ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.5 FOR THE CONSTRUCTION OF TWO NATURAL GAS COMBUSTION TURBINES ("CTs") PROVIDING APPROXIMATELY 460 MW OF BASELOAD CAPACITY ("CT PROJECT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.4 FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("COMPLIANCE PROJECTS"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS THROUGH CEI SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM ("ECA"); (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS AND (B) POST-IN-SERVICE CARRYING CHARGES, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CT PROJECT AND COMPLIANCE PROJECTS UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) IN THE EVENT THE CPCN IS NOT GRANTED OR THE CTs OTHERWISE ARE NOT PLACED IN SERVICE, AUTHORITY TO DEFER, AS A REGULATORY ASSET, COSTS INCURRED IN PLANNING PETITIONER'S 2019/2020 IRP AND PRESENTING THIS CASE FOR CONSIDERATION FOR FUTURE RECOVERY THROUGH RETAIL ELECTRIC RATES; (7) ONGOING REVIEW OF THE CT PROJECT; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CT PROJECT AND COMPLIANCE PROJECTS ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ.*, AND 8-1-8.5-1 *ET SEQ.*	)	**CAUSE NO. 45564** **APPROVED: JUN 28 2022**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Stefanie N. Krevda, Commissioner
Jennifer L. Schuster, Senior Administrative Law Judge

On June 17, 2021, Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner" or "CEI South") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking, among other relief, a certificate of public convenience and necessity ("CPCN") for two new natural gas combustion turbines ("CTs") providing 460 megawatts ("MW") of capacity ("CT Project") pursuant to Ind. Code ch. 8-1-8.5, CPCNs for certain environmental projects related to a subset of Petitioner's generation facilities pursuant to Ind. Code ch. 8-1-8.4, and associated ratemaking and accounting treatment for these projects.

Also on June 17, 2021, Petitioner filed the testimony, attachments, and, for certain witnesses, workpapers, of the following (all of whom are employees of Petitioner except as otherwise noted): Steven C. Greenley, Senior Vice President of Generation Development for CenterPoint Energy, Inc. (Petitioner's Exhibit 1); Wayne D. Games, Vice President, Power Generation Operations (Petitioner's Exhibit 2); Erin M. Carroll, Senior Vice President, PowerAdvocate (Petitioner's Exhibit 3); Angila M. Retherford, Vice President, Environmental and Corporate Responsibility (Petitioner's Exhibit 4); Matthew A. Rice, Director of Indiana Electric Regulatory and Rates (Petitioner's Exhibit 5); Nelson Bacalao, Principal Consultant, Siemens PTI (Petitioner's Exhibit 6); Jason A. Zoller, Chief Engineer, Black & Veatch ("B&V") (Petitioner's Exhibit 7); Paula J. Grizzle, Director of Gas Supply and Portfolio Optimization (Petitioner's Exhibit 8); Kara R. Gostenhofer, Director and Assistant Controller (Petitioner's Exhibit 9); Rina H. Harris, Director of Energy Solutions and Business Services (Petitioner's Exhibit 10); and F. Shane Bradford, Director of Power Supply Services (Petitioner's Exhibit 11).

Petitions to intervene were filed by the Citizens Action Coalition of Indiana, Inc. ("CAC"), CenterPoint Energy Indiana South Industrial Group ("Industrial Group"), Sierra Club, Hoosier Chapter ("Sierra Club"), and Sunrise Coal, LLC ("Sunrise Coal"), all of which were granted.

A public field hearing was held in Evansville, Indiana on October 13, 2021, during which members of the public presented testimony related to the relief sought in this Cause.

On November 19, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony of its witnesses, all of whom are employees of the OUCC's Electric Division: Peter M. Boerger, Ph.D., Senior Utility Analyst (Public's Exhibit 1); Anthony A. Alvarez, Utility Analyst (Public's Exhibit 2); Cynthia M. Armstrong, Senior Utility Analyst (Public's Exhibit 3); and Kaleb G. Lantrip, Utility Analyst (Public's Exhibit 4). Also on that date, intervenors filed the testimony and attachments of their witnesses, including the following: Michael P. Gorman, Managing Principal, Brubaker and Associates, Inc. (Industrial Group's Exhibit 1); Kerwin L. Olson, Executive Director of CAC (CAC's Exhibit 1); Anna Sommer, Principal, Energy Futures Group (CAC's Exhibit 2); Josh Keeling, Director, Cadeo Group (CAC's Exhibit 3); Michael

Goggin, Vice President, Grid Strategies, LLC (Sierra Club's Exhibit 1); Emily S. Medine, Principal, Energy Ventures Analysis, Inc. (Sunrise Coal's Exhibit 1); Michael J. Nasi, Partner, Jackson Walker LLP (Sunrise Coal's Exhibit 2); and Tommy L. Sutton, Engineering Manager, Sunrise Coal, LLC (Sunrise Coal's Exhibit 3).

