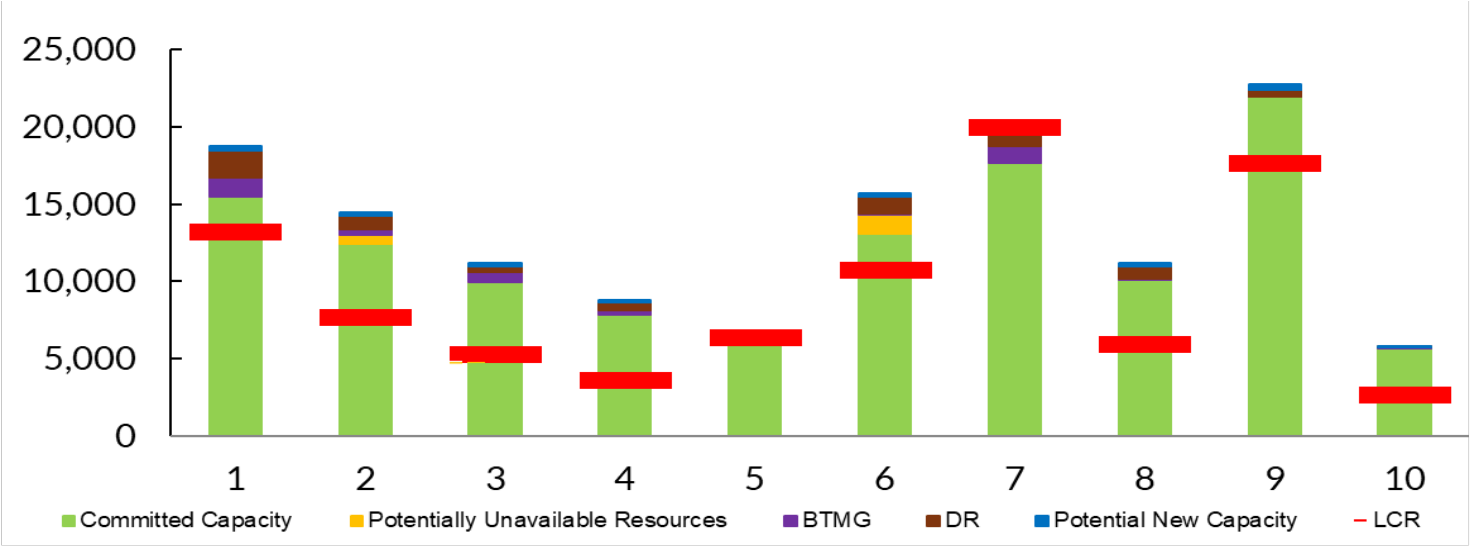


*Using Potential New Capacity as described on slide 6

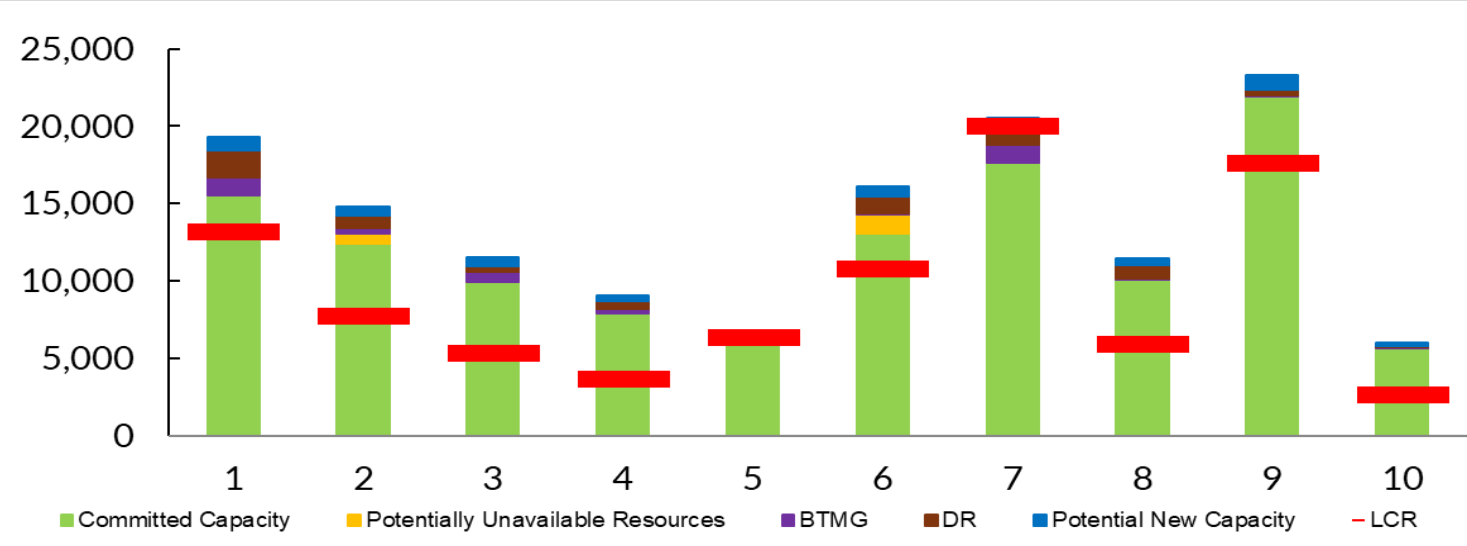
Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Fall PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

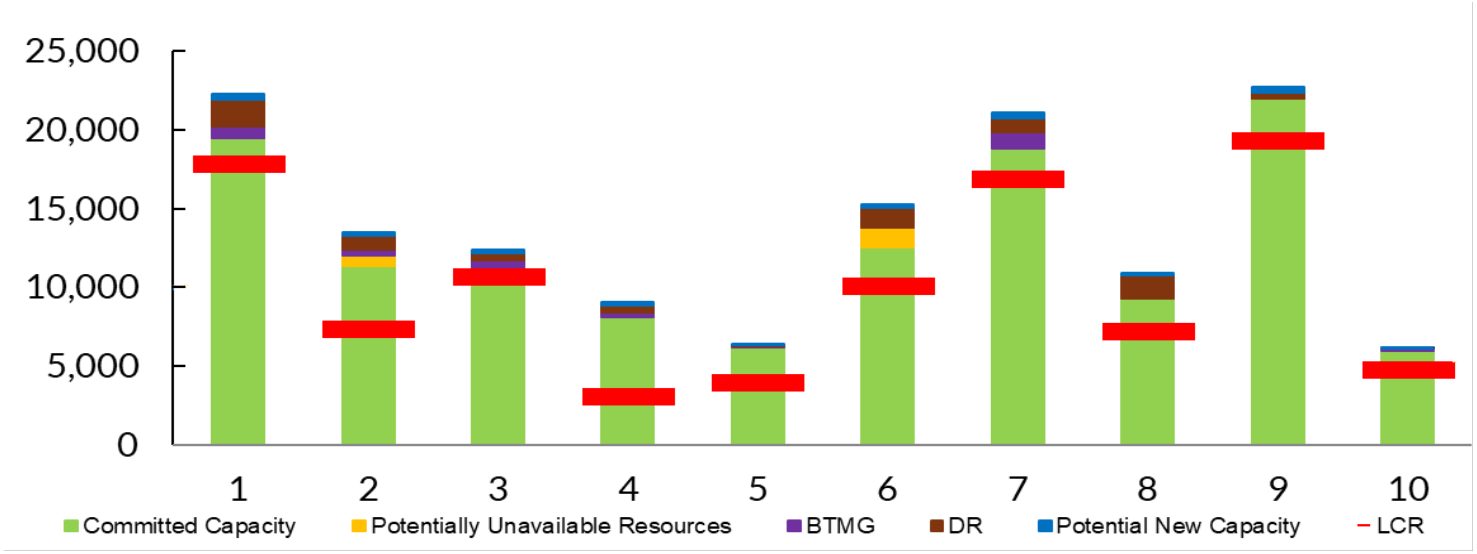


*Using Potential New Capacity as described on slide 6

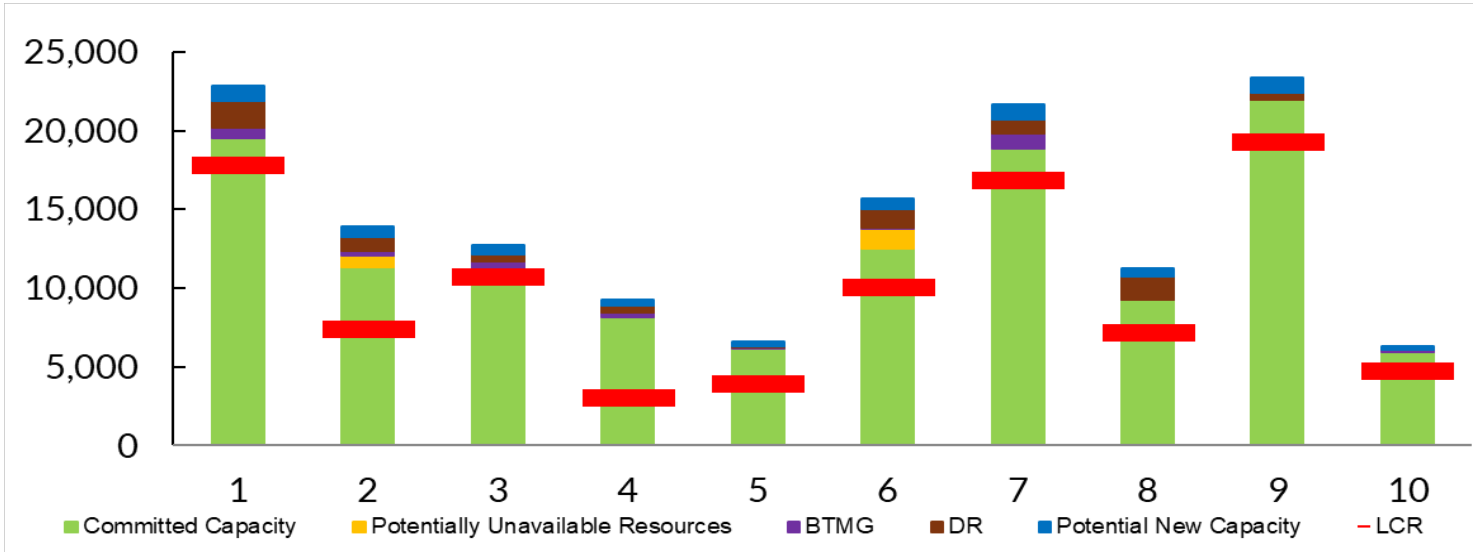
Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Winter PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

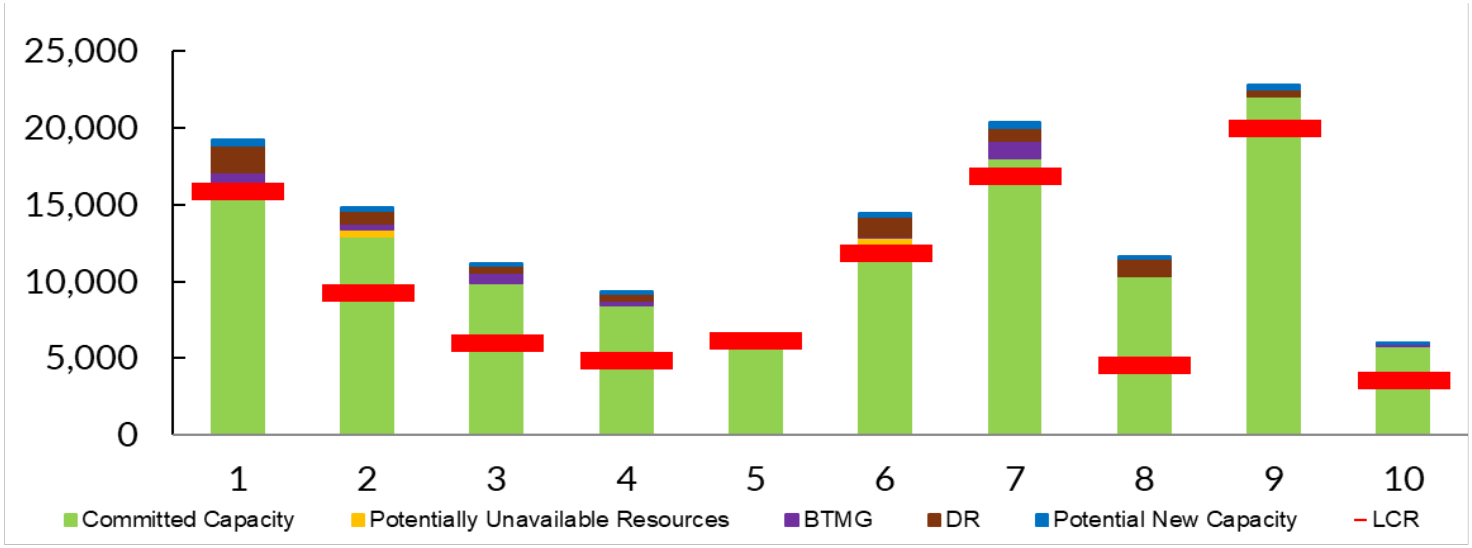


*Using Potential New Capacity as described on slide 6

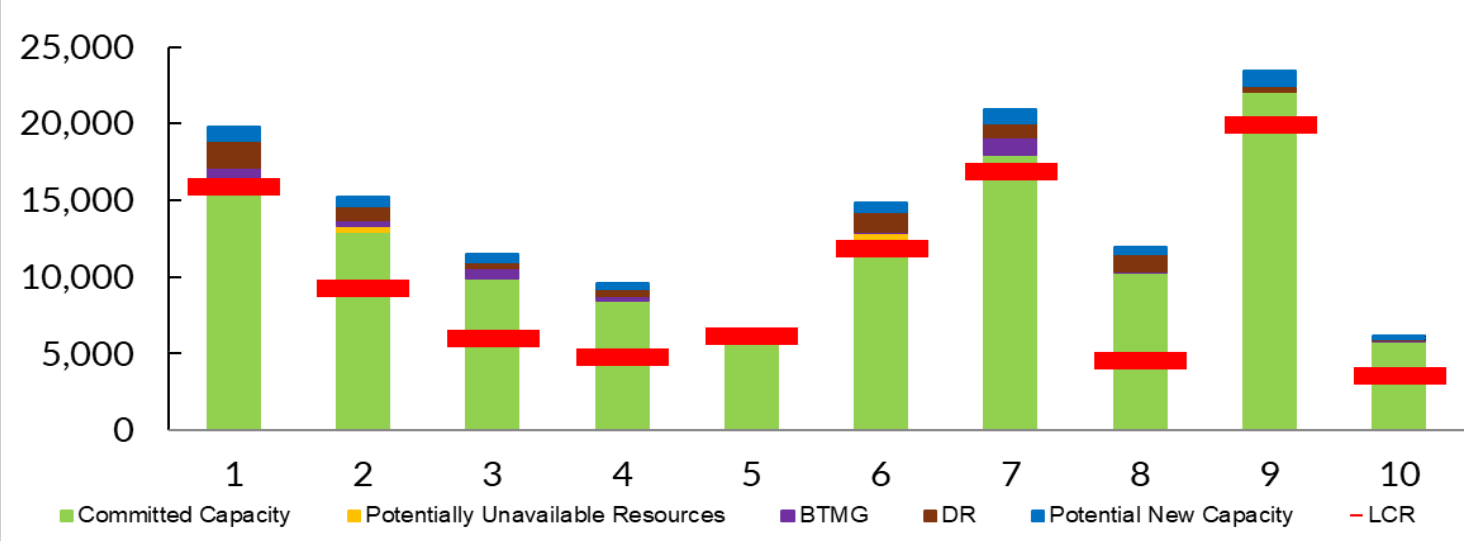
Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Spring PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



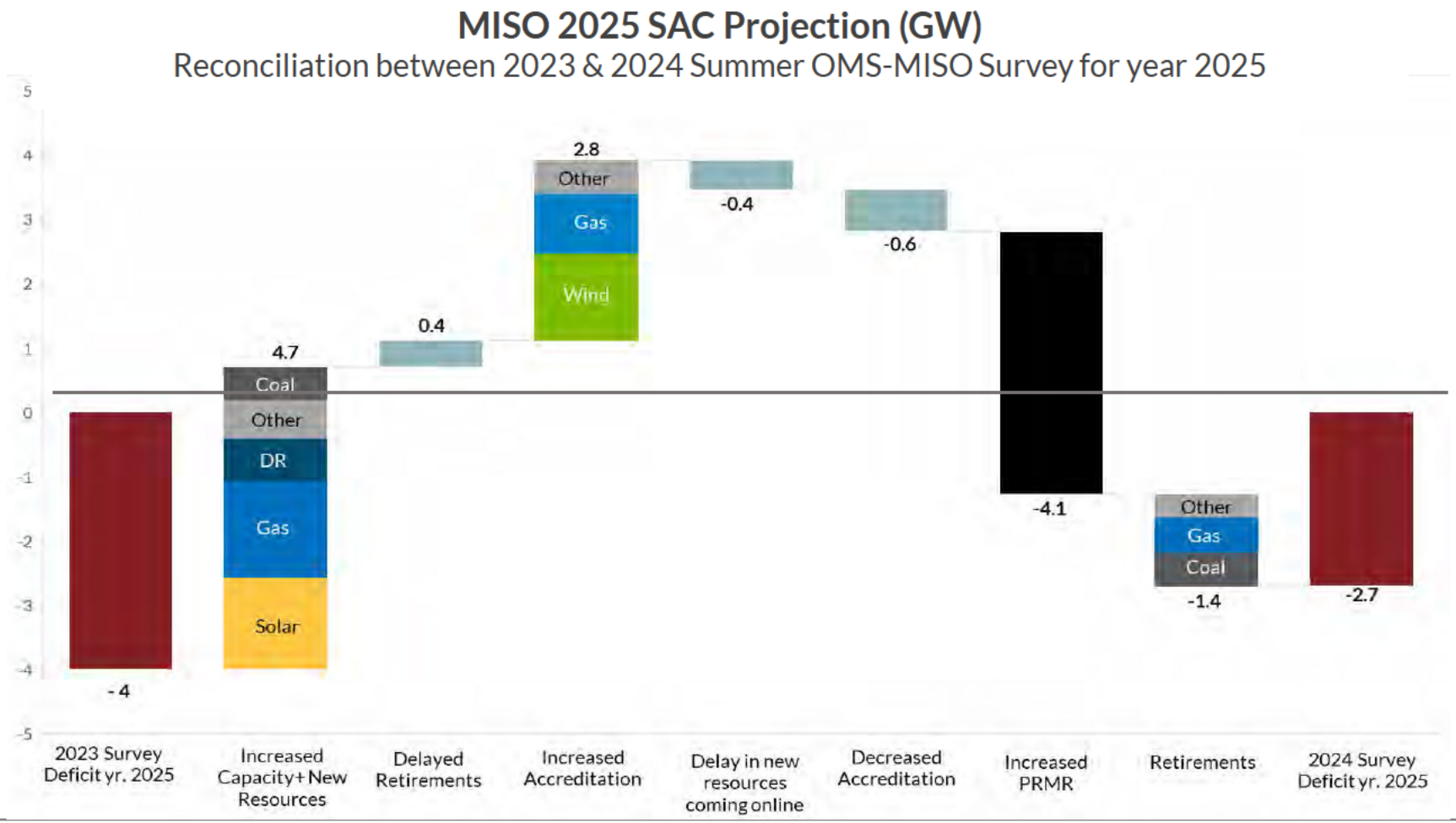
PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*



*Using Potential New Capacity as described on slide 6

Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Year-over-year, the OMS-MISO Survey results show a decreased deficit due to increased response/new resources and increased accreditation, but a deficit remains largely driven by an increased Planning Reserve Margin Requirement



Higher load forecast included in 'Increased PRMR (Planning Reserve Margin Requirement)'
Other in 'Increased Response +New Resources': Wind, Battery, Hydro, and Oil
Other in 'Increased Accreditation' and Retirements: Other-Gas(CU ft), Water, Wood, Waste Heat

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 121
Witmeier 2025 ERAS Testimony

TAB C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

June 6, 2025

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined MISO in 2003 after graduating from Purdue University with a bachelor's degree in electrical engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time, I worked as a North American Electric Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position where I have remained for the past five years.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.