The OUCC also filed written consumer comments with its prefiled evidence on November 19, 2021 (Public's Exhibit 5) and additional consumer comments on January 19, 2022 (Public's Exhibit 6). The CAC filed supplemental testimony of Ms. Sommer (CAC's Exhibit 4) on November 22, 2021, and Sunrise Coal filed supplemental testimony of Mr. Sutton (Sunrise Coal's Exhibit 4) on December 17, 2021.

On December 20, 2021, CEI South filed the rebuttal testimony, attachments, and workpapers of Mr. Greenley (Petitioner's Exhibit 1-R), Mr. Games (Petitioner's Exhibit 2-R), Ms. Retherford (Petitioner's Exhibit 4-R), Mr. Rice (Petitioner's Exhibit 5-R), Ms. Grizzle (Petitioner's Exhibit 8-R), Ms. Gostenhofer (Petitioner's Exhibit 9-R), Ms. Harris (Petitioner's Exhibit 10-R), Mr. Bradford (Petitioner's Exhibit 11-R) and Steven A. Hoover, Petitioner's Regional Director of Gas Engineering (Petitioner's Exhibit 12-R).

On January 14, 2022, the Commission issued a docket entry requesting that Petitioner provide certain attachments to its Engineering, Procurement, and Construction ("EPC") Agreement filed as Attachment WDG-R4 to Petitioner's Exhibit 2-R. Petitioner filed its response to this docket entry on January 18, 2022 (Petitioner's Exhibit 13).

On January 21, 2022, the Presiding Officers granted the unopposed motion filed by intervenors seeking a remote evidentiary hearing due to the ongoing COVID-19 pandemic.

The evidentiary hearing in this matter commenced on January 26, 2022 at 10:30 a.m. via WebEx, at which time evidence was offered by CEI South, the OUCC, CAC, Sierra Club, Sunrise Coal, and the Industrial Group. Among the evidence offered at the hearing were certain stipulations between Petitioner and various intervenors with respect to certain facts and admissibility of specific exhibits.

Based upon the applicable law and the evidence of record, the Commission finds:

1. <u>Notice and Jurisdiction</u>. Due, legal, and timely notice of the public field hearing and evidentiary hearing in this Cause was given and published as required by law. Petitioner 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. Pursuant to Ind. Code chs. 8-1-8.4 and 8-1-8.5, Petitioner may seek Commission approval of the CPCNs requested in this Cause. Under applicable law, the Commission has jurisdiction over the relief sought by Petitioner in this Cause.

2. <u>Petitioner's Characteristics</u>. Petitioner is a public utility incorporated under Indiana law and has its principal office at 211 NW Riverside Drive, Evansville, Indiana. CEI South owns, operates, manages, and controls, among other things, plant, property, equipment, and facilities which are used and useful for the production, storage, transmission, distribution, and furnishing of electric service to approximately 145,000 electric consumers in southwestern

Indiana. Its service territory is spread throughout Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick, and Spencer counties.

3. **<u>Background</u>.** In Cause No. 45052, filed on February 20, 2018, CEI South requested, among other things, approval of a CPCN for a new 850 MW combined gas cycle turbine ("CCGT") generation facility to be located at its A.B. Brown generating station located on the Ohio River in Posey County, Indiana ("A.B. Brown" or "Brown"). On April 24, 2019, we issued our final order in that case ("45052 Order"), which, among other things, denied CEI South's requested CPCN for the CCGT and discussed the reasons for the denial. The 45052 Order explained in detail how CEI South could improve its planning prior to future CPCN requests. We noted that, while CEI South's request in Cause No. 45052 was "'consistent' with its 2016 [Integrated Resource Plan ("IRP")], the subsequent modeling for this case effectively screened out multiple less-expensive alternatives." 45052 Order at 26. We also found CEI South's risk analysis to be inadequate for multiple reasons, including its failure to update the risk modeling from its 2016 IRP prior to filing and failure to account for material risks associated with the preferred portfolio identified in the 2016 IRP. *Id.* at 27.

In addition, we stated in the 45052 Order that CEI South failed to consider that "[t]he 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[,]" making us "hard pressed to see how reliance on one facility for so much of the [CEI South] system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change." *Id.* at 28. We concluded that CEI South's request

> 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 [CEI 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.

Id.