A. As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "MISO Tariff").[1] I oversee MISO's generation interconnection queue, including the negotiation and execution of Generator Interconnection Agreements ("GIAs"), which are based on MISO's *pro forma* GIA set forth in Appendix 6 of the GIP. I also oversee the group that manages and processes generation retirement, generator replacement, and Surplus Interconnection Service requests for generators connected to MISO's Transmission System. I have been directly involved in the preparation and development of the current proposals.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony in a number of proceedings before the Commission. The most recent testimonies are as follows:

- In March 2025, I provided testimony in Docket No. ER25-1674-000 to support MISO's original Expedited Resource Addition Study ("ERAS") proposal.
- In November 2024, I provided testimony in Docket No. ER25-507-000 to support MISO's generator interconnection cap proposal.

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

- In August 2024, I provided testimonies supporting the JOA and MISO Tariff revisions implementing the JTIQ initiative in Docket No. ER24-2797-000 and ER24-2871-000.
- In November 2023, I sponsored testimony in Docket Nos. ER24-340-000 and ER24-341-000 supporting a package of reforms of MISO's generator interconnection process.
- In December 2021, I submitted testimony in Docket No. ER22-661-000 on issues relating to MISO's generator queue reform and resource utilization.

II. OVERVIEW AND PURPOSE OF TESTIMONY

Q. ARE YOU SUBMITTING YOUR TESTIMONY ON BEHALF OF MISO?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the updated Tariff revisions that MISO is submitting in this docket to file certain urgent improvements to the GIP. MISO is proposing the creation of a new process—the Expedited Resource Addition Study ("ERAS")—to facilitate the addition of projects to address certain near-term resource adequacy and reliability needs. This process will be separate from MISO's generator interconnection queue process, which is referred to as the Definitive Planning Phase ("DPP") process. As further discussed below, while MISO has been actively improving the efficiency of its generator interconnection queue with recent reforms, it will take several years for the impact of these changes to be fully realized and for MISO to reduce queue processing time to an approximately one-year timeframe. MISO has refined its original ERAS process, which will be more fully explained and addressed in my testimony.

Q. CAN YOU BRIEFLY EXPLAIN THE REFINEMENTS THAT WERE MADE TO MISO'S ORIGINAL ERAS PROPOSAL?

A. Yes. At a high level, MISO is now implementing a cap on ERAS projects to 68 total with carve outs for a maximum of 8 projects to serve retail choice load and a maximum of 10 projects from Independent Power Producers ("IPPs"). MISO is also implementing a requirement to only study 10 projects per ERAS Quarterly Study cycle.[2] In addition to the cap, MISO is changing the Relevant Electric Retail Rate Authority ("RERRA") notification requirement to a RERRA verification so that the ERAS project will be more closely targeted to a resource adequacy and/or reliability need in the RERRA's footprint. MISO is also limiting proposed ERAS project's interconnection service to 150% of the identified MW need, is requiring the project to be in the same Local Resource Zone ("LRZ") as the load need it is addressing (unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA), and is now requiring additional information in the ERAS Interconnection Request application. Finally, MISO has proposed tariff language to incorporate the retail states into the ERAS process. In the rest of my testimony, I go into further detail and background on these refinements.

Q. HOW DO THESE FILINGS RELATE TO MISO'S COMPLIANCE OBLIGATIONS UNDER ORDER NO. 2023/2023-A?

A. At the time of this submission, MISO submitted its Order No. 2023-2023-A compliance filings pursuant to the independent entity variation requirements set forth in Order Nos.

[2] MISO is requiring that projects proposed by IPPs must be with entities other than Load Serving Entities ("LSEs").

2003 and 2023.[3] If the Commission accepts the proposed revisions, they will become part of the MISO Tariff.

Q. IS MISO REQUESTING AN INDIVIDUAL ENTITY VARIATION?

A. Yes. ERAS is a new and temporary process that is intended to exist separately from MISO's DPP cluster-based queue process. Unlike the DPP, ERAS will not employ a 3-phase process, cluster studies, use the same withdrawal penalties, or employ many of the other mechanisms associated with the DPP process. Given the unique nature of ERAS, the limited timeframe for which it will be in effect, and the comparatively small number of projects that MISO expects to process through ERAS, MISO submits ERAS as a necessary independent entity variation to MISO's compliance with Order No. 2023-2023-A.

Because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined rule set rather than individual independent entity variations for the numerous differences between the cluster-based process outlined in Order 2023-2023-A and ERAS serial-based study approach. This said, I briefly describe some of the more salient differences below and explain why these are appropriate.

- Serial study: Studying ERAS Interconnection Requests individually in serial fashion will increase the speed of analysis, remove uncertainty caused by other requests being included in those analyses, and allows Interconnection Customers to better replicate study results prior to submission. Cluster studies are more complex with increased uncertainty due to

[3] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008), *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023), order on reh'g, Order No. 2023-A, 186 FERC ¶ 61,199 (2024).

withdrawal concerns since projects are reliant on those in front of them or within their cluster in the review process.

- Different timelines: Individual analysis of ERAS Interconnection Requests allows for a significantly reduced timeline to complete the process and allows for an Expedited Generator Interconnection Agreement ("EGIA") to be executed in months rather than years.
- Higher deposits: ERAS requires higher non-refundable fees and higher milestone payments that must be made at application submission. The financial commitment required for ERAS ensures the level of certainty that the project is ready to move forward and the higher non-refundable fee is necessary to support the additional overhead MISO needs to facilitate the ERAS process.
- Financial commitment to fund Network Upgrades at EGIA: To further validate the certainty of ERAS Interconnection Requests and prevent impact on Interconnection Requests in the DPP that are relying on Network Upgrades identified in the ERAS process, ERAS Interconnection Requests will be required to fund all Network Upgrades once the EGIA is executed, even if that EGIA is later terminated.
- Enhanced Site Control: ERAS Interconnection Requests must present evidence of all necessary Site Control to ensure the project can be built on the generator site as well reach its Point of Interconnection ("POI") on the transmission system.
- RERRA Verification: Interconnection Requests eligible to utilize ERAS must have a written verification from a RERRA, who is ultimately responsible for resource adequacy as noted in the Federal Power Act, that (i) the new, incremental load addition is valid and

is not currently included in a plan or other procedure under the RERRA's purview or (ii) the Generating Facility will address an identified resource adequacy deficiency.

- Off-taker agreement: ERAS Interconnection Requests are required to show that the generation has an agreement with a specific load or is a Load Serving Entity ("LSE") to ensure that generation will be utilized for known load.

Q. IS MISO PROPOSING ANY TRANSITION PROVISIONS FOR THE ERAS FILING?

A. Yes. The transition provisions are included in proposed section 5.13 of the GIP. Generally, the proposed reforms will apply only to ERAS Interconnection Requests submitted after the requested effective date of the reforms, which is August 6, 2025.

III. THE CURRENT MISO QUEUE AND THE ERAS PROCESS

A. ERAS is Necessary to Address Resource Adequacy and Reliability Needs

Q. PLEASE DESCRIBE THE CURRENT STATUS OF MISO'S GENERATOR INTERCONNECTION QUEUE.

A. As of June 5, 2025, MISO's generator interconnection queue contains 1,573 active Interconnection Requests comprising 291 GW of proposed new generator interconnection capacity. This considerable backlog of applications is spread over all five of MISO's study regions and includes queue cycles going back to 2019. The queue size continues to be extraordinary and unprecedented—the 2023 queue cycle, the last to close in 2024, alone is 123 GW. Notably, almost 70% of the total generation capacity that entered the 2017 and 2018 queue cycles was eventually withdrawn. The remaining 30% obtained GIAs, but the actual amount of generating capacity that will be completed and energized will be less than

30% due to financial and construction challenges. Similar withdrawal rates are occurring in the later cycles as well.

Q. DO YOU EXPECT THE CURRENT QUEUE DELAY TRENDS TO CONTINUE?

A. Yes, as I noted in my previous ERAS testimony, I expect the delays to continue in the short-term, as the bulk of the recent proposed generating resources from the unprecedented queue sizes (e.g., the 2022 study cycle included over 956 application submittals totaling approximately 171 GW) continue through the MISO interconnection queue process, and only the 2023 study cycle takes advantage of the queue reforms approved in January 2024 under Docket No. ER24-341-000. Queue delays caused by restudies due to late-stage withdrawals are one of the latest issues negatively impacting Interconnection Customers' ability to timely execute a GIA. Additionally, ongoing delays to resource additions with signed interconnection agreements are caused by supply chain bottlenecks, permitting delays and commercial challenges. To further demonstrate this unprecedented backlog, MISO recently published a COD dashboard to help stakeholders determine when resources might attain commercial operation.[4] These resulting delays are currently interfering with the ability to plan for meeting growing resource adequacy needs and ultimately creates a major reliability concern. The ERAS proposal will help address some of these needs in the short term.

While MISO has taken targeted actions to help manage a highly active generator interconnection queue with process improvements and leveraging technology to speed up processing and studying of new interconnections requests, a temporary solution is required

[4] MISO Generator Interconnection, *COD Report: Overview*, https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

in the short-term to address the immediate and urgent capacity needs until the queue backlog and study timelines are reduced.

Q. IS ERAS A SEPARATE PROCESS FROM MISO'S QUEUE?

A. Yes. ERAS is not a part of MISO's Definitive Planning Phase ("DPP") process. ERAS is also not another interconnection queue that will supplant the generator interconnection process. MISO understands the concerns that ERAS is enabling queue jumping but ERAS is a unique and separate process from the DPP process that is limited in size and scope. The process has extremely stringent eligibility requirements that will limit the projects that can participate in it to those with commercial viability, RERRA verification, and the ability to come online in the next few years. MISO sees ERAS as a complementary process to the generator interconnection queue and a solution that will assist in addressing resource adequacy and reliability needs in the next few years.

Q. PLEASE DESCRIBE WHY ERAS IS NECESSARY.

A. There is a growing critical reliability challenge facing the industry, which has been documented and highlighted in various MISO and non-MISO reports. Examples of such reports include:

1. MISO Futures Report Series 1A: posted in November 2023 and utilized for Long Range Transmission Planning Tranche 2.1 portfolio.[5]
2. MISO's Reliability Imperative Report: 2024 MISO Regional Resource Assessment (RRA).[6]

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[5] *MISO Futures Report, Series 1A* (November 1, 2023), available at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

[6] *2024 Regional Resource Assessment*, A Reliability Imperative Report (January 2025), available at: https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf.

3. The 2024 NERC Long-Term Reliability Assessment (LTRA).[7]
4. The 2024 OMS-MISO Survey: As in previous years, MISO and the Organization of MISO States (OMS) completed a volunteer survey on resource adequacy to identify potential future resource adequacy needs in the MISO region.[8] The 2025 OMS-MISO Survey will be published on the same day as this refined ERAS filing and indicates a similar resource adequacy and/or reliability need trajectory.[9]
5. NERC's 2025 Summer Reliability Assessment.[10]
6. Comments from FERC's Technical Conference on Resource Adequacy.[11]

The reports all include the following elements:

- The increasingly significant challenges facing the MISO footprint in meeting state energy goals and expectations.
  - The RRA report noted that the MISO members and states may need to add capacity at 17 GW/year for 20 years.

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[7] *NERC 2024 Long-Term Reliability Assessment* (December 2024), available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[8] *2024 OMS-MISO Survey Results* (June 20, 2024), available at: https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[9] *See 2025 OMS-MISO Survey Results* (Updated June 2025), available at: https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[10] 2025 Summer Reliability Assessment, North American Electric Reliability Corporation, May 2025, ("NERC 2025 Assessment"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[11] Comments of Todd Ramey on behalf of MISO at 9, Docket No. AD25-7, May 28, 2025 ("MISO RA Tech Conference Comments"); Prefiled Statement of Jim Robb, President and CEO of North American Electric Reliability Corporation at 1, Docket No. AD25-7, May 19, 2025 ("NERC RA Tech Conference Comments").

- The critical timeframe and urgent need for resources on the horizon as demand growth continues to accelerate.
  - The 2024 OMS-MISO Survey found that additional actions would be needed as soon as possible to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements.
  - The 2025 OMS-MISO Survey indicates that "[a]t least 3.1 GW of new resources are needed by summer 2026/27 to avoid a resource deficiency, with greater needs in future years."[12] The survey also states that survey responses show "increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast."[13]
- Indications that MISO is at "high risk" for meeting upcoming resource adequacy requirements.
  - The NERC LTRA report highlights that based on potential delays to generator construction, there is a potential in MISO's footprint to see a 2.7 GW shortfall by 2029 if not earlier.

In further recognition of this issue, the Department of Energy recently introduced the GRID Modernization Initiative, which "envisions a fully integrated electric system from generation to transmission to load consumption … with an emphasis on maintaining the

[12] 2025 OMS-MISO Resource Adequacy Survey Results, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

[13] *2025 OMS-MISO Survey Results* (June 6, 2025) at 10.

reliability and resilience of the grid."[14] Concerns about resource adequacy in the MISO footprint have only increased since the publication of these reports. For instance, MISO initiated the process to redesign the Futures, last finalized in November 2023, as MISO and stakeholders have determined that the load forecasts represented in those Futures are too low. On February 28, 2025, MISO held the first of several workshops to redesign the assumptions within the Futures.[15]

In light of these industry-wide challenges, MISO realized it needed a more responsive process to work with the states to address these resource adequacy needs. The refined ERAS is intended to help maintain resource adequacy integrity within this short timeframe until it sunsets on August 31, 2027, or the completion of sixty-eight ERAS Interconnection Request studies, whichever occurs first. Ultimately, the purpose of ERAS is to provide a mechanism for addressing these resource adequacy and/or reliability needs within this short timeframe, rather than waiting until it is too late.

Q. DOES MISO HAVE ADDITIONAL EVIDENCE TO SUPPORT ITS CLAIM FOR IMMEDIATE RESOURCE ADEQUACY NEEDS?

A. Yes. MISO's internal data supports the general claims about resource adequacy needs. The need for generation to serve load additions through the Expedited Project Review ("EPR") illustrates this challenge and is addressed later in my testimony. MISO has been very vocal about communicating and presenting this impending concern. Simply glossing over this inevitable emerging need for generation only confuses the issue. Additionally,

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[14] *Grid Modernization Initiative*, U.S. Department of Energy (July 2024), available at: https://www.energy.gov/sites/default/files/2024-12/Grid%20Modernization%20Strategy%202024.pdf.

[15] MISO, *Futures Redesign Workshop* (Feb. 28, 2025), available at: https://www.misoenergy.org/events/2025/futures-redesign-workshop---february-28-2025/.

this issue of resource adequacy concerns has been the subject of numerous discussions throughout the MISO stakeholder process for some time now with considerable stakeholder support. MISO submitted comments prior to FERC's Technical Conference on the challenge of resource adequacy in RTO and ISO regions, noting that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[16] MISO also recently published material from its System Planning Committee, which included updates to the Reliability Imperative.[17] The update noted that "[t]here is no single type of investment that will support all system needs; the necessity for near-term but large-scale transmission to support these large load additions recently came to the forefront."[18] The 2025 OMS-MISO Survey will be published on the same day as this filing and its projection are in alignment with the resource adequacy and reliability needs that MISO has referenced in this filing.[19] The survey identifies ERAS as an in-progress initiative and one that will help address resource adequacy challenges.[20]

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[16] *Id.*

[17] *Reliability Imperative: Transmission Evolution*, System Planning Committee of the Board of Directors, Jun. 10, 2025, https://cdn.misoenergy.org/20250610%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution701586.pdf.

[18] *Id.* at 5.

[19] *See 2025 OMS-MISO Survey Results* (June 6, 2025).

[20] *Id.* at 16.

Q. WHY WON'T ERAS PROJECTS BENEFIT FROM THE DPP QUEUE?

A. As detailed in the following testimony and substantiated by multiple examples, a need exists in the near term to accelerate the interconnection process for resource adequacy and/or reliability projects that are unable to benefit from the impact of the recent MISO GIP improvements or Order No. 2023. These resource adequacy concerns are driven by the following: 1) significant growth in spot load; 2) the inability to study new necessary resources immediately upon entering the queue; 3) the accelerated retirement of generation resources; 4) the ongoing delays to resource additions with signed interconnection agreements due to supply chain bottlenecks, permitting delays, and commercial challenges; and 5) the continued large volumes of Generator Interconnection Queue requests and accumulating backlog. The increasing impact of these factors requires urgent improvements to the current GIP to ensure that MISO can meet the challenge. Accepting the proposed ERAS revisions will contribute to ensuring that MISO has sufficient new resources to meet these impending challenges in the coming years.

Q. WHY ISN'T THE CURRENT QUEUE SUFFICIENT TO ADDRESS THESE RESOURCE ADEQUACY NEEDS?

A. MISO successfully implemented several queue reforms improving various aspects of the generator interconnection queue or DPP process. Despite these efficiency updates, MISO's interconnection queue continues to experience significant delays. Due to the aforementioned delays in bringing resources online, the current interconnection queue jeopardizes the short-term availability of resource adequacy projects that are stuck in the queue or are yet to be submitted into the queue. The current DPP queue process will not ensure a timely executed GIA with known Network Upgrades until the backlog is cleared

and a new cycle can be processed with a yearly cadence. MISO is proposing the ERAS process to fill the gap in the short-term by expediting the approval of new generation needed to address resource adequacy and reliability needs.

B. ERAS Projects Will Not Harm DPP Queue Projects

Q. WILL ACTIVE DPP PROJECTS STILL BE ABLE TO TRANSFER TO THE ERAS PROCESS?

A. Yes. If the projects meet the eligibility requirements to enter the ERAS interconnection process, DPP projects in active DPP cycles at or before Decision Point 2 (anticipated only 2022 and 2023 cycles) may transfer to the ERAS process. MISO will not allow Interconnection Requests to transfer from the existing interconnection queue after Decision Point 2 to avoid the Phase 3 restudies due to late withdrawals, which contribute to ongoing queue delays. If an Interconnection Request is beyond Decision Point 2, then it can still drop out of the DPP process; however, it cannot enter ERAS until a year has passed since the withdrawal. This limitation was implemented to maintain the integrity of the DPP process. Allowing active projects in the current queue to transfer to ERAS process also enables the faster completion of studies for projects that can address resource adequacy and/or reliability needs in the short term.

Q. DOES MISO KNOW OF ANY EXISTING PROJECTS IN THE QUEUE THAT PLAN TO TRANSFER TO ERAS?

A. Yes. MISO is aware of several projects that are interested in participating in ERAS and can meet the eligibility requirements. Upon transferring from the DPP process to ERAS, the projects will be subject to all existing withdrawal penalties and/or harm calculations stated in the Tariff. Based on stakeholder feedback, MISO determined that projects

withdrawing from the DPP to enter ERAS should not provide undue impact on Interconnection Requests remaining in the DPP process. That is why withdrawals can only occur at the existing off ramps (i.e. Decision Point 1 and/or Decision Point 2) and that they should be subject to any Automatic Withdrawal Penalty or harm calculation.

Q. WHY ISN'T MISO EVALUATING PROJECTS IN THE DPP QUEUE TO DETERMINE WHETHER THEY CAN ADDRESS RESOURCE ADEQUACY AND/OR RELIABILITY NEEDS?

A. MISO does not believe it is appropriate for it to decide which generation projects address an identified need. MISO is not the resource planner. Ultimately it is the states/RERRAs processes that determine which generation is utilized to meet a resource adequacy and/or reliability need. ERAS provides a means to determine Network Upgrades necessary to aid the states/RERRAs in their determination processes by providing a timely process to study certain Interconnection Requests that the RERRA has acknowledged. Without ERAS, the states/RERRAs need to make their determination after an Interconnection Request is out of the DPP process, which may be too late, or with unknown or incomplete transmission upgrade costs.

Q. WILL ERAS TAKE NECESSARY RESOURCES AWAY FROM THE DPP QUEUE?

A. No. ERAS will not take away resources from the DPP Queue as MISO is requiring significantly increased financial commitments from ERAS participants. First, the D1 payment is $100,000 and is non-refundable. The funds from this payment will provide the additional financial resources needed to help MISO manage the ERAS process. These resources may include additional software tools and enhancements to process ERAS.

Second, MISO has committed to hiring additional personnel or contractors as needed to help manage the ERAS requests. MISO is actively monitoring the workload and need for additional support to effectively process both ERAS and the DPP queue. The cap on 10 projects per ERAS cycle will also make MISO's workload and resource needs easier to forecast and manage. While MISO believes that it has sufficient resources to manage ERAS even without the project cap, MISO recognizes that the project cap will further assist it in efficiently managing both the ERAS and DPP processes. No resources or staff time will be diverted from the DPP queue to ERAS or vice versa.

Q. DO YOU AGREE WITH CLAIMS THAT ERAS WILL REDUCE THE TRANSMISSION CAPACITY HEADROOM AVAILABLE TO PROJECTS IN THE DPP QUEUE?

A. No. As I previously explained in my testimony, ERAS projects will ultimately be studied on a different MTEP base case than projects currently in the MISO queue. An ERAS project that is studied in September 2025 will use the MTEP 2024 base case that is supplemented with changes since that base case was built with both approved EPR projects and new generators with signed GIAs. The 2022 DPP cycle that kicked off in March 2023 used the 2022 base case from when the projects joined the queue. Those DPP projects will have access to the headroom existing in the 2022 base case, which is not impacted at all by the ERAS process.

Q. WILL ERAS PROJECTS SHIFT OR INCREASE UPGRADE COSTS TO CUSTOMERS CURRENTLY IN THE DPP QUEUE?

A. No. This speaks to a misunderstanding of how MISO will create the model for the serially studied ERAS projects. In building the model for new ERAS interconnection projects,

MISO will rely on the latest MTEP base case, including any recently approved EPR projects. In the normal DPP process, the base case is never updated once the study process is kicked off except for changes due to projects withdrawing at the Decision Points or generator retirements, which limits the Network Upgrades to only those introduced as part of the ERAS project.

Q. WHY ARE PHASE 3 PROJECTS NOT INCLUDED IN THE BASE CASE FOR ERAS?

A. MISO does not include Phase 3 projects in the base case for any study process because doing so would require it to deviate from its standard practice. MISO only includes projects that have obtained a GIA in the subsequent base model. MISO does not want to assume that these Phase 3 projects will obtain a GIA, then include them in the model, only to be proven wrong and negatively impact the base model. MISO does not consider projects to be "real" until they have obtained a GIA, at which point they are included in the next base case model.

Q. WHY ARE LATE-STAGE DPP PROJECTS PROHIBITED FROM PARTICIPATING IN ERAS?

A. Late-stage DPP projects are prohibited from participating in ERAS to prevent negative impacts on the DPP queue. To maintain the integrity of the queue, MISO must protect the projects already in the DPP process. Allowing late-stage DPP projects to transfer into ERAS would require their removal from the DPP queue, triggering re-studies. These re-studies would cause delays and adversely affect the remaining projects in the queue.

Q. IN LIGHT OF THE RECENT QUEUE REFORMS, WHY IS IT NECESSARY TO IMPLEMENT ERAS NOW?

A. The recent queue reforms are essential and will result in beneficial changes to the DPP queue, but on a longer time frame than is needed to address current resource adequacy and reliability needs. MISO views the refined ERAS process as complementary to the recent queue reforms but argues that it addresses a more imminent problem. ERAS is not redundant to the existing DPP queue as its purpose and structure is completely different. Several protestors to the original ERAS filing suggested that the SUGAR Software that MISO has been working to implement will solve the problem. However, these claims fail to consider that MISO is currently implementing the SUGAR software only for increasing the speed of the Phase 1 Study of the MISO DPP process, not for the more in-depth Phases 2 and Phase 3, portions. MISO anticipates that it will utilize SUGAR for the later phases, but the software as currently developed is not designed to run the Phase 2 or Phase 3 studies.

Q WHY SHOULDN'T MISO UTILIZE PROVISIONAL GIAs TO ADDRESS THE RESOURCE ADEQUACY AND/OR RELIABILITY NEEDS?

A. A Provisional Generator Interconnection Agreement or PGIA is another tool for Interconnection Customers to achieve a timely interconnection agreement; however, it is insufficient to address the problem on the scale or in the time frame that is needed. Provisional interconnection service, while available for interconnection projects to request as soon as they enter the DPP process, only provides for limited operation, and is conditional on DPP studies for full deliverability that 1) may not be available to recognize the new capacity and 2) can still take several years to finalize. Having a PGIA poses a

substantial risk on generator projects depending on the projects in the queue that may never go commercial or may not be built due to not having an off-taker or a load to serve. Some of the benefits of PGIAs such as increased financial commitments and an expedited timeframe to getting an EGIA were incorporated into the ERAS process. Ultimately, only the ERAS process will ensure that all the Network Upgrades on the MISO transmission system that are necessary to provide deliverability across the system are identified by the time the EGIA is executed.

V. THE REFINED ERAS PROPOSAL

Q. WHY IS MISO REFINING THE ERAS PROCESS?

A. Following the Commission's review of MISO's original ERAS process, it rejected MISO's proposal and made several recommendations for how to ameliorate the issues it identified in the original ERAS proposal. Thanks to this guidance from the Commission, MISO has changed several aspects of its original proposal and is now seeking Commission approval of its refined ERAS process. As explained earlier in my testimony, ERAS is MISO's solution to the near-term resource adequacy and reliability needs within its footprint. Due to unforeseen circumstances related to unexpected and dramatic load growth, MISO needs to implement a process that can enable the completion of projects addressing resource adequacy and/or reliability needs in the next few years. ERAS is not another interconnection queue; rather, it is a separate process that the states may utilize to address short-term resource adequacy and/or reliability needs.

Q. HOW WAS THIS NEW ERAS PROPOSAL DEVELOPED?

A. Following the Commission's Order on MISO's original ERAS filing and other stakeholder feedback, MISO worked quickly to refine its Expedited Resource Addition Study to

address the concerns identified by the Commission and to propose a framework for the accelerated study of generation projects that can address urgent resource adequacy and reliability needs in the near term. With the Commission's guidance, MISO made critical changes to its original ERAS proposal including adding a total project cap with carve outs for retail states and independent power producers. MISO has also added several requirements to establish a stronger connection between the proposed ERAS projects, and the resource adequacy needs that the projects will be addressing.

MISO developed this process and the accompanying Tariff language based on its resolve to address its urgent short-term resource adequacy needs and has provided extensive opportunities for all interested parties to comment during the stakeholder process. It should be noted though that these issues are complex and there is no set of reforms that will flawlessly meet the needs of every stakeholder affected by these updates, but the final ERAS proposal that MISO is submitting today incorporates many of the comments and recommendations we received through this process.

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THIS PROPOSAL.

A. MISO engaged in an extensive stakeholder process throughout the development of the original ERAS proposal. MISO obtained feedback through the Planning Advisory Committee (PAC), conducted dozens of calls with stakeholders across the MISO sectors, and received multiple rounds of both formal and informal written feedback. During the stakeholder process, MISO considered the advantages and disadvantages of multiple approaches for addressing the identified challenges and risks, collaborating with

stakeholders on identifying areas where flexibility could be increased. MISO revised its initial proposal considerably, incorporating the input received.

The key milestones of the original ERAS proposal stakeholder process were as follows:

- November 13, 2024: MISO presented an initial ERAS proposal to the PAC and requested written formal feedback from stakeholders from this meeting be included with feedback from the November 18th workshop.
- November 18, 2024: MISO and stakeholders participated in a special ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the ERAS proposal.
- December 6, 2024: MISO and stakeholders participated in a second ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought written formal feedback on the updated proposal.
- January 22, 2025: MISO presented an updated ERAS proposal at the PAC.
- February 19, 2025: MISO posted proposed tariff redlines, presented an updated ERAS proposal, and sought written formal feedback at the PAC.
- March 7, 2025: MISO posted updated proposed tariff redlines and presented the final ERAS proposal at a special PAC meeting scheduled to review the final details of the ERAS proposal.

The key milestones for the refined ERAS proposal stakeholder process were as follows:

- May 28, 2025: MISO presented its refined ERAS proposal at the PAC.[21] MISO received feedback from this presentation through its informal feedback tool.[22]
- MISO conducted dozens of calls with stakeholders across the MISO sectors.

Q. WHAT WAS MISO'S RESPONSE TO CONCERNS AND RECOMMENDATIONS FROM STAKEHOLDERS ON MISO'S ORIGINAL ERAS PROPOSAL?

A. MISO supported many of the concerns and objectives identified by the stakeholders while crafting the original ERAS proposal and was committed to working with stakeholders to incorporate elements of their proposals to meet those objectives. MISO also considered the concerns and recommendations of stakeholders following the Commission's rejection of its original ERAS proposal. The figure below demonstrates how MISO has worked with stakeholders to address concerns related to ERAS implementation and how its revised proposal responds to these concerns and Commission guidance.

[21] *See Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.

[22] *Informal Feedback (2025)*, MISO, available at: https://www.misoenergy.org/engage/stakeholder-feedback/2025/informal-feedback-2025/.

Figure 1: ERAS Proposal Changes from First Iteration

	Where we began	Original ERAS filing	Refined ERAS filing
Cap	N/A	N/A	No more than 10 projects studied per quarter and no more than 68 projects studied overall with an 8 project carve out for restructured states and a 10 project carve out for IPPs with agreements with entities other than LSEs
Applicants	Load Serving Entities	LSEs, IPPs, and DPP transfer projects meeting all requirements	No change
Process timeline	Project studied and GIA issued in 60 days	Quarterly cadence following established MISO timelines, receiving GIA in ~90 days	No change
Required documentation	RERRA acknowledgement	RERRA acknowledgement and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need	RERRA verification and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need
Identification of need	N/A	Description of need in ERAS application	IC must identify specific load addition and/or RA deficiency the project will address (MW value band, approximate location, etc.) and this information will be made public
Locational requirement	N/A	N/A	Project and RA and/or reliability need must be within the same Local Resource Zone
Size requirement	N/A	N/A	Interconnection Service must not exceed 150% of the identified MW need
Commercial Operation Date	Expected COD with 2-5 years	2025/26 applicants: 3 years from submission plus 3-year grace period; 2027/28 applicants: 12/31/2028 COD plus 3-year grace period	All applicants must have a COD within 3 years of submission plus a 3-year grace period
Penalties	Requested feedback after first PAC	Projects transferring from DPP process will be subject existing tariff language (e.g. AWP and Harm Calculations)	No change
Sunset	2028 / 2029	12/31/2028 or on the completion date of the 2027 DPP queue cycle, whichever first	ERAS will sunset at the earlier of the completion of the sixty-eighth ERAS study or on August 31, 2027

Q. DID MISO CONSIDER ANY ALTERNATIVE ERAS PROPOSALS?

A. Yes. During the stakeholder process in January and February of 2025, two parties submitted alternative ERAS proposals in the PAC meetings. Those proposals focused on improvements to the existing queue process and many suggestions were not relevant to the serial approach of ERAS as MISO has envisioned it. MISO believes the feedback was extremely beneficial but focused on improvements that MISO can make to its current cluster process and not the ERAS process. The refined ERAS proposal does align with a number of items from the Developer Coalition Counterproposal (February 12, 2025),

including limiting the number of ERAS projects allowed to participate and ensuring those projects are tied to a specific need.[23]

The proposals also recommended that MISO utilize a scoring system to evaluate ERAS Interconnection Requests. MISO has not adopted this recommendation because the states have authority over resource adequacy needs and MISO should not be ranking or selecting ERAS Interconnection Requests. It is not appropriate for MISO to be second guessing a RERRA determination that a project should be studied in ERAS.

Q. PLEASE DESCRIBE THE CONCERNS RAISED BY THE COMMISSION'S ORDER AND HOW MISO IS RESPONDING TO THEM.

A. The Commission raised numerous concerns when addressing MISO's original ERAS proposal. The Commission found that MISO's ERAS proposal was not "a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's stated resource adequacy and reliability needs."[24] The Commission identified two main concerns with ERAS: (1) there was "no limit on the number of projects that could be entered into the ERAS process,"[25] and (2) "the proposal does not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[26] The Commission also recognized that it was "appropriate for RERRAs to communicate to

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[23] *See Developer Coalition: ERAS Counter Proposal (February 12, 2025)* https://cdn.misoenergy.org/20250219%20PAC%20Item%2008%20ERAS%20Alternative%20from%20Developer%20Coalition679607.pdf.

[24] *See Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,131 at P 197 (2025) ("ERAS Order").

[25] *Id.* at P 199.

[26] *Id.* at P 201.

MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[27] Each of the Commissioners also filed individual statements urging MISO to revise and refile its ERAS proposal.[28]

MISO is extremely grateful for the Commission's guidance on how to better craft its ERAS proposal and has worked swiftly to develop a refined ERAS process that addressed the Commission's concerns. MISO is now proposing a refined ERAS process that can be implemented by September 2, 2025, to quickly address the looming resource adequacy and reliability needs that it highlighted in its original ERAS filing.

A. Implementing an ERAS Cap

Q. WHY IS MISO IMPLEMENTING A CAP ON ERAS PROJECTS?

A. After receiving feedback from stakeholders and guidance from the Commission in its ERAS order, MISO is implementing a cap on the total number of projects that can participate in ERAS. The Commission was concerned that MISO's original ERAS proposal was unlimited in size and asked that MISO place additional guardrails around ERAS.[29] MISO is now proposing to cap the total number of ERAS projects studied to 68 Interconnection Requests. In addition, MISO is creating a carve out of a maximum of 8 Interconnection Requests (of the total 68) that may be submitted to serve retail choice load and a carve out of a maximum of 10 Interconnection Requests (of the total 68) that may be

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[27] *Id.* at P 203.

[28] ERAS Order at P 3 (Christie, Comm'r, dissenting); P 6 (Rosner, Comm'r, concurring); P 8 (See, Comm'r, concurring).

[29] ERAS Order at P 203.

submitted by IPPs with agreements with entities other than LSEs. The remaining 50 Interconnection Requests may be utilized by the remaining states and developers for non-retail states. MISO recognizes that PJM's Reliability Resource Initiative similarly capped its program at 50 projects and MISO is providing additional carve outs for certain groups that would otherwise have difficulty participating in ERAS. The Commission has previously recognized that an appropriately structured cap used in the interconnection processes can be consistent with open access principles.[30]

Q. IS THERE A LIMIT ON THE NUMBER OF ERAS PROJECTS STUDIED PER CYCLE?

A. Yes. MISO is also going to limit the number of projects studied *per* ERAS quarterly study cycle to 10 projects no matter who submits them. MISO believes that 10 projects per study cycle is a manageable number of projects for its team to study on a quarterly basis. This will allow MISO to spread the number of projects over a longer period of time, which will also help with the expedited review and management of MISO's internal resources to serve ERAS.

Q. HOW WILL THE 10 PROJECTS BE SELECTED FOR THE STUDY?

A. Once the ERAS process is approved, MISO will process the ERAS Interconnection Requests using a serial "first-come, first-served" approach based on the date and time the application was submitted. The first ten projects to submit applications to be studied in ERAS will be tentatively selected until MISO has finalized its screening process of all ten projects to ensure that they (1) meet the ERAS eligibility requirements, and (2) are not

[30] *Id.*

geographically located near another project in the group or impacting the same constraints. After the ten projects in a cycle are finalized, the remaining projects that applied in the cycle will be deferred to the next available ERAS cycle in order of submission time. Since only ten projects will be studied at a time, serial review of the applications will expedite the review process. MISO expects the ERAS Interconnection Requests to apply when they are ready and meet all the necessary eligibility requirements to participate. All application deadlines and ERAS Interconnection Requests will be posted on the MISO public website in a timely fashion.

Q. WHY WILL MISO CREATE A WAITLIST OF ERAS PROJECTS?

A. Projects that apply in a certain cycle but are not the first ten projects that are submitted will be studied in a future ERAS Quarterly Study Period and will remain on an ERAS "waitlist" until MISO has completed a screening process of the first ten projects. After the first ten projects are validated, the remaining projects on the waitlist will be deferred to the next available study quarter in order of when each project was submitted. As soon as the remaining ERAS applicants have gone through the screening process and are accepted into ERAS, MISO will publish the projects and their assigned quarters on the ERAS webpage.

Q. WHAT DOES THE ERAS SCREENING PROCESS INVOLVE?

A. MISO will complete a screening analysis to verify that the projects in a single ERAS study cycle are not in the same geographic area or do not impact the same constraints. If they are in the same area or do impact the same constraints, then the projects will be placed in different quarterly study cycles as separate serial studies. The first submitted project will be processed first, and the next highest priority project (based on submission time) will be processed in a future quarter study cycle.

Q. WHAT IF MULTIPLE ERAS REQUESTS HAVE CONTRACTS TO SERVE THE SAME LOAD?

A. There is a possibility that a very large load will need multiple generators to serve it and would potentially sign agreements with more than one generator. It is incumbent upon the load to determine whether it has negotiated for a sufficient amount of generation and to not rely upon the RERRA to match exact load amounts with generation amounts. It is important to note that these projects cannot be studied together in the ERAS serial process. Thus, the projects would be split over multiple ERAS quarterly study periods in order of submission time even if they are submitted within the same quarter and will serve the same load. MISO recognizes that this is less than ideal from a load need perspective, but in order to ensure that ERAS remains an expedited process that enables the efficient study of ERAS Interconnection Requests in serial order, it must spread out proposed requests that impact the same constraints or serve the same load. This also means that MISO could process a lower queued project ahead of one of these projects if it is a later submitted project that is not similarly situated geographically or if it does not impact any of the same constraints as a higher queued project.

Q. WILL DEFERRED ERAS PROJECTS LOSE THEIR NON-REFUNDABLE D1 PAYMENT?

A. No. MISO will hold their D1, D2, and M2 in order for them to continue to be active requests that are not deficient. But proposed projects that do not meet the ERAS eligibility requirements and are rejected from the ERAS process will lose their D1 payment, but MISO will refund the remaining study and milestone deposits if they withdrawal. Otherwise, they will be automatically transferred into the DPP process. The ERAS projects

will be studied serially in order of submission time. MISO conducts a similar process for the queue cap and will be able to efficiently study the ten projects submitted per ERAS cycle.

B. Updating the RERRA Notification Requirement

Q. WHY DID MISO CHANGE THE RERRA NOTIFICATION REQUIREMENT?

A. Following the guidance provided in the Commission's rejection of MISO's original filing, MISO drafted updated language to better tailor and connect the resource adequacy needs with the ERAS projects as verified by the relevant RERRA. The Commissioners indicated that the previously proposed RERRA notification was insufficient to establish a true connection to the resource adequacy and/or reliability need. MISO is also now requiring that the load being addressed by the ERAS project be in the same LRZ region as the RERRA providing the verification, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the RERRA. An example of a resource filing that was submitted to a RERRA is an Integrated Resource Plan. This is another way to more closely tie the ERAS project to the identified resource adequacy and/or reliability need.

Q. HOW DID THE RERRA NOTIFICATION REQUIREMENT CHANGE?

A. Following the Commission's order, MISO recognized that it needed to change the RERRA requirement and has proposed updated language in the tariff. The Commission noted in its order that "MISO has not demonstrated that the proposed Tariff language is tailored to ensure that only those resources capable of addressing identified near-term resource

adequacy or reliability needs are eligible for expedited study through the ERAS process."[31] Under the new language, the ERAS Interconnection Request must be accompanied by a written verification from a RERRA that either the new, incremental load addition is valid and not otherwise included in a resource plan, or the Generating Facility proposed will address a resource adequacy deficiency as determined by the RERRA.[32] MISO changed the language to better tailor the RERRA notification requirement to a new resource adequacy and/or reliability need. The verification may only come from the RERRA where the load to be served is located and the Generating Facility must be in the same LRZ as the load needed as described above.

Q. WHY IS IT REASONABLE TO REQUIRE A RERRA TO VERIFY TO MISO THAT A PROJECT SHOULD BE CONSIDERED FOR THE ERAS PROCESS?

A. First and foremost, MISO is not a resource planner. It is the reliability and market operator for 15 states and one Canadian province. It is the state or RERRA that has jurisdiction over and determines the resource adequacy needs and/or policies that governs the retail electric service to end-customers. Rather, as noted in the Federal Power Act, the states are the ultimate authority for resource adequacy, hence their necessary inclusion in the ERAS process to address the need for these critical projects to maintain resource adequacy. In order to ensure that the proposed ERAS projects will address a resource adequacy and/or reliability need claimed by an Interconnection Customer, MISO needs the RERRA (or its documented representative) where the load is located to provide a written verification as described above for MISO to study the generation expected to serve that need.

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[31] ERAS Order at P 202.

[32] *See* Tab A Redlines, GIP Section 3.3.1.