4. **<u>Relief Requested</u>.** In this Cause, CEI South has requested the Commission issue a CPCN pursuant to Ind. Code ch. 8-1-8.5 for two CTs to be located at the A.B. Brown site, approve associated ratemaking and accounting treatment for the two CTs, establish a depreciation rate for the CT Project, and grant its request for ongoing review of the CT Project. If the CPCN for the two CTs is not granted or the CTs are otherwise not placed in service, CEI South requests that the Commission authorize it to defer, as a regulatory asset, costs incurred in planning its 2019/2020 IRP and presenting this case for consideration, for future recovery through retail electric rates.

CEI South has also requested the Commission issue CPCNs pursuant to Ind. Code ch. 8-1-8.4 for the construction of equipment and facilities necessary to comply with the United States Environmental Protection Agency's ("EPA") Coal Combustion Residuals ("CCR") rule for the handling and disposal of dry ash (the "Dry Ash Compliance Project") and to construct two new small ponds (one at A.B. Brown and one at Petitioner's F.B. Culley generating station in Warrick County, Indiana ("Culley")) to handle coal-pile runoff, flue gas desulfurization ("FGD") wastewater, and other flows such as stormwater and landfill leachate in compliance with the EPA's CCR rule (the "Pond Compliance Project") (collectively with the Dry Ash Compliance Project, the "CCR Compliance Projects"). CEI South also has requested that the Commission approve accounting and ratemaking treatment for the CCR Compliance Projects and establish a depreciation rate for the CCR Compliance Projects.

5. The Parties' Evidence.

A. Petitioner's 2019/2020 IRP. Mr. Rice described how CEI South developed the portfolios modeled in the 2019/2020 IRP. He testified that, following the 45052 Order, CEI South, with the help of Burns & McDonnell, conducted an all-source request for proposals ("All-Source RFP") to gather resource availability and pricing information for various resources, including resources such as solar, solar plus storage, and standalone storage. Mr. Bradford testified that 22 individual respondents submitted complete responses to the All-Source RFP, resulting in 110 proposals, 91 of which were for projects located in Indiana. The proposals included eight for battery storage, two for coal, seven for combined cycle, one Load Modifying Resource ("LMR")/Demand Response ("DR"), 57 solar, 19 solar plus storage, three system energy, and 13 wind.

Mr. Rice summarized the 15 optimized portfolios examined and explained the carbon dioxide and gas prices used within the scenario modeling. Each portfolio was evaluated utilizing simulated dispatch in the reference case, which led to the exclusion of several portfolios from further consideration. The remaining ten portfolios were then evaluated using a balanced scorecard approach. From this analysis, CEI South identified the Preferred Portfolio, which includes a diverse mix of resources including energy efficiency, wind resources, solar and solar plus storage, and the CT Project. Mr. Rice also explained Petitioner's Generation Transition Plan and how the Preferred Portfolio offers future flexibility, should the future turn out different than expected. He testified that CEI South incorporated stakeholder input throughout the process.

Dr. Bacalao testified that Siemens PTI developed and managed Petitioner's IRP modeling (including some input development), strategic consulting, participation in the stakeholder process, and scorecard development. He stated that Siemens PTI used a balanced scorecard approach to illustrate the reasonableness of the Preferred Portfolio.

Mr. Rice testified that the Preferred Portfolio performed well across multiple risk factors in the balanced scorecard and stated that the Preferred Portfolio avoids long-term reliance on the capacity market or heavy reliance on emerging technology. He opined that the fast start and ramping capability of the two CTs that are part of the Preferred Portfolio allows for high penetration of low-cost renewable energy resources, which were consistently selected in all portfolios, regardless of potential future events. He noted that the CT Project will allow CEI South to build renewable resources with the confidence that dispatchable resources such as the CTs will be available when needed, particularly in winter months where multi-day periods of cloud cover and no wind are possible.

The OUCC's position is that refueling A.B. Brown with natural gas is preferable to the proposed CTs. Dr. Boerger testified that gas conversions can be completed at a very low capital cost compared to the cost of a new CT. He discussed the net present value of revenue requirements ("NPVRR") values for the gas conversion and presented his analysis of CEI South's modeled operation and maintenance ("O&M") costs for gas-converted units. He opined that NPVRR values for the gas conversion portfolios incorporate a significant overestimation of O&M costs, based on the reduction in O&M costs AES Indiana experienced after converting its Harding Street Station units to burn gas.

Testifying on behalf of the CAC, Ms. Sommer stated that she found errors in CEI South's 2019/2020 IRP and opined that correcting for these errors would result in the selection of a plan that is lower cost, includes more renewables and battery storage, and avoids the construction of the CT Project. She explained she had transparency concerns with CEI South's modeling because she could not access all of the Siemens PTI data to run her own modeling. Even though CEI South and Siemens provided an analyst to perform additional Aurora simulations, Ms. Sommer did not find this to be a satisfactory resolution to her transparency concerns. She questioned the veracity of CEI South's industrial sales and load forecast and suggested the Commission add a condition that if the additional industrial load upon which the IRP modeling was based fails to materialize, the Commission should disallow certain costs.