This requirement will prohibit the submission of projects that have no connection to a verified load need thereby increasing the certainty that the project will reach completion and prevent speculative projects from using the ERAS process.

Q. WHY IS MISO REQUIRING THE ERAS PROJECT AND THE IDENTIFIED RESOURCE ADEQUACY AND/OR RELIABILITY NEED BE LOCATED IN THE SAME LOCAL RESOURCE ZONE?

A. MISO is requiring the load being addressed by the ERAS project be in the same LRZ as the Generating Facility unless the project applicant can demonstrate that the use of the Generating Facility was included in a resource filing made to the relevant RERRA. Requiring the proposed ERAS project to be located in the same LRZ as the RERRA-verified new, incremental load or resource adequacy deficiency ensures that the generation is going to support the load need in that area. This requirement also ensures that the proposed ERAS project is closely tied to a specific spot load or resource adequacy need. This requirement strengthens the nexus between the new load and the ERAS generation project and will serve as MISO's location criterion, which other RTOs have utilized in their similar proposals.[33]

Q. DOES THE RERRA VERIFICATION CONSTITUTE EVIDENCE OF A DESIGNATION OF NEED OR A FINDING OF APPROPRIATENESS BY THE RERRA?

A. No. The following language was included in the proposed tariff redlines as part of the RERRA verification requirement:

> A RERRA's written verification is not intended to constitute or provide evidence of any final determination of need or suitability of the project for

[33] ERAS Order at P 202.

any purpose by the issuing entity beyond requesting that the Transmission Provider apply the ERAS process for such project.[34]

The purpose of the verification requirement is to confirm to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency. After lengthy conversations with the states during the development of MISO's first ERAS filing, MISO understands that each RERRA has its own process and timeline for formally determining needs and approval processes and that part of these processes by necessity occur after the project has been studied by MISO.

It is important that the RERRA verification not prejudice the ability of the RERRA to make later determinations in accordance with applicable laws and regulations. The purpose of ERAS is to enable the states to meet their resource adequacy needs, while not acting as an impediment to their approval processes. For MISO's purposes, what is important is that it knows which projects to study on an expedited basis and to ensure any Network Upgrades identified in the study, and listed in an EGIA are constructed to provide certainty to later planning processes. The Tariff language meets this need while protecting the rights of the RERRA to make determinations in accordance with its own processes. This language was included to ensure that the RERRA's written verification to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency could not be used by the Interconnection Customer in a subsequent state or RERRA regulatory process as proof or evidence that the project must be approved.

[34] Section 3.9.1.

The RERRAs reserve the right to make a judgement on the need for a project after MISO has studied the project through ERAS as applicable state regulatory processes and approvals still apply. This ensures that MISO's acceptance of the project into ERAS cannot be interpreted as MISO *directing* the state or RERRA to approve the project through their independent regulatory review process. The intention of the language noted above was also to ensure the notification does not pre-determine the outcome of any applicable state process.

In addition, any Network Upgrades identified in the ERAS process and included in an executed EGIA, or filed unexecuted EGIA, will be constructed regardless of whether that EGIA is later terminated due to the ERAS Interconnection Request not being constructed. This adds an additional layer of responsibility to the ERAS Interconnection Request to ensure its certainty and ensures that MISO can utilize that Network Upgrade(s) in later planning processes. For instance, projects within the DPP process can rely on approved MTEP projects, including Network Upgrades approved through the ERAS process, to mitigate constraints identified with the DPP process.[35]

Q. HOW DOES THE ERAS REVIEW PROCESS ALIGN WITH STATE REGULATORY REVIEW PROCESSES?

A. State processes are expected to commence during the ERAS submission window and then work in parallel to ERAS, as presented in Figure 2. These processes may be completed after MISO has finalized the study and issued the EGIA, or potentially complete before the execution of an EGIA. If the state processes and ERAS are done in parallel it may allow

[35] Generator Interconnection Business Practices Manual (BPM-015), Section 6.1.1.1.

for even distribution of work and ensures these critical, time-sensitive projects can proceed efficiently and come online as necessary.

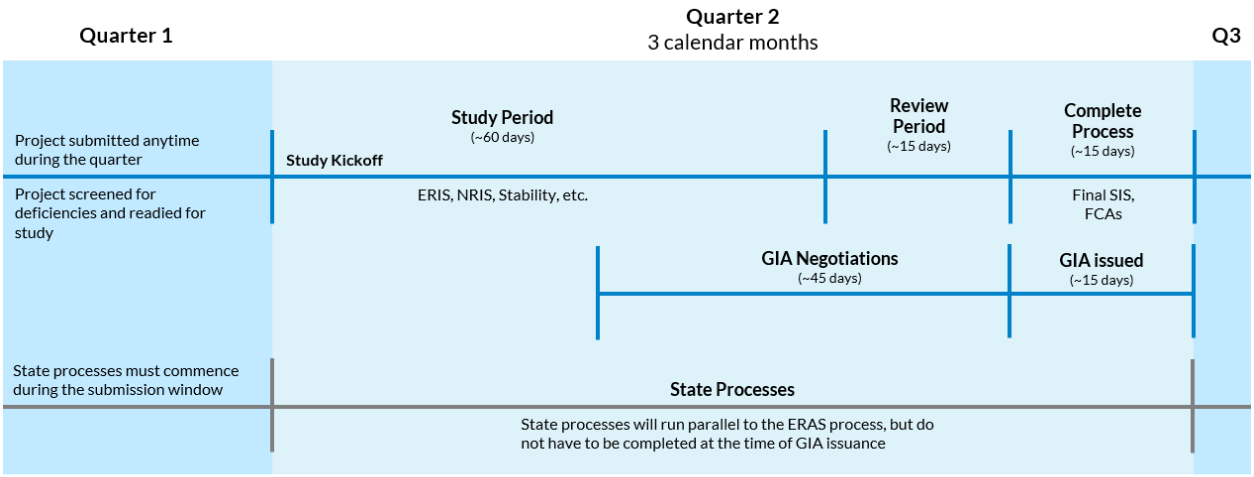


Figure 2: ERAS Quarterly Study Period Example

Q. WILL MORE THAN ONE RERRA NEED TO PROVIDE A VERIFICATION FOR A SINGLE PROJECT?

A. No. MISO is only requiring verification from one RERRA for ERAS participation. The RERRA providing the written verification for the project must be the RERRA responsible for the load that the project is proposed to serve. Per the resource adequacy definition of a RERRA, an identified load can only be regulated by one RERRA.

C. <u>ERAS for Illinois and Part of Michigan</u>

Q. WILL THE REFINED ERAS PROCESS INCLUDE ILLINOIS AND THE RESTRUCTURED PARTS OF MICHIGAN?

A. Yes. MISO has drafted proposed language to incorporate the restructured states into the ERAS process. If an Interconnection Customer's new Generating Facility will address resource adequacy and will either: "(1) serve retail choice load located in a state that limits

the amount of load that can select retail choice to a percentage of the electric utility's average weather-adjusted retail sales; or (2) serve retail choice load and/or be located in a retail choice state other than one that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather adjusted retail sales", the Generating Facility may qualify to participate in ERAS, given it meets all other ERAS requirements.[36] In these instances, the Interconnection Customer will indicate the specific retail choice load on the Interconnection Request and provide evidence of the determination of need, but will not be required to include a verification from a RERRA. MISO is proposing these changes to include Illinois and a small part of Michigan in the ERAS process.

Q. WILL MISO'S PROPOSED LANGUAGE FOR ILLINOIS AND MICHIGAN GIVE PROJECTS AN ADVANTAGE OVER OTHER PROJECTS HOPING TO PARTICIPATE IN ERAS?

A. No. Due to the way that Illinois is structured, it does not have a RERRA that could verify the resource adequacy and/or reliability need like the other states. At first glance, removing the RERRA verification requirement for retail states would seem to give these areas an advantage over other states in the MISO footprint. But MISO has crafted other limitations in the ERAS process that will limit the number of projects that can be proposed from developers in Illinois and Michigan that serve retail choice load. First, only 8 ERAS projects will be accepted to serve retail choice load and only 10 ERAS projects will be studied per cycle. Additionally, those studied within the same quarter cannot be geographically located near other projects or impact the same constraint. Second, the

[36] *See* Tab A Redlines, GIP Section 3.9.1.

ERAS projects will be limited to LRZ regions where the need is located, which will further reduce the number of projects that can be proposed from retail choice states. Interconnection Customers will also still have to provide evidence of determination of need as outlined in the Tariff. MISO is working to level the playing field between the states in its footprint and also wants to ensure that the projects are spread out among the states to better address the resource adequacy and/or reliability needs that they may have.

Q. DO ERAS PROJECTS IN RETAIL CHOICE STATES HAVE A DIFFERENT CAP?

A. Yes. ERAS projects submitted in accordance with Section 3.9.1(1) will be separately limited to a maximum of 8 projects for resource adequacy deficiencies until the sunset of the ERAS process. Retail choice states are a small subset of the MISO footprint and require an ERAS process that is not bound by a RERRA verification due to the need to host an open auction process within those states. Since a RERRA will not be involved in providing a verification for projects proposed in restructured states, MISO needed to ensure that this restructured ERAS process was limited in scope. After an internal analysis and discussion with retail choice states, MISO determined that a cap of eight projects strikes the proper balance between the portion of MISO that the retail choice states represent and the number of projects that will be accepted into the ERAS process. These eight projects will be studied in addition to the 10 accepted by IPPs to serve non-LSE load and the 50 projects allocated for the remaining needs in the MISO footprint, but they will still be limited by the 10 project per quarterly study cycle cap. A member of the IPP sector proposed that MISO set aside a specific number of projects for IPPs to submit with agreements with non-

LSE load and MISO believes that 10 projects is an appropriate balance similar to the retail choice cap above.

D. Changes to the Interconnection Application

Q. HOW HAS THE INTERCONNECTION REQUEST APPLICATION CHANGED FOR ERAS?

A. MISO is requiring additional information from ERAS applicants as compared to other generation Interconnection Requests in order to better tie the ERAS project to the load need and the associated RERRA in the relevant LRZ. As part of the ERAS application process, project applicants will be required to supply a non-confidential summary of the following information: the developer of the ERAS project, the MW range of need the ERAS project is addressing, what LRZ region the project is located in, and a general description of what the load is serving (i.e., a data center, manufacturing plant, a reliability need, etc.). This information will provide MISO will the full picture of the proposed project including fuel source and MW size, details about the load it is serving, and what RERRA is involved in the project's proposal to ERAS. MISO is also planning to publish what cycles the ERAS projects will be studied in and which carve out they are requesting, if applicable. This information will be published on MISO's ERAS webpage as well.

Q. WHY IS MISO IMPLEMENTING THESE CHANGES TO THE APPLICATION FOR ERAS?

A. To further create a tight nexus between the load need and the Generating Facility addressing the need, MISO is requiring additional information be submitted with the ERAS application. MISO is aiming to closely tailor the proposed ERAS project to the verified resource adequacy and/or reliability need and in a more transparent manner. These changes

aim to better connect the ERAS project with the need and the generator addressing that need. With the Interconnection Request application, along with the RERRA verification and the executed agreement, MISO will have a full picture of the ERAS project, the resource adequacy or reliability need it is proposing to address, and all the relevant parties involved with the project. MISO is making the ERAS process more transparent and believes that the additional information required on the Interconnection Request application will serve this purpose.

Q. WHAT DOCUMENTS ARE REQUIRED WITH THE ERAS APPLICATION?

A. Each ERAS applicant will need to submit the following: (1) the Interconnection Request application with detailed information regarding the project, the developer, and the load that will be served; (2) the RERRA verification validating the specific driver (new, incremental load or resource adequacy deficiency) in its footprint; and (3) an executed agreement that the project submitted for ERAS is intended to be used by the entity with an identified resource adequacy or reliability need. As explained above, the ERAS applicants are also required to submit a non-confidential summary of the proposed project that will be published on MISO's webpage.

V. THE ERAS ELIGIBILITY REQUIREMENTS

Q. WHAT ENTITIES CAN SUBMIT PROJECTS TO PARTICIPATE IN ERAS PROCESS?

A. Initially, MISO proposed that only LSEs could apply to participate in ERAS due to their responsibility to serve their load customers. However, based on stakeholder input during the development of the original ERAS proposal, MISO changed course and recognized that the vast majority of the Interconnection Requests, including those that would be submitted

through ERAS, may not be initially submitted by the LSE that ultimately used the resource to serve their load, but rather an Independent Power Producer ("IPP") that would eventually transfer the resource over to an LSE via an offtake agreement. Given the importance of maintaining the inclusivity and open-access aspects of ERAS, MISO updated the eligibility requirements accordingly to ensure that any project developer can apply to participate in ERAS as long as the project meets all of the ERAS eligibility requirements. The refined ERAS proposal has not changed this.

Q. PLEASE DESCRIBE THE ELIGIBILITY REQUIREMENTS FOR INTERCONNECTION SERVICE VIA ERAS.

A. In determining what the necessary eligibility requirements were for ERAS, MISO established requirements that would allow a project to efficiently move through a study process while still being considered "shovel ready." Based on multiple rounds of feedback from stakeholders and additional analysis, MISO is proposing the following technical requirements for ERAS that must be met at the time of application submission:

1. The project must be for new capacity.
2. The project must request Network Resource Interconnection Service (NRIS).
3. Evidence of a written verification from the RERRA where the load to be served is located by the Generating Facility that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency.

4. Evidence substantiating an executed agreement that the project submitted for ERAS is intended to be used by the entity with an identified resource adequacy or reliability need.
5. D1 and M2 payments will ensure increased financial commitment when the ERAS Interconnection Request is submitted. The D1 will be a $100,000 non-refundable fee and the M2 will be $24,000 per MW.
6. 100% Site Control for the generator as well as 100% Interconnection Customer's Interconnection Facilities (ICIF) Site Control will be required when the application is submitted.
7. COD requested in the ERAS application that is no more than 3 years from submission.
8. The project's requested Interconnection Service must not exceed 150% of the identified MW need.
9. The project and the identified resource adequacy and/or reliability need must be in the same Local Resource Zone (LRZ), unless as previously noted.

I provide additional details on each requirement below.

Q. WHY IS MISO REQUIRING AN EXECUTED AGREEMENT TO ADDRESS THE RESOURCE ADEQUACY AND/OR RELIABILITY NEED?

A. Requiring executed documentation by an authorized representative of the entity submitting an ERAS Interconnection Request is reasonable because it allows MISO to balance the appropriate level of "shovel ready" certainty for the critical project. The executed agreement with an off-taker requirement also reduces speculative projects and connects a specific project with a claimed resource adequacy and/or reliability need. Additionally, it

helps verify the accuracy of the information set forth in the ERAS application, which will ensure that MISO will be able to expeditiously transition to studying the project.

Q. WHAT IS THE PURPOSE OF THE BROAD AGREEMENT DOCUMATENTION LANGUAGE IN PROPOSED TARIFF SECTION 3.9.1.2.d?

A. The following language was added to the executed agreement requirement:

> d. Other agreement between the entity submitting the Interconnection Request, including the RERRA verification letter as appropriate, and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier, or its Load Serving Entity), stating that the ERAS project will be used to meet an identified resource adequacy and/or reliability need.

MISO recognizes this language is broad, but the intent of this subsection was to establish a minimum requirement that an arrangement exists between the driver of the need and the project to address that need. As MISO developed this language through the stakeholder process, we determined that requiring a "PPA" or other specified form of agreement, or specific terms, may prove too onerous, especially in jurisdictions where need determinations or commercial commitments are contingent on identified project costs or previous MISO study. What is important is a demonstration that an ERAS Interconnection Request is the solution intended by the entity with the need. The language balances two goals: 1) it prevents speculative requests by entities that are merely hoping to be selected to address a need later, and do not have buy in from the need driver, and 2) it avoids requirements for MISO to evaluate the details of commercial arrangements that may still be in development, which would frustrate use of the ERAS process in many cases. The addition of Alternative Retail Electric Supplier specifically allows agreements with such entities operating in retail choice states.

Q. WHY IS MISO LIMITING ERAS PROJECTS TO 150% OF THE IDENTIFIED MW NEED BASED ON NAMEPLATE CAPACITY?

A. In working to refine the ERAS process, MISO looked at how SPP, CAISO, and PJM structured their corresponding processes. The CAISO proposed a cap of 150% of total available transmission capacity for each of its Deliverable Zones arguing that the "percentage-based nature of the cap ensures that the studies are scaled to the resource and transmission planning completed by the State and local regulatory authorities, while still enabling competition."[37] SPP took a different route – it plans to calculate a maximum amount of capacity that each LRE may propose for inclusion in ERAS and will use a "LRE Ceiling Capacity," which is calculated using "the sum of the LRE's projected capacity, and RAR obligations to obtain the Projected LRE Deficiency and then multiplying that number by the Ceiling Multiplier of 1.25 (i.e., 125%)."[38]

MISO is proposing to limit ERAS projects to 150% of the identified need because MISO's goal is to tighten the nexus between the load need and the proposed ERAS project. Understanding that accredited capacity, depending on the fuel type, is generally lower than 100% for many resources, MISO wanted to establish a closer connection between what is needed and what is being proposed by the ERAS project. The limitation of 150% of identified MW need will strike the proper balance between having a sufficient amount of interconnection service advancing through the study process to support the identified spot

[37] *California Independent System Operator Corporation*, Docket No. ER24-2671-000, CAISO's Transmittal Letter at 6 (filed Aug. 1, 2024).

[38] *Southwest Power Pool*, "Tariff Revisions to Implement the Expedited Resource Adequacy Study" at 29, Docket No. ER25-2296-000 (filed May 22, 2025).

load or resource adequacy deficiency and preventing the overbuilding of resources through ERAS.

Q. HOW IS MISO MEASURING THE 150% OF THE IDENTIFIED MW NEED?

A. MISO is measuring the identified MW need the amount of Interconnection Service requested. Interconnection studies are based on the amount and type of interconnection service requested and they do not assess a generator's potential accreditation. Also, the accreditation of a generator associated with any particular interconnection service may change over time based on the operating characteristics of the generator, the generators attributes, and whether surplus or replacement service is utilized. Additionally, the load an ERAS request will service could have some level of demand response and the ERAS process is fuel agnostic both of which can impact eventual accreditation needs. Based on these different elements, MISO determined that the maximum amount of Interconnection Service that can be associated with an ERAS request would be linked to the amount of load being served rather than on the generator's potential accreditation.

Q. WHY IS MISO STILL REQUIRING HIGHER FINANCIAL COMMITMENTS TO PARTICIPATE IN THE ERAS PROCESS?

A. First, a higher D1 application fee is necessary to implement the temporary ERAS process and cover costs related to processing ERAS Interconnection Requests such as tools improvement, including improvements to MISO's application portal, and/or any additional staffing. This higher and non-refundable application fee will also increase the financial obligations of the applicants, which will ensure that only "shovel ready" projects will be submitted to ERAS.

Second, it is critical that ERAS Interconnection Customers have a greater financial stake upfront for ERAS Interconnection Requests beyond study deposits spent in the study process, as it will encourage a higher level of due diligence and commercial readiness. The increased M2 financial exposure of $24,000 per MW is based on the existing MISO Provisional Interconnection Service's milestones requirements as it represents the same level of upfront commitment for M2, M3, and M4 an Interconnection Customer would make in the DPP three phased process (i.e. $8,000 per MW per phase). Figure 3 presented below demonstrates the differences between the refined ERAS proposal and existing DPP financial requirements. The red font indicates what requirements were added or changed since the original ERAS proposal.

Figure 3: ERAS, DPP, and Common Requirements

ERAS requirements	DPP requirements	Technical requirements

• D1 = non-refundable $100,000
• D2 = $50,000 - $640,000 (dependent on project size)
• M2 = $24,000/MW
• 100% site control (site and POI)
• Service type: NRIS
• RERRA Verification
• Executed agreement/PPA/BTA
• COD no later than 3 years from 2025/2026 submission
• No more than 68 total ERAS projects
  ◦ 8 project carve out for restructured states
  ◦ 10 project carve out for IPPs with agreement with entities other than LSEs
• No more than 10 projects studied per quarter
• Interconnection Service must not exceed 150% of the identified MW need
• Project and RA/reliability need must be within the same Local Resource Zone
• IC must identify specific load addition and/or RA deficiency the project will address (MW value, location, etc.) – this information will be made public
	• D1 = $7,000
	• M2 = $8,000/MW
	• M3 = 20% of NU – M2
	• M4 = 30% of NU – M2 and M3
	• 50% POI site control or $80,000/line mile with 100% generating facility site control
	• Service type: ERIS or NRIS
	• COD no more than 5 years from submission, plus 3 years during negotiation, plus 3-year grace period
		• Synchronization Date
		• Commercial Operation Date
		• Interconnection Facilities In-Service Date
		• Service Type (NRIS)
		• Generator Output
		• Primary Fuel Type
		• Generator Manufacturer & Model Number
		• Library Stability Model
		• One-Line Diagram
		• Generating Facility Data
		• Step-Up Transformer Data

Q. WOULD ERIS REQUESTING NRIS QUALIFY UNDER ERAS?

A. No. One of the eligibility requirements for ERAS is that it must represent new incremental capacity. In the instance of an interconnection request with ERIS working to add NRIS to

their request, this would not represent new capacity but rather an uprate to existing interconnection service. This type of request does qualify for an exemption to the queue cap though and can proceed through the next DPP cycle automatically.

Q. CAN EXTERNAL GENERATING RESOURCES REQUESTING NEW INCREMENTAL NEW CAPACITY REQUEST ERAS?

A. Yes. An ERAS request associated with an external generating resource, requesting External NRIS, would be studied under the standing NRIS study procedures covered under the proposed section 3.9.3 of Attachment X. This proposed project must still meet all the other ERAS eligibility requirements including providing a RERRA verification.

Q. WHY IS MISO STILL REQUIRING 100% SITE CONTROL FOR ERAS PROJECTS?

A. The increased gating requirements involving Site Control and financial milestones for ERAS Interconnection Requests are reasonable because they reflect the importance of preserving the integrity and certainty of these projects. It also helps to ensure that MISO will not get inundated with projects that are not shovel ready even with the new ERAS cap. Requiring 100% Site Control to the POI with the ERAS application submittal, along with the existing requirement of 100% Site Control for the Generating Facility encourages only shovel ready project applicants apply to ERAS. ERAS Interconnection Requests must address a resource adequacy and/or reliability need in the short-term, which essentially requires the project to be shovel ready in the next few years. The 100% Site Control requirement is also designed to discourage speculative and non-ready projects from

entering ERAS. To that end, MISO also determined that there would be no Financial Security option for the POI Site Control like is available within the DPP process.

Q. WHY DOES AN ERAS INTERCONNECTION REQUEST NEED TO HAVE AN ACCELERATED COMMERCIAL OPERATIONS DATE ("COD")?

A. Under the current DPP timeline requirements, to use an example, an Interconnection Request submitted in the 2025 DPP study cycle would not need to come online before 2036. First the applicant into the DPP process can have a COD that is no more than 5 years out. Second, during GIA negotiations the Tariff allows the IC to extend the application COD by an additional 3 years. And finally, the *pro forma* GIA allows for a 3 year grace period beyond the COD documented in the GIA for a total of 11 years after initial submission.

Given the urgent resource adequacy needs identified earlier, another tool or mechanism is needed to ensure that the ERAS Interconnection Requests come online as soon as possible. MISO is requiring that ERAS projects have a COD within 3 years of their ERAS submission date unless the project is deferred to a later quarter at which point the COD can be adjusted during GIA negotiations to be no more than 3 years from the kickoff of that project's ERAS quarterly study cycle. Interconnection Service granted through ERAS would continue to have an additional grace period of 3 years from the COD date in the EGIA to become commercial as noted in MISO Appendix 6 Generator Interconnection Agreement (i.e. the *pro forma* GIA). This COD requirement in addition to other eligibility requirements, including increased financial commitments and obtaining 100% Site Control, will ensure that only projects that can achieve commercial operations quickly participate in ERAS.

Q. HAVE STAKEHOLDERS OR OTHER INTERESTED PARTIES EXPRESSED CONCERNS REGARDING THE COD REQUIREMENT?

A. Yes. ERAS has ultimately been crafted in a transparent and collaborative manner to achieve a near term resource adequacy goal to maintain reliable grid operations. MISO worked to balance the end date to enable projects at differing points in the preparation process to participate in ERAS – some projects will be ready to participate this year, while others are working to have their projects ready to participate in 2026 or later. MISO will allow an extension on an ERAS project's COD deadline if it is deferred to a later study quarter.

Q. HAS MISO CONSIDERED THAT ERAS INTERCONNECTION REQUESTS WILL BE SUBJECT TO THE POTENTIAL DELAYS (SUPPLY CHAIN, REGULATORY, SITE CONTROL, ETC.) THAT DPP PROJECTS ARE SUBJECT TO?

A. Yes. MISO has taken these concerns into consideration. During the original ERAS discussions, we continued to hear from our Interconnection Customers that these issues persist. For this reason, MISO is proposing that Interconnection Service granted through ERAS would utilize the same grace period of 3 years from the COD date in the ERAS application to become commercial that all other Interconnection Customers have as noted in the MISO *pro forma* GIA. MISO recognizes there are numerous industry challenges outside of developers control and wanted to provide a sufficient amount of time for the developers to get their projects ready within this context. The current timeframe proposed

for ERAS should be sufficient to provide developers with time to overcome any supply chain or other unknown delays.

It should also be noted that as previously mentioned, given the increased gating requirements (Site Control, increased financial commitment), this ultimately helps to ensure that MISO will not get inundated with projects that are not shovel ready.

Q. HOW WILL MISO CLOSE OUT THE ERAS PROCESS?

A. The ERAS process will sunset at the earlier of the completion of sixty-eight ERAS Interconnection Request studies or by August 31, 2027. This time limitation also applies to the projects proposed by the retail choice states – if the eight projects are not submitted by the sunset date, the ERAS process will still close on August 31, 2027. The same is true for the projects proposed under the carve out for IPPs with agreements with entities other than LSEs – if the ten projects are not submitted by the sunset date, the ERAS process will still close as planned. MISO will only accept applications to be included in the last Quarterly Study Period prior to the sunset date. MISO will post the application deadline for each Quarterly Study Period on the MISO public website.

VI. ERAS PROCESS COORDINATION

A. Coordinated Study Processes

Q. PLEASE DESCRIBE THE EXPEDITED PROCESSING OF THE EGIA.

A. The refined ERAS process will still enable all parties to move expeditiously through EGIA negotiations. Because of the critical reliability need for ERAS Interconnection Requests and to ensure an overall expedited process for commercial operations, the EGIA follows an expedited timeline. The drafting of the EGIA by the MISO team will begin as soon as possible. Additionally, under the EGIA timing requirements for ERAS, MISO will tender

a draft EGIA within five (5) Business Days after the Interconnection Customer provides notice to proceed to EGIA negotiations. Following this, an EGIA would be tendered in less than 30 business days.

Q. HOW WILL MISO PROVIDE INTERCONNECTION CUSTOMERS SUFFICIENT TIME TO EXECUTE A GIA?

A. In crafting the ERAS process, MISO recognized the need to implement a shorter timeframe for the EGIA negotiation process to ensure that the overall ERAS process could be completed within 90 days. To that end, MISO will begin drafting an EGIA document as soon as possible. This ultimately enables the EGIA negotiation process to work in parallel with the study process and therefore the EGIA draft will be substantially further along at the end of the ERAS study process. As a result, after the Interconnection Customer issues their notice to proceed, an EGIA can be tendered for the execution in less than 30 business days.

Q. CAN INTERCONNECTION CUSTOMERS WITHDRAW FROM ERAS?

A. While there is a critical need for these ERAS Interconnection Requests, the proposed requirements still allow the Interconnection Customers an opportunity to withdraw once they are aware of the Network Upgrade costs. Moreover, it is possible that an Interconnection Customer may discover various issues with the proposed site in the ERAS process that would influence their desire to withdraw, or the RERRA could ultimately deny the project through their own processes. If the Interconnection Customer withdraws and terminates its EGIA after execution by all parties or after the EGIA is filed unexecuted, the Interconnection Customer will remain liable for the Network Upgrades documented in the EGIA and corresponding Facilities Construction Agreements ("FCAs") or Multi-Party

Facilities Construction Agreements ("MPFCAs"), including those Network Upgrades arising from the Affected System Study process. If the ERAS Interconnection Request is withdrawn prior to EGIA execution, then there is no agreement to fund Network Upgrades and no impact on downstream planning processes. In these cases, the Interconnection Customer would be refunded their M2 payment and any remaining D2 payments not utilized to perform the study.

The increased penalties for Interconnection Customer withdrawals after the execution of the EGIA, along with the other requirements like the off-taker agreement and the RERRA notification, will help ensure that only critical projects needed for maintaining reliability and/or resource adequacy will apply to ERAS. Under the current effective GIP and DPP process, when an Interconnection Request is potentially withdrawn from the queue, there would be minimal financial exposure to the Network Upgrades. Given the urgent need for ERAS projects, MISO is requiring increased penalties to discourage Interconnection Customers from withdrawing from the ERAS process. More stringent requirements have the added benefit of reducing the potential speculation of the ERAS Interconnection Requests. Fewer speculative projects entering the ERAS process will result in shorter timelines for completing the ERAS Interconnection Studies. This requirement will also motivate developers to run their own studies beforehand.

Q. PLEASE DESCRIBE HOW INTERCONNECTION SERVICE GRANTED THROUGH ERAS WILL BE STUDIED AND HOW IT WILL COORDINATE WITH THE CURRENT DPP PROCESS.

A. The ERAS process will kick off starting September 2, 2025, and will integrate with existing processes without disrupting the ongoing DPP process. As explained previously in my

testimony, Interconnection Requests submitted through ERAS will be studied in a regional serial "first-come, first served" fashion based on the order the projects were submitted. It will follow a quarterly cadence established by proposed MISO timelines, ultimately culminating in the project receiving an EGIA in approximately 90 days. MISO proposes to utilize the existing engineering study process utilized in the DPP for ensuring full generator deliverability to the load. During the ERAS model build, all Existing Generating Facilities, included those from completed DPP cycles, the ERAS Interconnection Request, and the latest MTEP base case with all approved MTEP projects, including any recently approved Expedited Project Request ("EPR") projects. This is the same process utilized for the DPP process except the DPP models include all higher queued Interconnection Requests from early cycle and all Interconnection Requests within that DPP cycle. ERAS studies will not include Interconnection Requests currently in the generator interconnection queue that do not have a GIA. This is important as many of the projects within the queue are speculative in nature given that more than 70% of the Interconnection Requests submitted into the DPP withdrawal or never get built.

Before every ERAS cycle, all Interconnection Requests with a GIA approved since the last base case was created will be added to the base case for the following ERAS cycle but are not included in any ongoing DPP studies. The base case for each DPP cycle is never updated once the study process is kicked off except for generation changes due to Interconnection Request withdraws or generator retirements. This ensures that the transmission capacity made available for DPP projects is not being taken away by ERAS Interconnection Requests approved outside of the DPP cycle.

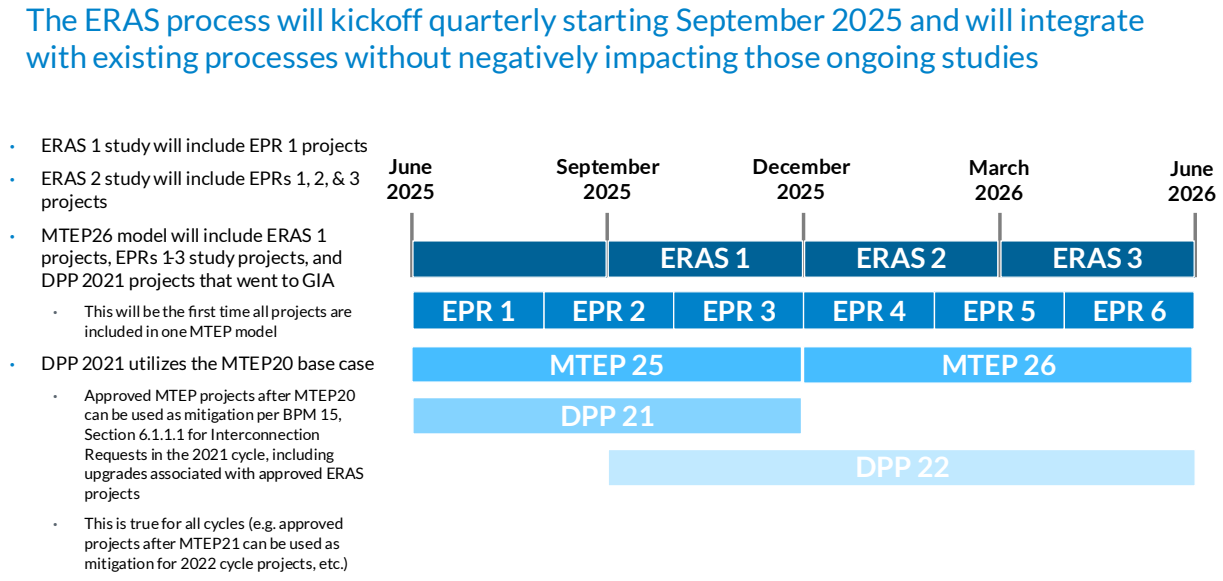
Once the DPP cycle has concluded, the output from that process, and any completed ERAS and EPR projects will be used to populate a new MTEP base case. Any transmission issues identified by reconciling the cases will thus be addressed through the existing MTEP process. The next DPP cycle will then use the latest approved MTEP base case that has reconciled the models. This insulates existing DPP projects from negatives impacts or cost shifts due to the existence of the ERAS process. The contingent facilities listed in the EGIA would only be those facilities in the model used for the ERAS study and those Network Upgrades that come up as part of the ERAS study.

Q. WILL ERAS PROJECTS NEGATIVELY IMPACT EXISTING PROJECTS IN THE GENERATOR INTERCONNECTION QUEUE?

A. No. Under this model framework, the standing MISO DPP three phase process will not be impacted by ERAS as ERAS Interconnection Requests will not be included in ongoing DPP studies thereby not utilizing any available transmission capacity in those studies. The normal DPP process uses the most up to date MTEP base case when the study is kicked off and is not modified to include later approved MTEP projects or ERAS Interconnection Requests. Although these projects approved after the kickoff the DPP process are not included in the study, there is an existing process that allows these projects to mitigate constraints within the DPP process with MTEP projects. Network Upgrades approved through the ERAS process will also be used to mitigate constraints in the DPP process. ERAS will only positively impact the Network Upgrade identification process of these other processes.[39] This coordinated process is demonstrated in Figure 4 below.

[39] This is further addressed in section 6.1.1.1 of the BPM-015 Generator Interconnection Business Practice Manual.

Figure 4: MISO Coordinated Study Processes



Q. WHAT WILL HAPPEN IF TRANSMISSION CAPACITY IS OVERALLOCATED DUE TO AN APPROVED INTERCONNECTION REQUEST IN ERAS AND THE DPP?

A. On the rare occasion that overallocation may occur, it would be discovered as part of the standing MTEP Deliverability Analysis. The process has been structured so that there cannot be any negative impact to the projects currently in the DPP process, but this can lead to a potential occasion of overallocation. There will be no negative implications for either the DPP Interconnection Request or the ERAS Interconnection Request due to this rare occurrence. Both will be allowed to proceed, and neither will be required to pay additional costs due to the overallocation. MISO performs generator deliverability analysis as a part of the current MTEP process to ensure continued deliverability of generating units with Network Resource Interconnection Service. Results of the assessment are based on an analysis of near-term (5-year) and long-term (10-year) summer peak scenarios. Any

constraints that are identified as needing mitigation would be formalized in a future MTEP project.

Q. WHO IS ASSIGNED THE COST OF THE MTEP PROJECT APPROVED TO MITIGATE ANY OVERALLOCATION SCENARIO?

A. The cost of the MTEP project will be allocated based on the existing Tariff rules, which is likely to be the load within the transmission pricing zone where the transmission upgrade is located. However, it is also expected that this load will include the load that is benefiting from the ERAS and DPP Interconnection Requests and benefits from the Network Upgrades that were funded by the generators that went through those processes. In addition, the cost shift is consistent with existing processes. In particular, MTEP projects that are approved after the start of a DPP cycle or even MTEP projects that are approved after the execution of a GIA, can be utilized to mitigate constraints identified in the DPP process. Therefore, an Interconnection Request can be contingent on that MTEP project instead of relying on the original Network Upgrade identified through the DPP process to mitigate that DPP constraint. As a result, the elimination of that Network Upgrade, the Interconnection Customer will not have to pay those costs. This is a cost shift where the load will pay for the MTEP project instead of the Interconnection Request paying for the Network Upgrade.

Q. ARE THERE OTHER INSTANCES WHERE PREVIOUS PARALLEL STUDIES CAN RESULT IN NEW CONSTRAINTS THAT ARE IDENTIFIED LATER IN A FUTURE MTEP PROCESS?

A. Yes. MISO has multiple planning processes, many performed in parallel. These processes have their own unique modeling assumptions that are vetted through the stakeholder

process. These processes also have different cost allocation methodologies based on "but for" and "beneficiary pay" principles that are vetted through the stakeholder process. Some examples are Baseline Reliability Projects, identified to meet standards for both NERC and regional reliability; Market Efficiency Projects, which address economic driven congestion; Multi-Value Projects, identified through the Long Range Transmission Planning process; Transmission Deliverability Service Projects, identified to support transmission service; Interregional Transmission Projects, identified to improve reliability and/or economic driven congestion within MISO and a neighboring RTO; Other Projects, identified to support local reliability issues like those identified to add load in the EPR process; Generator Interconnection Projects, which are Network Upgrades identified to reliably connect new Interconnection Requests; and new Generating Facilities that are approved through the DPP, surplus or replacement processes.

After all these projects are approved through their relevant processes, they are then included in the base cases of subsequent studies based on the modeling assumptions for those studies. It is not uncommon for new constraints to arise in subsequent studies driven by all of the approved transmission and generation projects, as well as due to new load growth, and the retirement of generation. Constraints could also be negatively impacted by similar processes in neighboring Transmission Providers. As these new constraints are identified new mitigation is identified, which could include another new transmission project necessary to ensure reliability.

B. ERAS and the EPR Process

Q. WHY IS THERE AN EPR GENERATION SHORTAGE?

A. Expedited Project Reviews ("EPRs") are requests by a Transmission Owner for MISO to quickly review the impacts of a proposed transmission project on the MISO Transmission System. A Transmission Owner requests these reviews when it determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project.[40] By default, MISO reviews such projects for inclusion in MTEP within a thirty-day timeframe. EPR requests generally reflect an emergent need on the Transmission System that must be evaluated more quickly than the normal MTEP planning process and timeline allow. The announcement of a large and concentrated load addition at a given point on the Transmission System, such as a data center, is a common driver for EPRs. The EPR process reflects the fact that this load must be served and that doing so may require rapid enhancements to the transmission system. Recently, MISO has had to rely on increased transfers to serve these large loads due to the lack of local generation to serve the load, thereby increasing the amount of transmission upgrades necessary to support the load additions. Additionally, Transmission Owners have been unable to support the full amount

[40] EPRs are governed by Appendix B, Section VII of the Transmission Owners' Agreement, Section I.D.1.c of Attachment FF to the Tariff and Section 4.1.4 of Business Planning Manual 20 (Transmission Planning).

of load a customer would want to connect at a particular location due to the inability to quickly add local generation to support the load.