Ms. Sommer also testified that her analysis of additional modeling runs performed by Siemens PTI on behalf of CAC, CAC High Tech, and CAC Renewables by 2030 supported using a combination of DR, solar, wind, and storage to replace retiring coal. Ms. Sommer also raised concerns with the stochastic gas price analysis, again citing an inability to independently verify the modeling results without full access to all data.

Mr. Gorman, testifying for the Industrial Group, opined that CEI South has not demonstrated that constructing two CTs to serve its capacity needs is reasonable, arguing that the 2019/2020 IRP did not demonstrate that the capacity offered by both CTs would be needed until 2033. He acknowledged that CEI South has reported some increases in projected industrial load, which may support the need for additional capacity relative to the IRP load studies, but noted that CEI South has not rerun its IRP to show these new load changes. He also opined that potential changes since the IRP (such as increased gas prices) may affect the reasonableness of building the CT Project.

Testifying for the Sierra Club, Mr. Goggin opined that, if Petitioner's 2019/2020 IRP were conducted today using updated cost assumptions, the modeling would likely select even greater amounts of wind, solar, and storage instead of gas capacity. Mr. Goggin explained why he believes batteries have superior technical capabilities to gas CTs and opined that CEI South's increasing reliance on gas poses significant economic and reliability risks. He opined that CEI South's 2019/2020 IRP called for significantly more solar and storage capacity. He opined that imports and exports are an efficient tool for integrating large amounts of wind and solar generation and can help meet reliability needs, including during extreme weather events. He also testified that the capacity value of renewable and storage resources is understated. He also noted economic and reliability risks associated with dependence on natural gas and CEI South's plan to eventually operate the CT Project on hydrogen. He recommended the Commission deny the CPCN for the CT Project.

Ms. Medine, testifying on behalf of Sunrise Coal, opined that, due to changes in the natural gas and power markets after the 2019/2020 IRP, continued use of the A.B. Brown plant to burn coal for several more years is a superior alternative to the proposed CT Project and a better exit ramp to incorporating more renewable options in Petitioner's generation portfolio.

On rebuttal, Mr. Rice responded to the non-utility parties' concerns with gas prices, stating that the Preferred Portfolio performed well on multiple objectives, including cost, which considered the full range of probable gas price forecasts. He testified that recently volatile gas prices appear to be returning to expected levels.

Regarding criticisms of CEI South's load forecasts, Mr. Rice stated that CEI South has lost nearly all industrial DR since filing the 2019/2020 IRP. He also disagreed with Mr. Goggin's testimony regarding relying on imports and exports for reliability, noting that CEI South, as a North American Electric Reliability Corporation ("NERC") Load Serving Entity ("LSE") within the Midcontinent Independent System Operator ("MISO") footprint, has responsibility to provide adequate resources to meet its load. He opined that, if MISO and CEI South relied solely upon imports to serve the system load during peak times, CEI South would subject its customers to significant reliability and price risks. He stated that inadequate transmission system voltage can cause partial and cascading grid collapse, but the CT Project alleviates this issue.

Mr. Rice discussed the OUCC's proposal that CEI South convert the existing A.B. Brown units to natural gas, noting that Dr. Boerger ultimately agreed in deposition that his calculations show that gas conversion will cost more than the Preferred Portfolio. Mr. Rice explained how the OUCC's position that the cost of the conversion at A.B. Brown could be $78.2 million less was miscalculated. He also discussed how the capital cost recovery for the CTs was not assumed to have a 100-year life, as implied in Dr. Boerger's testimony; CEI South assumed a 30-year life. Mr. Rice also stated that Dr. Boerger was incorrect to estimate the depreciation rate by subtracting the discount rate from the capital cost recovery factor. He testified that the capital cost recovery factor is a multiplier that is used to determine the annuity that needs to be recovered to obtain a return on the capital invested and repay the original capital. He stated the 8.64% reported corresponds to a 30-year life and a discount rate of 7.71%. Thus, Mr. Rice concluded that the OUCC's calculation of a $47.8 million impact is incorrect. Mr. Rice stated that the impact, when correctly calculated, is zero. Mr. Rice also responded to Dr. Boerger's statement that the cost of removal was not included in the Preferred Portfolio, noting that it was included in confidential attachments to Dr. Boerger's own testimony.