Q. HOW ARE EPRs CONNECTED TO ERAS?

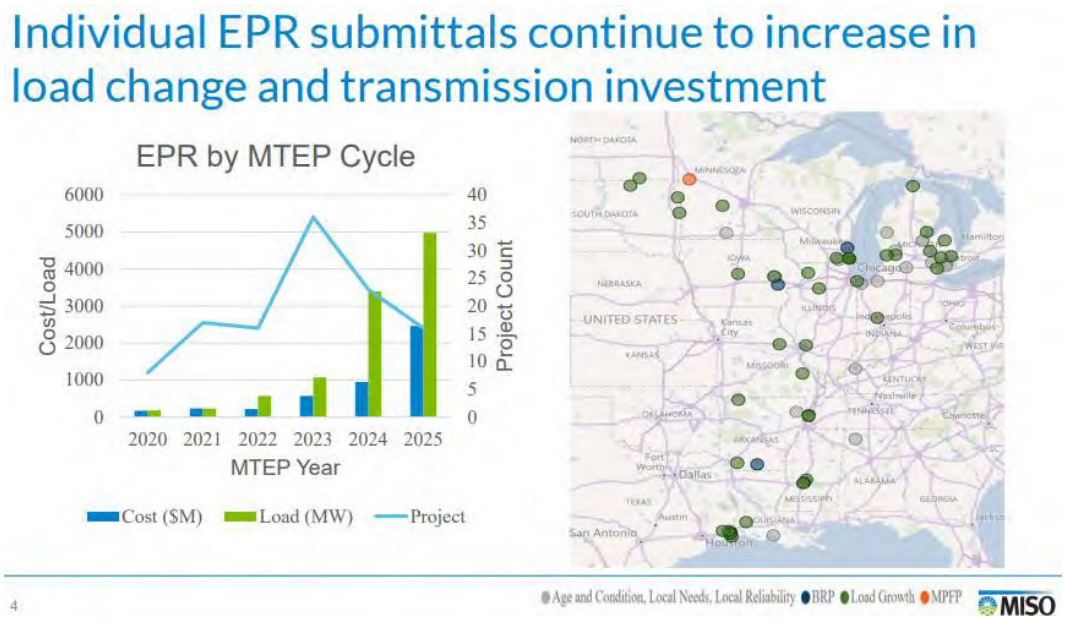
A. While EPRs address the transmission development demands associated with large load additions, these additions may also require a corresponding need to evaluate generation on an expedited basis to serve this load. The EPR process models generation that has a signed GIA, but there is no guarantee that new generation will be interconnected to the Transmission System at a point that can reliably and cost effectively serve the emergent load need. In fact, given the length of MISO's DPP queue delays and the typical generation development timeframe, it is unlikely such load demand was known at the time that any generation projects with a GIA were originally submitted into the queue. Thus, it is unlikely that a generating unit with a high degree of certainty of being online by the needed date of that load driver also happened to be situated in a place where it could reliability serve the emergent load need without significantly extending the length (and cost) of the EPR in order to connect at a point on the Transmission System where excess generation is available. This is especially true given the fact that the EPR can be the first and only connection from that load source to the Transmission System. The EPR process is about approving the transmission necessary to support new load growth, but not the load itself. The EPR process allows for a faster study method to allow these loads to connect sooner than going through the traditional MTEP process. A similar expedited process is needed to study new generation that is necessary to serve spot loads added through EPR. ERAS

supplies this previously missing and much needed connection that complements the EPR process.

Q. HOW OFTEN DOES MISO RECEIVE EPRs?

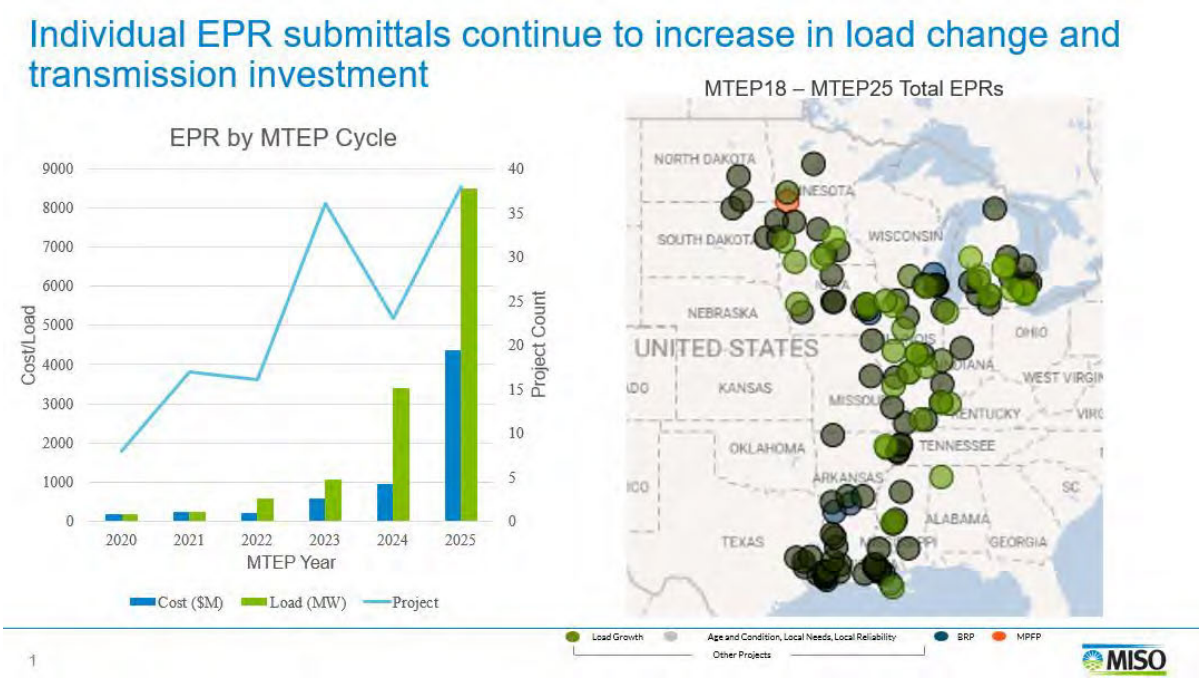
A. In the past, EPRs were comparatively uncommon. However, MISO's most recent data shows a sharp increase in the number of EPRs being submitted in the last few years. As an example, simply comparing the difference from the January PAC Meeting EPR presentation to the current version as of April PAC Meeting EPR presentation, which takes into account the new EPR projects that have recently been submitted, the following figures demonstrate the huge increase and the need for generation to cover this immediate spot load growth.

Figure 5: January 2025 PAC EPR Presentation[41]



[41] MISO EPR Process Improvement Update, PAC-2024-1, Planning Subcommittee, Jan. 29, 2025, available at: https://cdn.misoenergy.org/20250129%20PSC%20Item%2004%20EPR%20Process%20Improvement%20(PAC-2024-1)674593.pdf.

Figure 6: April 2025 PAC EPR Presentation[42]



The data in these figures demonstrates two important trends. First, there has been a substantial increase in the number of EPRs being submitted to MISO. In MTEP 20 and MTEP 21, MISO received only 8 and 17 EPRs respectively. However, MISO has already received more than 38 such requests for MTEP 25. Second, this increase in EPRs is linked to a significant increase in the associated Network Upgrade costs needed to accommodate the EPRs – jumping from an average of $13.7 million in 2022 to $175 million so far in 2025 as shown in the graphics above. This is in part because there is insufficient local generation to serve this load.[43] Absent an accelerated process like ERAS, it is unlikely that

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[42] *MISO Sharing and Coordinating MTEP and DPP to Accommodate Large Loads*, PAC 2024-7, Planning Subcommittee, Apr. 23, 2025, available at: https://cdn.misoenergy.org/20250423%20PSC%20Item%2005%20Sharing%20and%20Coordinating%20MTEP%20and%20DPP%20to%20Accommodate%20Large%20Loads%20(PAC-2024-7)692381.pdf.

[43] A further compilation of some of these projects was recently presented at the April PAC meeting. *Expedited Project Reviews*, Planning Advisory Committee (PAC), Apr. 16, 2025, available at: https://cdn.misoenergy.org/20250416%20PAC%20Item%2004a%20Expedited%20Projects%20Reviews690477.pdf.

the generation needed to support spot load will be located in close proximity to the load being added, thus increasing the need for and cost of additional transmission to bring in generation from remote areas.

Q. WHY IS LOCAL GENERATION PREFERABLE WHEN ADDING LARGE SPOT LOADS?

A. Local generation is preferable when adding large spot loads for multiple reasons. First, local generation will reduce the need for large transmission upgrades to support the new load and generation. Instead of making transmission investments around the remote generation to support the generation exports or making transmission investments to support importing power to serve the load, the load and generation rely on each other and negate the needed transmission investment. Second, there is a limited amount of import capabilities between Local Resource Zones. Relying on generation within the same zone will remove the need to import power from another zone, which benefits and helps all load within the zone. Third, relying on generation within the same zone removes price divergences between the load and generation. The EPR process uses whatever generation it can to support that load addition. ERAS will help reduce network upgrade costs by providing a process to quickly add local generation that the EPR process can rely on. The new LRZ requirement in the refined ERAS process will also ensure that the new generation is local to the resource adequacy and/or reliability need.

Q. WHY IS ERAS NEEDED TO ADDRESS THE EPR GENERATION SHORTAGE?

A. Some protestors in the original MISO ERAS filing argued that MISO should not attempt to meet the load need by its anticipated need-by date. Instead, they argue that MISO should wait and utilize the existing 53 GWs or more of generation with signed GIAs that are

currently delayed in coming online in the time period needed to address the imminent resource adequacy and/or reliability needs.[44] I have evaluated this approach and have concluded it is impractical and unreasonable for several reasons.

First, the EPR process already includes in its models any generation units with signed GIAs that may or may not come online in time. Thus, even with MISO taking into account these GIAs, there is still a local generation deficiency to meet the load need. Second, it is not reasonable to assume in all cases that generation coming online will meet the specific needs of emerging spot load. For example, while a superficial glance at the number of units with signed GIAs may suggest that there is a sufficient number of MW somewhere on the MISO system, these specific units may not always be sufficient to meet the load need. For instance, if a data center with a 2 GW load need plans to run continuously (or mostly at night), the fact that there are 2 GW of uncommitted solar with a near term Commercial Operation Date is likely insufficient to reliably meet this need. Third, these generation units with signed GIAs may not be geographically situated in proximity to the spot load and, due to the nature of their agreements, are precluded from modifying their designated Points of Interconnection. Finally, there is no guarantee that these units with a near-term Commercial Operation Date will actually come online by that necessary start date. I have observed a significant increase in the number of units with GIAs that are not in service by their Commercial Operation Date and are using or expect to use much of the three-year grace period allowed by the *pro forma* GIA.[45] In addition, an increasing number of these

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[44] A dashboard of this 50 GW in generation is available in MISO Generator Interconnection COD Report: Overview, last updated June 5, 2025.

[45] *MISO Generator Interconnection COD Report: Overview*, last updated June 5, 2025, available at: https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5OD

units are requesting extensions of their Commercial Operation Date through waivers. These facts lead me to conclude that there is an urgent need for a specialized interconnection process that can deliver highly certain generation that is tailored towards the specific load need and already has some level of commercial arrangement to serve it, on an accelerated basis. Absent the ERAS tool, I expect to see: (1) a continued escalating number of EPR submissions relying on remote generation; (2) increasing Network Upgrade costs associated with EPRs; (3) and instances where load that cannot be served as of the date it plans to come online.

Q. WHAT CAN BE DONE TO IMPROVE THIS IMPENDING SITUATION?

A. It is necessary for MISO to establish a new process from the existing that can enable Interconnection Customers to work with RERRAs to identify load needs and work with LSEs or other developers to address them. After working together to develop the best project to address a resource adequacy and/or reliability need, the Interconnection Customers can propose highly certain projects to participate in ERAS and ideally be brought online on an expedited basis to meet the load need. A new process is needed that will enable potential Interconnection Customers to confer with RERRAs and load drivers about urgent reliability or resource adequacy needs; scope and present their proposed projects to the RERRA and need/driver or LSE; and then come to MISO with highly certain projects that can be studied and brought online on an expeditated basis to meet the load need. While MISO expects that the vast majority of Interconnection Customers and resource adequacy needs will not require such a process, as they will continue to rely on

k0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

the DPP queue, MISO still requires a temporary and specialized process to rapidly study those few projects that are slated to address those critical and urgent needs. MISO cannot force generation to come online, or cherry pick which generation projects should be expedited over others. But what it can do is create a pathway for generation that is shovel ready, slated to meet specific needs that the applicable RERRA has validated, and for which MISO should study on an accelerated basis. This process should have the guardrails proposed in this refined ERAS filing to ensure that the process is available to those critically needed projects with commercial certainty without otherwise becoming a substitute for the DPP.

C. ERAS and the Affected System Studies Process

Q. WHAT IS THE PROCESS FOR CONDUCTING ERAS AFFECTED SYSTEM STUDIES?

A. The refined ERAS proposal was designed with the expectation that MISO would utilize existing affected system studies processes. MISO is actively working with multiple seams partners to develop additional seams procedures to incorporate the ERAS process. MISO is committed to and planning to be able to deliver those on an expedited basis consistent with ERAS even before specific processes are addressed and would follow the existing tariff language and does not prevent MISO from doing this faster.

Q. IS MISO CONTINUING TO IMPROVE QUEUE COORDINATION WITH INTERCONNECTION CUSTOMERS AND TRANSMISSION OWNERS?

A. Yes. MISO always seeks proactive continuous improvement of its interconnection queue. In addition to these proposed Tariff changes, MISO has multiple efforts underway to enhance the queue experience. Examples of ongoing or completed initiatives include the

queue reforms approved in January 2024 to increase readiness, the queue cap approved in January 2025, implementation of SUGAR software to automate and increase the speed of the Phase I study, further improvements to the generator interconnection portal which automates some manual processes in the interconnection application process, and the Commercial Operation Date tracker, which debuted in early 2025 and provides greater transparency into the status of future Generating Facilities in MISO.[46] These initiatives will strengthen Interconnection Customer workflow throughout the Interconnection Request lifecycle. MISO is coordinating the development of these enhancements through the stakeholder process and outside vendors. MISO is also working to identify additional processes and tool improvements to improve the overall DPP process.

Q. WILL ERAS INTERCONNECTION REQUESTS GO THROUGH THE AFFECTED SYSTEM EVALUATION PROCESS?

A. Yes. MISO must coordinate the impact of these projects with its existing Affected Systems partners to ensure they do not cause reliability impacts on non-MISO transmission systems. The Affected System Studies analysis is an important part of the standing interconnection process and must be performed as part of this evaluation. Subsequently, where available, MISO will incorporate the results of the associated Affected System Studies analysis in the EGIA. For those instances where the results from the Affected System Study analysis are not available to incorporate, given the accelerated timeframe for ERAS, the results will be provided at a later date.

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[46] MISO, *SUGAR Implementation* (Mar. 4, 2025), available at: https://cdn.misoenergy.org/20250304%20IPWG%20Item%2005%20SUGAR%20Implementation682016.pdf MISO, *Liaison Report* (Mar. 4, 2025), available at: https://cdn.misoenergy.org/20250304%20IPWG%20Item%2002%20Liaison%20Report681818.pdf.

It should be noted that in the event that the Interconnection Customer withdraws and terminates its EGIA after execution of the EGIA by all parties or after EGIA is filed unexecuted, the Interconnection Customer will be liable for the Network Upgrades documented in the EGIA and corresponding Facilities Construction Agreements or Multi-Party Facilities Construction Agreements, including those Network Upgrades arising from the Affected System Study process. This will ensure that MISO will be able to expeditiously process the shovel ready ERAS Interconnection Requests while providing a protection mechanism to the existing Affected Systems coordination process. Additionally, ERAS Interconnection Requests will be subject to JTIQ requirements if they meet the criteria for inclusion in the JTIQ Screening Group or Participation Group on the same basis as projects in the DPP. Participation in JTIQ will serve as Affected System process with the Southwest Power Pool ("SPP").

Q. WILL THE AFFECTED SYSTEM STUDIES BE CONDUCTED IN A CLUSTER?

A. MISO will request that these studies be completed on a serial basis, but MISO is unable to control how an affected system will perform its own studies or on what timeframe. MISO will explicitly request that these be studied on a serial basis and MISO will transfer ERAS projects to the affected system serially and not as a cluster in order to enable the affected system to study the proposed projects serially. At the end of the day, only the affected system can determine for itself how and when it will carry out these studies. MISO will work with its seams partners to determine if changes to relative queue priority are necessary for ERAS. For those seams partners that utilize a close of study phase or decision point to establish queue priority, MISO will assert a queue priority date of when the ERAS quarterly study cycle is kicked off.

Q. DOES REQUIRING ERAS CUSTOMERS TO SIGN EGIAS WITHOUT POTENTIALLY HAVING THE AFFECTED SYSTEM STUDY RESULTS VIOLATE ORDER NO. 2023?

A. No. This is a separate limited process that was created outside the traditional DPP process and thus is out of scope of Order No. 2023, which is designed for cluster-based studies. ERAS is not a traditional queue process but is still consistent with the goals of Order No. 2023 which included enabling reforms of current generator interconnection procedures. Moreover, ERAS project participants are aware of the EGIA requirements prior to submitting their projects to the ERAS process. As MISO noted in its transmittal letter, because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined rule set rather than individual independent entity variations for the numerous differences between the cluster-based process outlined in Order 2023-2023-A and ERAS serial-based study approach.

D. A Transparent ERAS Process

Q. WILL MISO PUBLICIZE THE ERAS INTERONNECTION REQUESTS?

A. Yes. MISO commits to transparency in the refined ERAS process due to the critical nature of these projects. Similar to the EPR process, the ERAS information will be posted on the ERAS webpage located on the MISO public website, including the name of the Interconnection Customer that has submitted the ERAS Interconnection Request along with other details of the ERAS projects.

Q. WHAT INFORMATION DOES MISO PLAN TO POST ON ITS ERAS WEBPAGE?

A. On the newly created ERAS webpage, MISO plans to publish an informational guide regarding the requirements and process for participation in ERAS. After the first submission deadline for an ERAS quarterly study cycle, MISO plans to publish all ERAS projects that have been reviewed and accepted into the ERAS process. MISO will provide information similar to that found in its GI Interactive Queue for DPP projects, including items like the project number, request status, application in-service date, and fuel type.[47] And as previously explained in my testimony, MISO will additionally publish the non-confidential summary of the following information supplied by the applicant: the developer of the ERAS project, details of the need the ERAS project is addressing, what cap carve out was requested (if applicable), what LRZ region the project is located in, and a general description of what the load it is serving (i.e., a data center, manufacturing plant, a reliability need, etc.). MISO is also planning to publish what quarters each of the approved ERAS projects will be studied in.

Q. HOW DID YOU ACCOUNT FOR OPEN ACCESS REQUIREMENTS WHEN DEVELOPING THE ERAS PROCESS?

A. The ERAS requirements are facially neutral, fuel agnostic and allow for the potential inclusion of any resource regardless of technology. These are shovel ready projects to meet

[47] *MISO GI Interactive Queue*, last updated June 5, 2025, available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

an urgent resource adequacy and/or reliability need within the MISO footprint. MISO also expanded who could apply to ERAS to include a wide variety of applicants.

ERAS Interconnection Requests will be subject to more stringent criteria than projects entering the generator interconnection queue. MISO's ERAS requirements will inevitably limit entry which strikes a reasonable balance between allowing project developers to help address the urgent reliability needs of the MISO footprint, while avoiding an influx of projects that could overwhelm the normal DPP queue and lead to further delays, exacerbating the current inability of projects to come online.

Q. WHAT ARE THE BENEFITS OF ESTABLISHING AN ERAS PROCESS?

A. If the proposed temporary requirements for the refined ERAS process are adopted, MISO expects to comprehensively address significant near-term resource adequacy and reliability concerns in the MISO footprint. ERAS is a temporary process designed to help speed up the time to obtain an executed EGIA so urgent reliability projects can be built more quickly until the DPP interconnection queue process improved timeliness takes effect. The queue will remain the standard way to add new resources to the system; ERAS is a temporary and targeted process to complement the generator interconnection queue process. With ERAS, MISO will be able to efficiently and effectively address near-term resource adequacy and/or reliability needs with specific projects that are tied to those needs.

IV. CONCLUSION

Q. IN YOUR OPINION, IS MISO'S FILING JUST AND REASONABLE?

A. Yes. This Filing addresses certain specific needs that MISO, the state Commissions, and the stakeholder process identified. To ensure that MISO is on the right track to resolving its resource adequacy shortfall potential, MISO requests that the Commission approve this

proposal. The proposed Tariff revisions enable MISO to take the necessary steps to ensure reliability on the Transmission System.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Affidavit of Andrew Witmeier

COUNTY OF HAMILTON)

)

STATE OF INDIANA)

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Andrew Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 4th day of June, 2025.

Kandi Hahn

KANDI HAHN
Notary Public, State of Indiana
Marion County
Commission Number NP0740038
My Commission Expires
March 23, 2030

NOTARY PUBLIC SEAL INDIANA

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 122
GridLab Report

1

GridLab Analysis: Department of Energy Resource Adequacy Report



Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes th[illegible]**

the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S. Energy Information Administration

Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

Previous post
London Calling: How UK Grid Innovation ...


Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 123
Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY



Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

Nicholas Institute for Energy, Environment & Sustainability nicholasinstitute.duke.edu

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https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

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The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the Duke Climate Commitment, which unites the university's education, research, operations, and external engagement missions to address climate challenges.

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

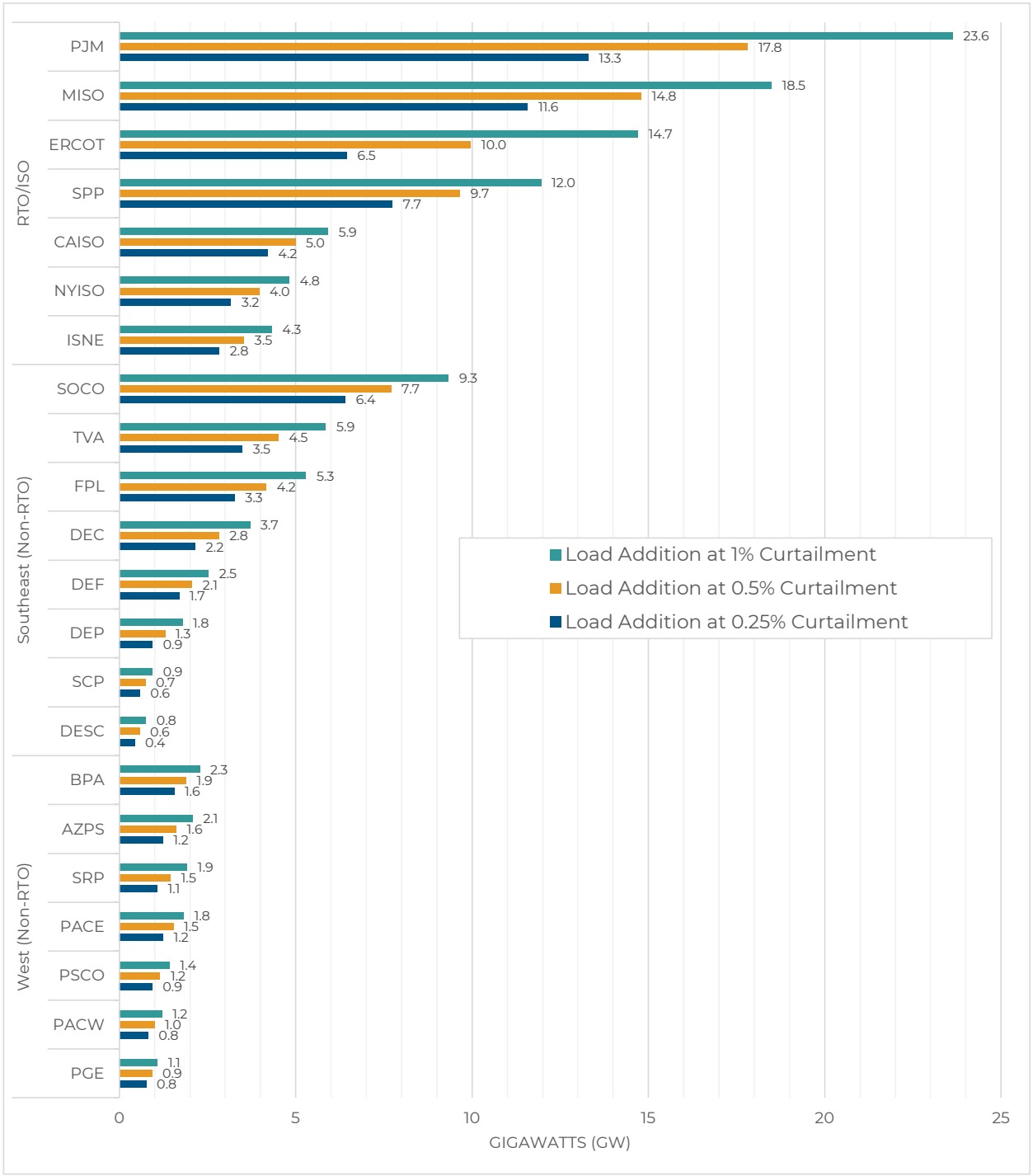
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

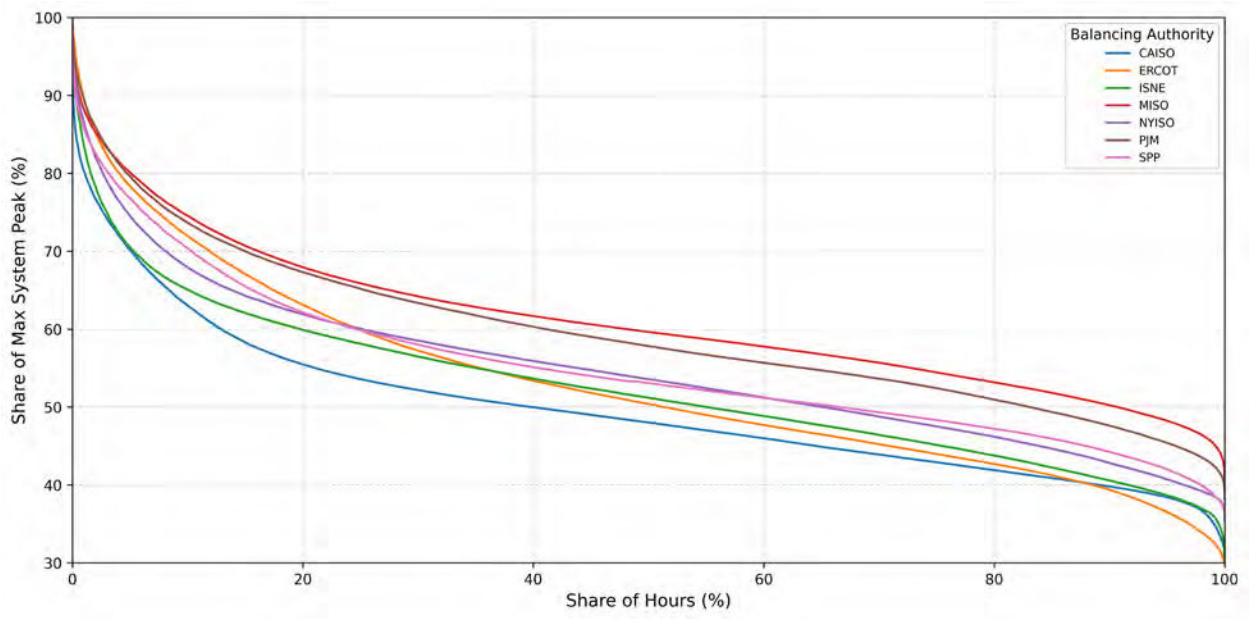
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

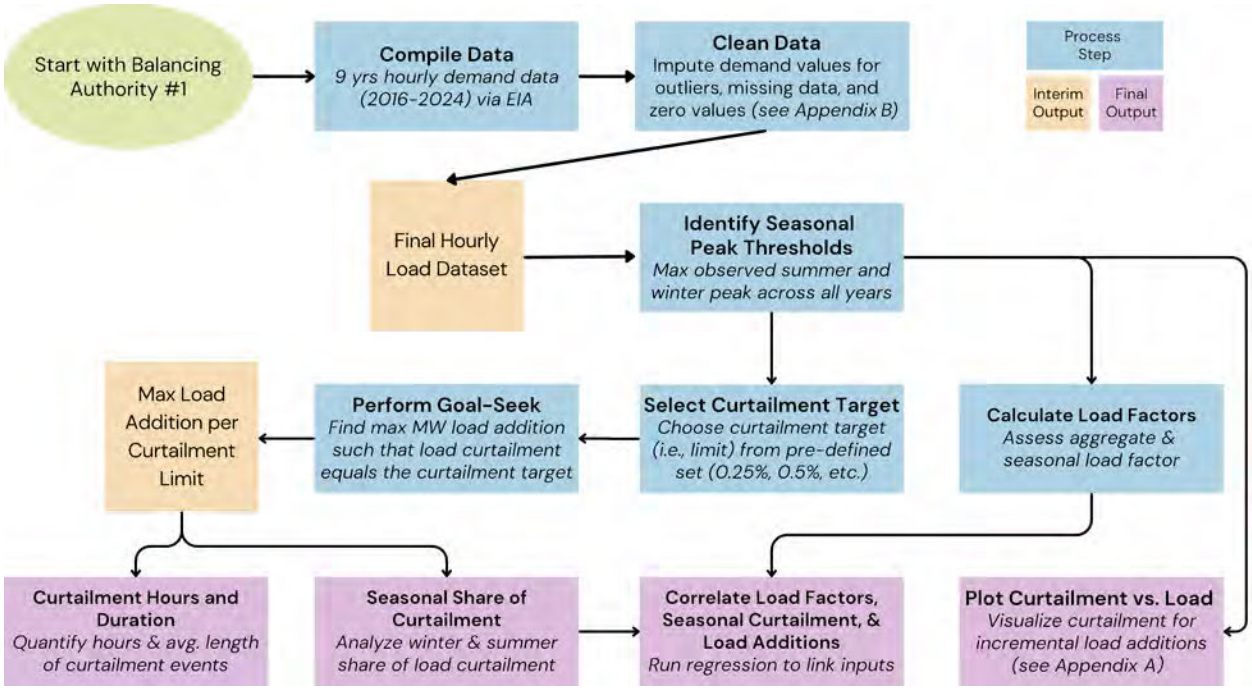
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

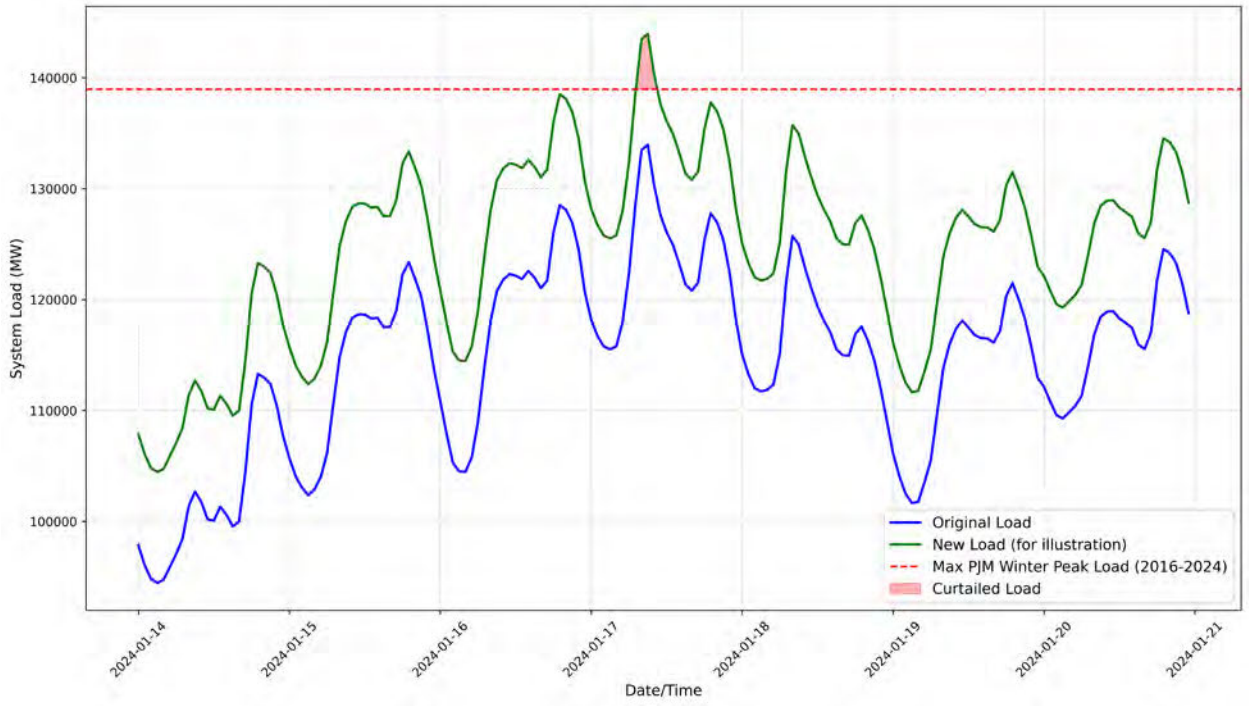
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

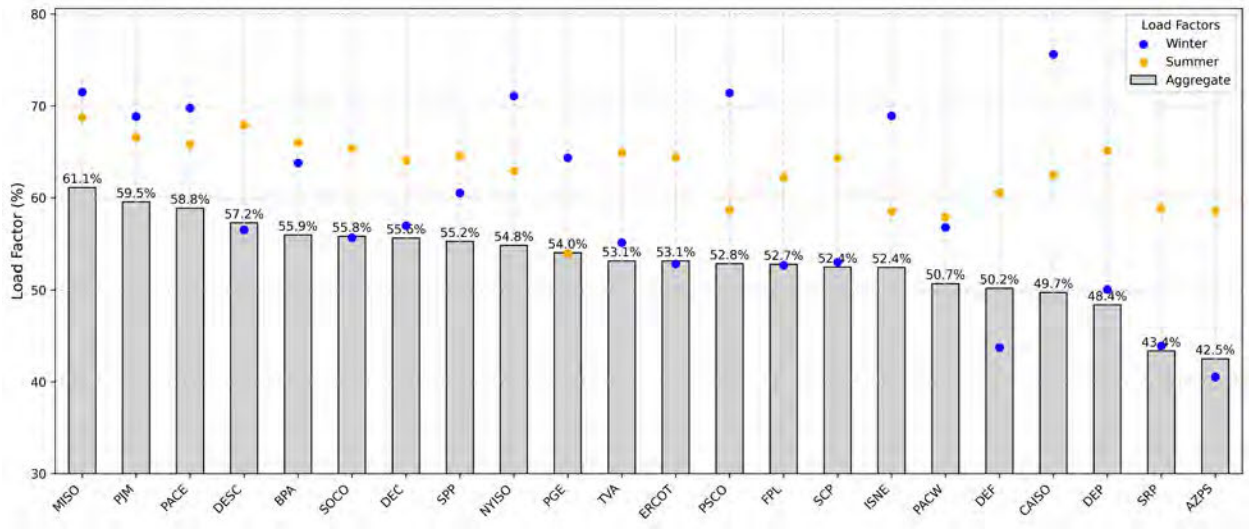
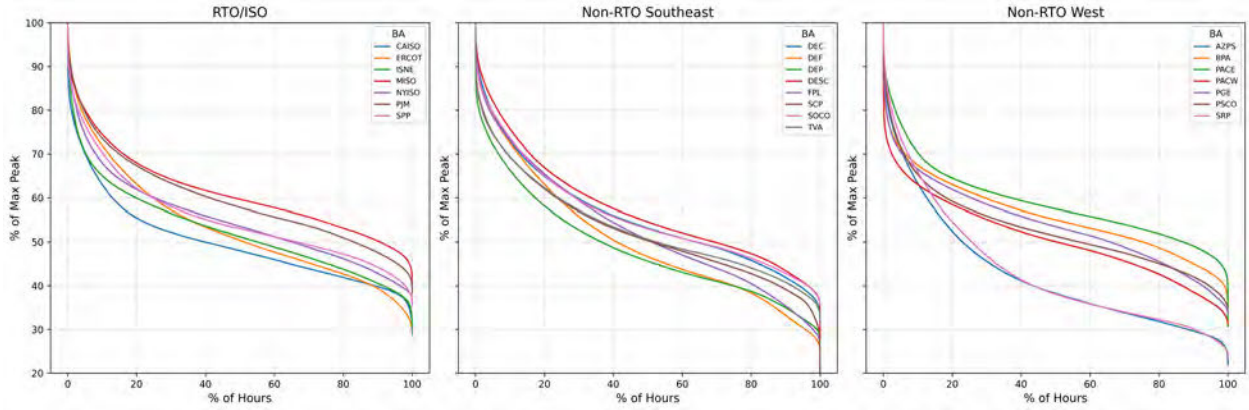


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

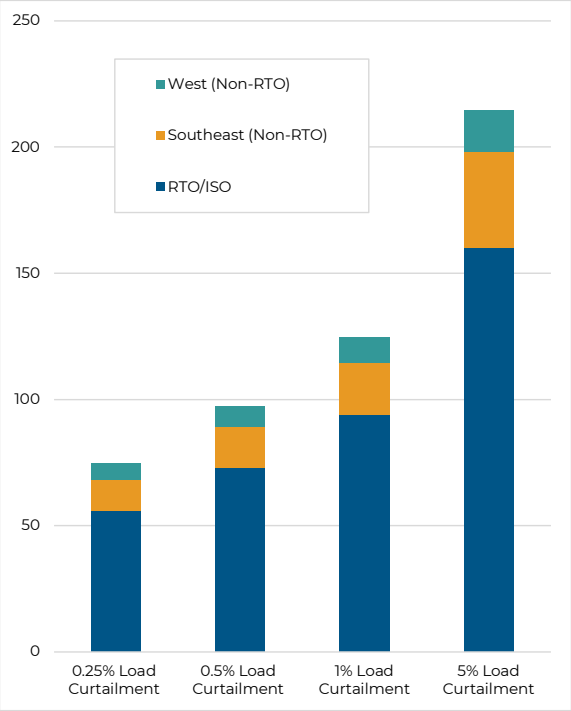


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

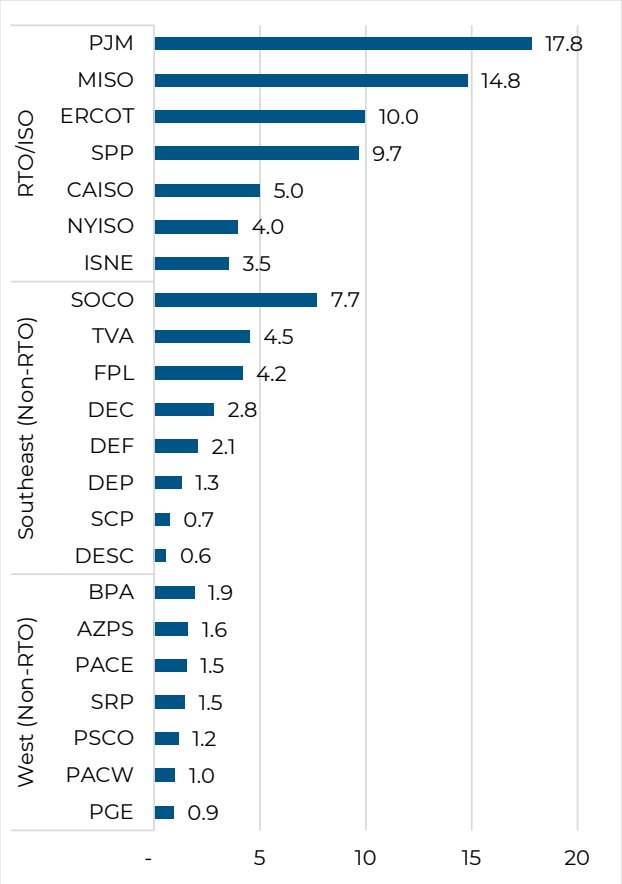
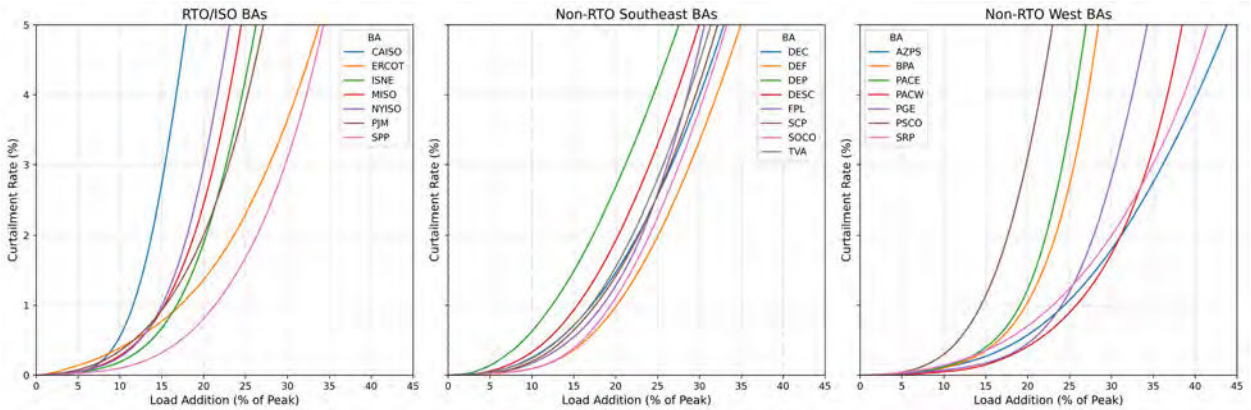