Mr. Bradford stated that, although Mr. Alvarez testified that a refueled A.B. Brown would receive the same nameplate capacity as it had when run on coal, MISO's Independent Market Monitor ("IMM") had made different recommendations for MISO capacity accreditation in the 2020 State of the Market Report ("IMM Report"). Mr. Bradford explained that the IMM ultimately recommended that MISO move away from unforced capacity ("UCAP"), because "it does not recognize that inflexible resources with long lead times are less valuable than more flexible resources" and "[t]his reflects reality because MISO often does not see tight conditions coming day-ahead or many hours in advance, which causes long-lead time offline units to contribute less to overall reliability than online or quick start resources." Petitioner's Exhibit 11-R, Attachment FSB-R1 at 91; Petitioner's Exhibit 11-R at 22. He said that, under the IMM's recommended available capacity ("ACAP"), the nameplate capacity of a converted Brown would be approximately 25% lower than when it was run on coal.

Mr. Bradford disagreed with Mr. Gorman's testimony that the most recent IRP did not demonstrate that the capacity offered by both CTs would be needed until 2033, citing Table FSB-R2 attached to his rebuttal testimony, which shows a capacity deficit as early as 2028, requiring additional generation or capacity to meet CEI South's needs.

Mr. Bradford also responded to Mr. Goggin's assertion that CEI South should rely on capacity market purchases rather than the CTs to meet its capacity needs. He opined that Mr. Goggin incorrectly extrapolates MISO Planning Reserve Auction ("PRA") clearing prices as the future cost to CEI South to cover its capacity requirements. Mr. Bradford stated that MISO is fundamentally not a long-term capacity market, as evidenced by the fact that the auction for capacity during a given planning year running from June-May is conducted only a few months prior to the start of the planning year. The 2021 Organization of MISO States ("OMS") Survey Report shows Zone 6, including CEI South's service territory, as having the greatest potential capacity shortage across all zones in the 2026 outlook and as being critically dependent on potential new resources to meet local clearing requirements by 2026. To the extent potential new generation is critical to meeting its local resource requirements, the CTs are already included in the OMS survey results as part of the potential capacity needed to ensure reliability.

B. <u>CT Project</u>. Mr. Games testified that CEI South's generation portfolio heavily relies on coal generation, totaling 1,032 MW. He stated that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of CEI South's coal-fired units. Instead of running continuously, CEI South's coal-fired units are now cycled up and down throughout the day or are shut down altogether, decreasing unit efficiency, increasing wear and tear on the units, and enhancing environmental compliance risk. He testified that the A.B. Brown generation units, at a net 245 MW each, are among the smallest and least efficient coal units remaining in Indiana and do not provide the flexibility required to reliably provide the back-up for a large renewable portfolio in an economic manner.

Mr. Games testified on direct that the estimated cost of the CT Project was approximately $323 million; this estimate was updated on rebuttal to approximately $334 million following Petitioner's execution of the EPC contract with Kiewit Power Constructors Co. ("Kiewit") on November 30, 2021. He stated that the proposed two F-Class natural gas CTs would have an output of approximately 460 MW and would replace the A.B. Brown coal plant and support the 700-1,000 MW of solar and solar plus storage and 300 MW of wind in Petitioner's generation portfolio. He testified that CEI South considered a range of natural gas CT options, but found that the proposed F-Class turbines are among the most efficient units currently available in this class, with the lowest capital cost per kilowatt ("kW") versus other new natural gas options evaluated. He stated that the F-Class CTs together will be able to ramp up at a rate of 80 MW per minute.

Ms. Retherford discussed the federal regulations, such as Effluent Limitation Guidelines ("ELG"), CCR, and the cross-state air pollution rule ("CSAPR"), that impact CEI South's coal-generating units. She testified that CEI South must cease operations by December 31, 2023 to comply with the firm deadline for prohibition of fly ash transport by water under ELG. She explained that CEI South's Preferred Portfolio avoids additional incremental compliance costs for CCR and ELG at A.B. Brown by retiring the two coal-fired units and replacing them with renewables and the CT Project.

Mr. Bradford described how the CT Project fits within the overall capacity composition forecast for the MISO footprint and explained congestion impacts. He opined that, for consistent reliable generation to Indiana customers, renewable generation must be supported by dispatchable generation, such as the proposed CTs that have the ability to quickly ramp up and down. He stated that the CT Project will thus support renewables in CEI South's service territory and in and around MISO Zone 6.

Dr. Boerger opined that the OUCC's proposed alternative to the CT Project, refueling A.B. Brown with natural gas, would minimize capital outlays for CEI South customers, provide the dispatchable capacity CEI South indicates it needs, and provide needed flexibility. Mr. Alvarez also testified that refueling the A.B. Brown units would require low capital outlay, which would serve to protect ratepayer interests in existing assets. Ms. Armstrong explained that gas conversion will qualify for the same air permits and emissions netting benefits as the new gas CTs.

Mr. Olson of the CAC testified that CEI South has some of the highest bills in the country and that the CT Project is not in the best interest of ratepayers. Ms. Sommer opined that the gas pipeline proposal is oversized relative to its need. Mr. Keeling testified that untapped DR potential in CEI South's electric service territory exists, and he suggested changes to CEI South's interruptible tariff language necessary to access this untapped potential.

As noted above, Mr. Gorman testified on behalf of the Industrial Group that CEI South has not demonstrated that both CTs would be needed prior to 2033.

Testifying on behalf of the Sierra Club, Mr. Goggin opined that CEI South failed to correctly account for declining electricity demand, the capacity surplus in Indiana and elsewhere in the MISO footprint, and the large capacity value contributions of renewable and storage resources in proposing the CT Project. He argued that the extremely low capacity factors in CEI South's modeling indicate that the proposed CT Project, and particularly the second proposed CT, are uneconomic and not needed for reliability. He also noted a risk that one or both of the proposed CTs will become stranded assets.

Ms. Medine, testifying on behalf of Sunrise Coal, noted that the viability of the CT Project is unclear due to the Federal Energy Regulatory Commission ("FERC") requirement for an environmental impact statement ("EIS") for the pipeline project. She interpreted the FERC's decision to prepare an EIS for the pipeline extension as an apparent repudiation of Petitioner's position that the CT Project would have a net benefit on the environment (allowing for the retirement of A.B. Brown's coal units) and that the CT Project is necessary for CEI South to serve its customers. Ms. Medine also stated that continuing to burn coal at A.B. Brown would not require expensive scrubber replacement and ELG compliance investment, as claimed by Petitioner, as long as coal burning ends by 2028. She opined that the only impediment to continuing to burn coal at A.B. Brown for several more years relates to CCR compliance.

Mr. Nasi, also on behalf of Sunrise Coal, opined that CEI South did not examine all reasonable alternatives in its filing to the EPA for an extension to continue to use the Brown pond past the original April 2021 cease disposal date and described additional alternatives which he said would allow A.B. Brown to continue operation through October 2026. He testified that the timing for the cessation of the operation of the boilers depends on the amount of time it takes to complete closure of the surface impoundment.

On rebuttal, Mr. Greenley testified that, if CEI South's request for a CPCN for the CT Project is denied, CEI South risks losing, among other things, the benefits of the signed EPC contract for the CT Project, the interconnection rights from building new generation at the A.B. Brown site, and the benefits of environmental netting. He opined that a denial would subject CEI South customers to risk from a higher cost portfolio and potentially volatile swings in the price of energy and capacity while awaiting further analysis.

Mr. Games explained why the OUCC's alternate proposal of refueling A.B. Brown with natural gas is not viable, stating that refueling will not provide the dispatchable power needed to ensure a reliable supply of electricity as CEI South and others in MISO's footprint transition generation to renewable energy resources. He noted that, while there are many benefits to adopting renewable energy, the intermittent nature of renewable resources necessitates incorporating resources like the proposed CTs that can react and ramp up quickly to provide power when renewable resources cannot. Mr. Rice identified a number of errors in Dr. Boerger's analyses leading to the OUCC's recommendation that CEI South refuel A.B. Brown with natural gas.

Ms. Retherford discussed why Sunrise Coal's proposal to burn coal at A.B. Brown beyond October 2023 is not feasible, noting that this would require significant expenditures for environmental compliance and the termination of the existing A.B. Brown Ash Pond Compliance Plan approved by the Commission in Cause No. 45280. She opined that Sunrise Coal's proposal oversimplifies the extension mechanisms provided in the CCR Part A Reconsideration Rule and fails to consider the full suite of environmental compliance requirements applicable to the A.B. Brown coal units.

Ms. Retherford also addressed FERC's decision to prepare an EIS for the gas lateral to serve the CT Project, stating that Ms. Medine's interpretation of that decision as a repudiation of the need for the CT Project is incorrect. Ms. Retherford testified that FERC has begun preparing an EIS rather than the less-robust environmental assessment ("EA") in an increasing number of pipeline cases to lessen the likelihood of FERC orders being overturned by courts. Ms. Retherford noted that this will reduce risk for project developers who rely on FERC orders when investing significant amounts of money on new projects.

Mr. Rice responded to the Sierra Club's suggestion that the capacity market can be used to support large amounts of renewables, stating that MISO and CEI South cannot rely solely on imports to maintain reliability. He noted that the basic concepts of interconnected grid operations are based on generation and load being equal in real time, which stabilizes the operational frequency of the grid at 60 hertz ("Hz"). According to Mr. Rice, if MISO and CEI South were to rely solely on imports to serve the system load during peak times, they would be subjecting customers to significant reliability and price risks. He also noted that, when operating, the CTs automatically provide dynamic reactive power to the system at a point close to the system load.