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

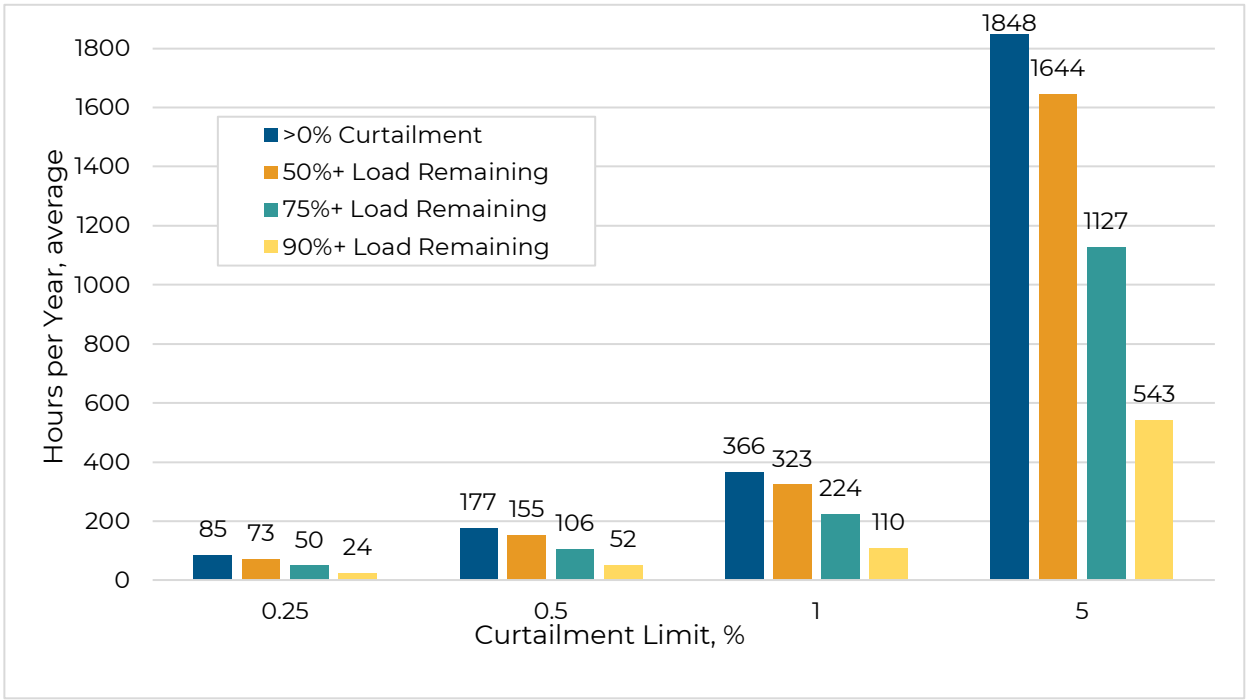
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

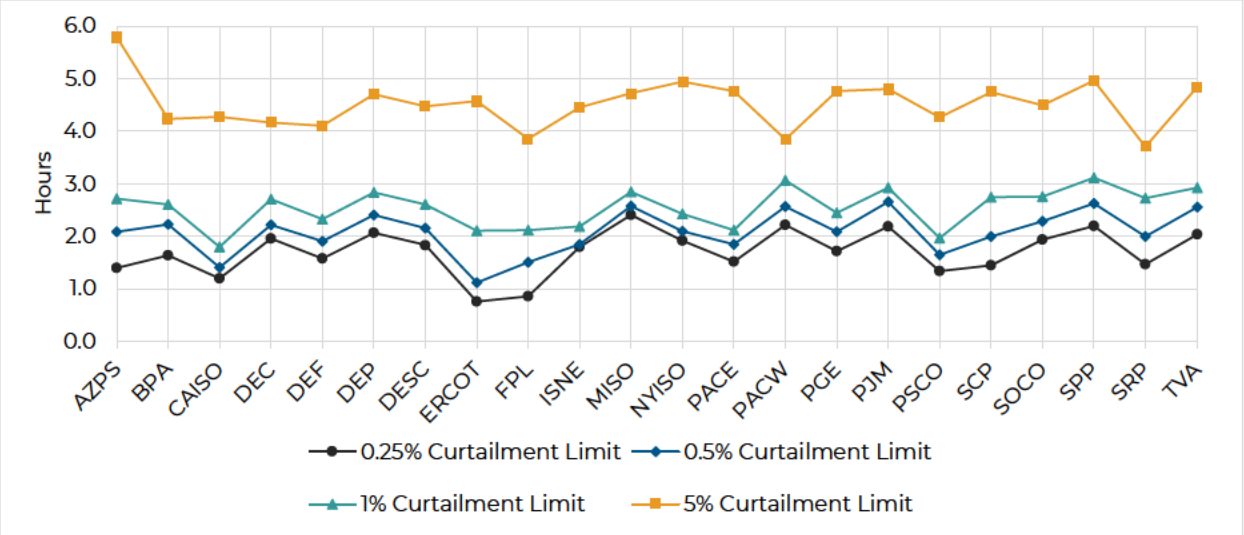
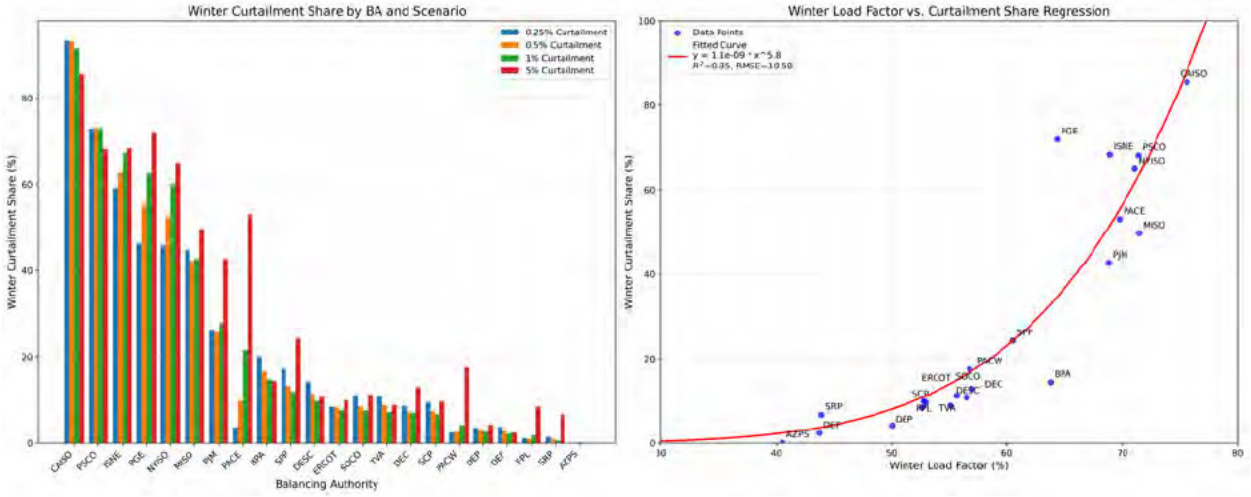


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

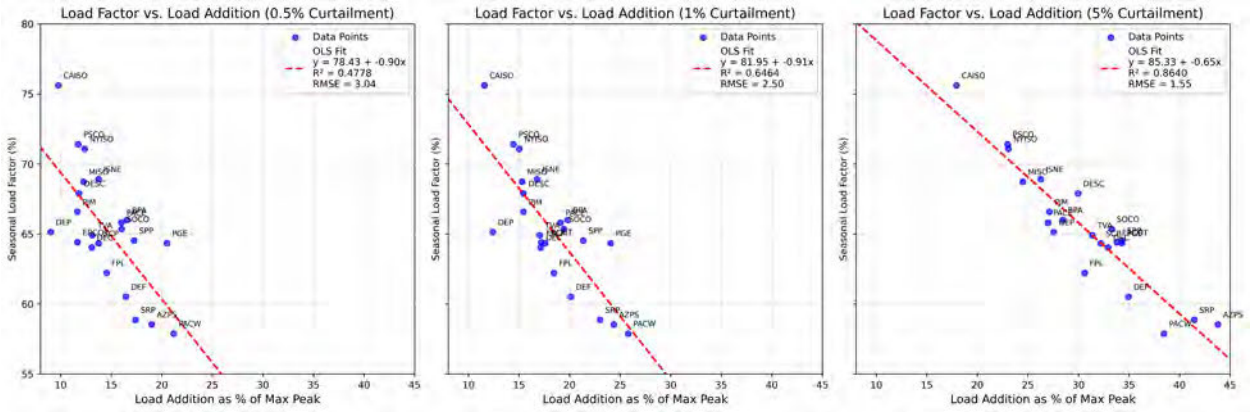
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

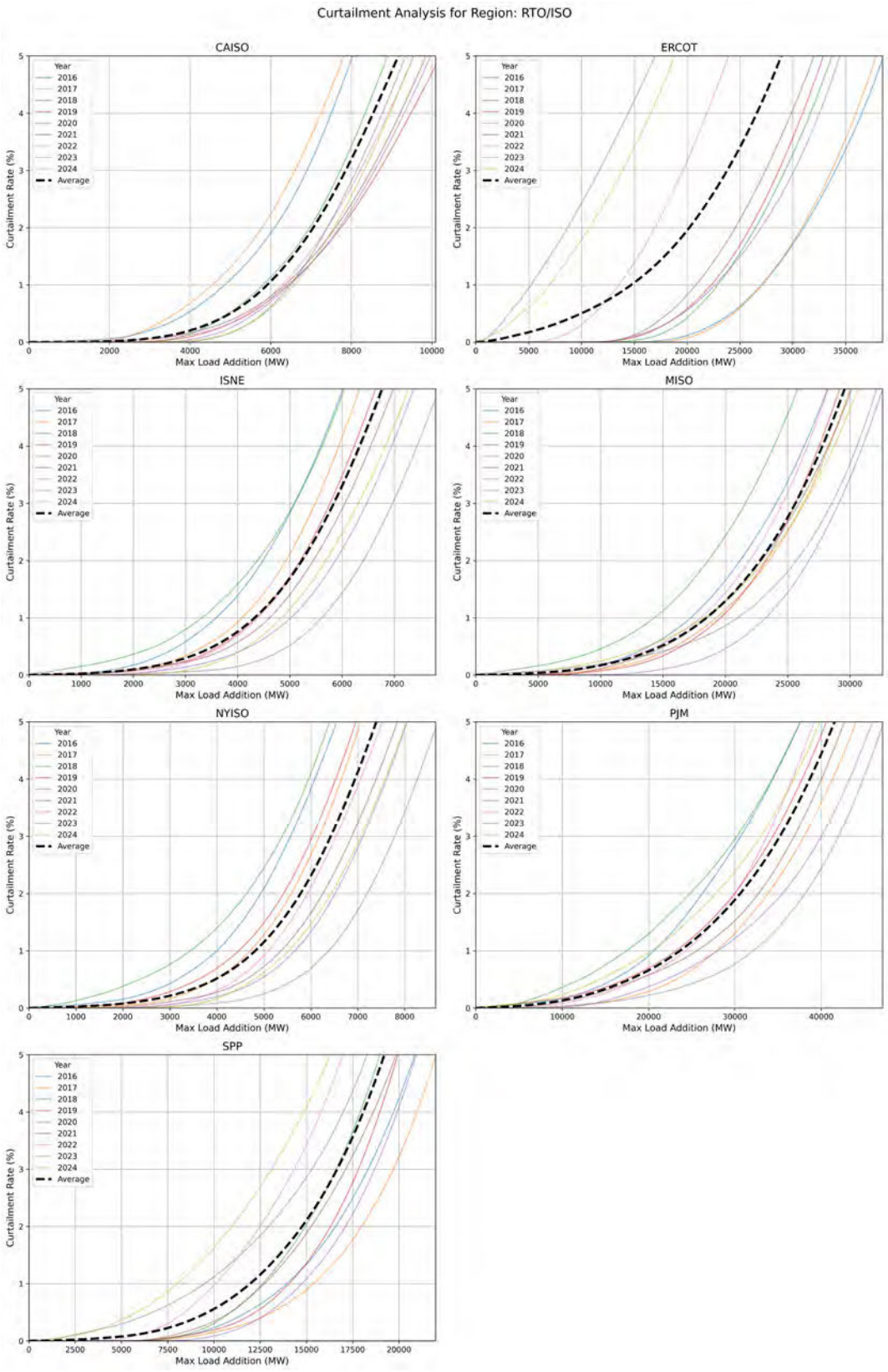


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

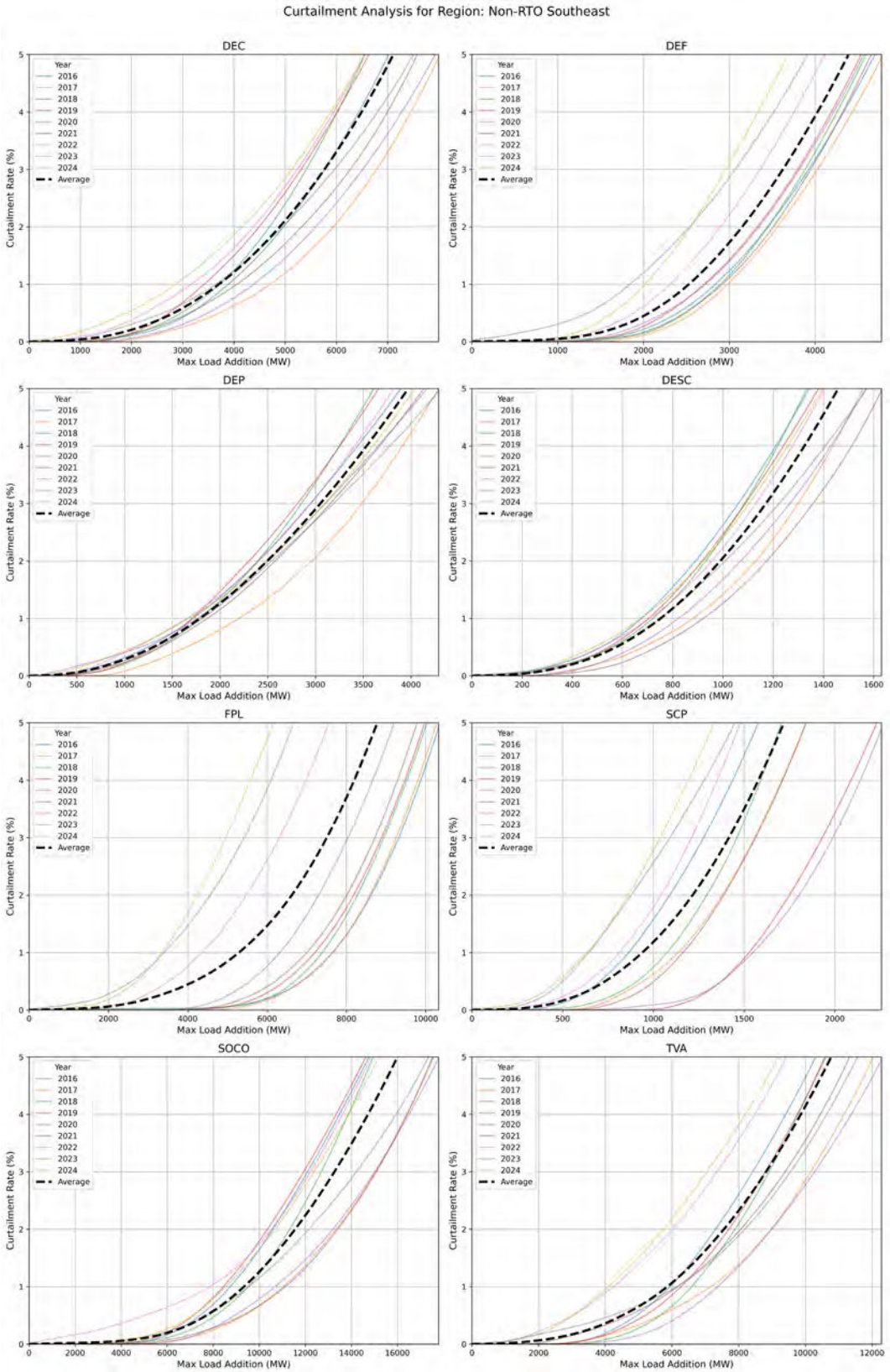
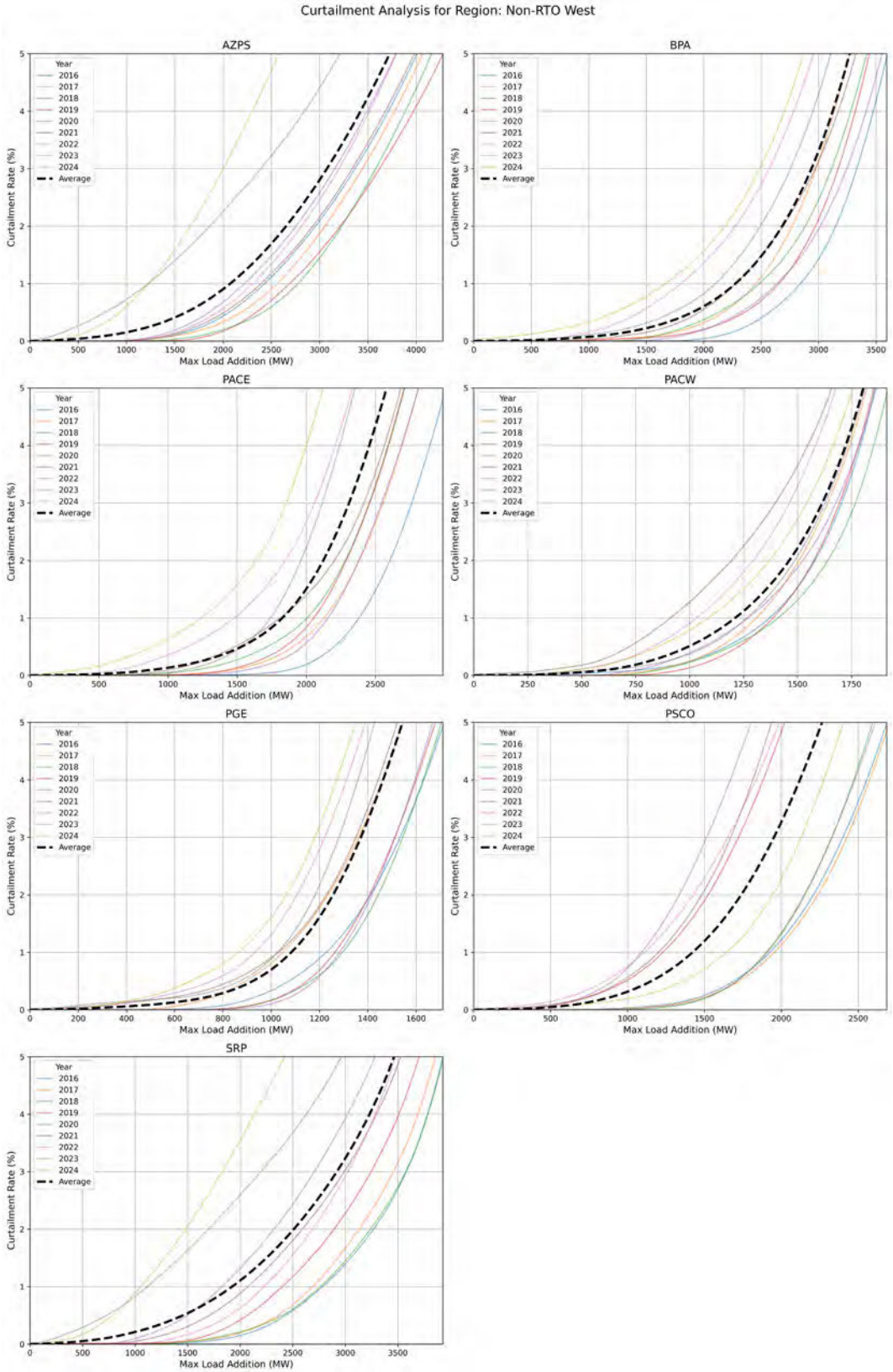


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L \cdot 8{,}760}\cdot 100\right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t \in T_y}\max(0, Demand_t + L - Threshold_t)}{L \cdot 8{,}760} * 100\right) = CurtailLimit$$