Mr. Rice addressed the CAC's claims that DR programs could be utilized in place of the CTs. He testified that DR involves risk and requires that customers voluntarily sign up for DR programs. In emergency DR programs, customers can choose not to participate during peak conditions. He stated that DR is similar to wind or solar resources in that it may not be present when most needed.

Ms. Harris also discussed the prospects for additional DR, addressing customer and industrial DR, assumptions, and modeling inputs in the market potential study and CEI South's industrial load forecast. She testified that she disagreed with Mr. Keeling's conclusion that CEI South could achieve an additional DR of 200 MW, noting that CEI South's customer makeup does not lend itself to achieving this level of DR. She stated that CEI South only has seven customers with more than 10 MW of load, and many of those customers are not in industries that readily permit idle manufacturing operations for curtailment. According to Ms. Harris, even if CEI South could achieve an additional 200 MW of DR, it would still need the two CTs, as DR programs are only issued during emergency MISO events, and the CTs more broadly support reliability.

Mr. Bradford discussed the NERC 2021 Long-Term Reliability Assessment (December 2021) (the "NERC 2021 LTRA" or "NERC Assessment"), which is included in Petitioner's Exhibit 13-R as Workpaper MAR-R3. He opined that the NERC Assessment supports CEI South's request to install fast-starting, quick-ramping generation via the CTs in order to support the growing portfolio of renewable resources and maintain reliable service. He testified that MISO's IMM, Potomac Economics, noted in the IMM Report that "MISO has correctly concluded that the availability and flexibility of its nonintermittent resources will be paramount in maintaining its ability to operate the system reliably." Petitioner's Exhibit 11-R at 4.

C. Federally Mandated CCR Compliance Projects.

i. Dry Ash Compliance Project. Mr. Games discussed the Dry Ash Compliance Project, which will involve the construction of a dry fly ash loading facility at the Archer Daniels Midland ("ADM") site in Evansville, Indiana on the Ohio River. The Dry Ash Compliance Project consists of three components: (1) a silo for accepting ash from Brown and Culley, (2) a facility to load ash onto barges for transport to Missouri for beneficial reuse, and (3) a new dry ash handling system since the previous conveyor system was converted for handling of ponded ash.

Ms. Retherford described the CCR rule, a self-implementing regulation under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"), which prohibits ash from being placed in unlined ash ponds after April 2021, unless an extension is granted. She also described the EPA's ELG rule under Section 201 of the Clean Water Act, which (1) prohibits the discharge of fly ash transport water at existing facilities, (2) prohibits the discharge of bottom ash transport water at existing facilities, and (3) sets stringent new arsenic, mercury, selenium, and nitrate/nitrite discharge limits for scrubber wastewater.

Mr. Games discussed the cost estimate for the Dry Ash Compliance Project, including $12 million in estimated capital costs and annual estimated O&M expenses of $1.35 million for 2021 through 2023 and $680,000 for 2024 and beyond. He described the EPC agreement with Penta

Engineering for this project. He also discussed the various alternatives for dry ash disposal considered by Petitioner, the site that was chosen for the project, and the estimated project schedule.

ii. Pond Compliance Project. Ms. Retherford discussed Petitioner's request for a CPCN to construct a lined CCR-compliant pond at Culley and a lined CCR-compliant pond at A.B. Brown to handle coal pile runoff, FGD wastewater, and other flows such as stormwater and landfill leachate in compliance with EPA's CCR rule.

Ms. Retherford described the recent modification to the CCR Rule ("Part A Reconsideration") requiring Petitioner to pursue the fastest technically feasible option to obtain alternative disposal capacity. She explained that the Pond Compliance Project is necessary to demonstrate to the EPA that Petitioner is complying with the CCR Part A Reconsideration. She testified there were no alternative plans considered to the Pond Compliance Project because CEI South found no other options that would achieve compliance with the "fastest technically feasible" requirement of the Part A Reconsideration.

Mr. Games discussed the cost estimate for the Pond Compliance Project, including $19 million in estimated capital costs and annual estimated O&M expenses of $350,000.

Ms. Armstrong of the OUCC testified that Petitioner's request for a CPCN for the Pond Compliance Project should be denied because CEI South has not adequately shown continuing to operate A.B. Brown Units 1 and 2 and Culley Unit 2 until October 2023 is the most reasonable, least-cost option for meeting resource needs. She stated that CEI South did not provide reasonably adequate cost estimates for the Pond Compliance Project and expressed concern that Class 5 estimates such as those presented by Petitioner could increase by 30% to 100%. She also opined that the proposed Pond Compliance Project should be denied (or recovery reduced to 50%) due to uncertainty that the EPA will grant CEI South's extension request.

Mr. Nasi, testifying on behalf of Sunrise Coal, opined that CEI South could have extended the use of coal at the A.B. Brown Units 1 and 2 if CEI South converted only the fly ash handling system to dry handling and then constructed a pond to receive only FGD and bottom ash wastewater. He asserted that this option would have allowed A.B. Brown Units 1 and 2 to continue burning coal until October 17, 2028.

Ms. Retherford opined on rebuttal that no lower cost, viable alternatives to the Pond Compliance Project exist. She stated that, if Petitioner followed the OUCC's suggestion to retire A.B. Brown Units 1 and 2 and Culley Unit 2, it would require the immediate shutdown of approximately 900 MW of CEI South's 1,200 MW of generation capacity without any replacement.

In response to Mr. Nasi's proposal, Ms. Retherford explained that the CCR Part A Reconsideration Rule provides two extension mechanisms: (1) a site-specific alternative deadline under 40 C.F.R. § 257.201(f)(1), which requires a demonstration that the development of alternative capacity is technically infeasible by April 2021; and (2) permanent cessation of a coal-fired boiler by a date certain under 40 C.F.R. § 257.103(f)(2). CEI South filed its request for extension under 40 C.F.R. § 257.201(f)(1) for the Pond Compliance Project, which requires a demonstration what is the fastest technically feasible alternative.

Due to the voluminous nature of the parties' evidence, additional evidence will be discussed as relevant below.

6. Commission Discussion and Findings on CT Project. CEI South's request for a CPCN for the CT Project is the end result of the process that began with our denial of its requested CPCN for an 850 MW CCGT, which would have cost an estimated $781 million, in Cause No. 45052. CEI South followed the guidance we issued in the 45052 Order and engaged in a thorough RFP process in which it considered many potential options for generation resources. This process ultimately resulted in CEI South's 2019 IRP and Preferred Portfolio, including the two CTs requested here. The Preferred Portfolio calls for the addition of a significant amount of renewable generation from 2022 through 2024, including approximately 300 MW of wind and up to 1,000 MW of universal solar and battery storage. *See* Petitioner's Exhibit 5, Attachment MAR-1 (2019/2020 IRP) at 53. The flexible and controllable nature of the gas CTs will support the intermittent nature of the renewable generation in the Preferred Portfolio to ensure system reliability. We believe that this step of implementing the Preferred Portfolio, moving forward on the two CTs, is the best economic decision for CEI South's customers. In addition, MISO, the operator of the electric grid in which CEI South is a participant, has indicated a system-wide need for controllable resources such as the CTs to ensure system reliability as more intermittent resources are added to the system.

Thus, for the reasons explained further below, we grant the requested CPCN for the CT Project.

A. Request for CPCN for Two CTs Under Ind. Code § 8-1-8.5-5. Ind. Code § 8-1-8.5-2 states that a public utility must obtain a CPCN from the Commission prior to constructing, purchasing, or leasing a facility for the generation of electricity. Ind. Code § 8-1-8.5-5 sets forth the criteria for approving a utility-specific generation proposal. In granting a CPCN, the Commission must make findings on the best estimate of the project's cost based on the record, whether the proposal is consistent with our statewide analysis or a utility-specific proposal, and whether public convenience and necessity require the project. The Commission must also consider the items set forth in Ind. Code § 8-1-8.5-4. We address the required findings and review each factor in Ind. Code § 8-1-8.5-4 below.

i. Best Estimate of Costs. Under Ind. Code § 8-1-8.5-5(b)(1), a CPCN may be granted only if the Commission makes a finding "as to the best estimate of construction, purchase, or lease costs based on the evidence of record[.]"

Mr. Games described CEI South's RFP for an EPC contractor and for the purchase of major equipment. He stated that CEI South, B&V, and Power Advocate reviewed and analyzed bids received in response to the RFP to ensure compatibility with the different phases of the project. Mr. Games and Ms. Carroll both discussed how Kiewit was chosen as the EPC contractor. Mr. Games described the project schedule.

As noted above, Mr. Games testified on direct that the estimated cost of the CT Project was approximately $323 million; this estimate was updated on rebuttal to approximately $334 million following execution of the EPC contract with Kiewit on November 30, 2021. According to Table WDG-4 in Mr. Games's direct testimony, explaining the breakdown of the original $323 million estimate, the EPC estimate was $188 million, including the cost for Kiewit to engineer, procure, and construct the two CTs and the direct and indirect costs of EPC overhead and profit, escalation, bonding, warranty, and builder's risk insurance. $70 million of the estimate was the owner's cost, including allowances for the owner's project management teams, the owner's engineer, support engineering and training, environmental and other permitting activities, legal fees, construction utilities, regulation and code changes, price escalation, the owner's contingency, and unresolved work scope items and terms and conditions. The cost estimate for internal labor and loadings to support the CT Project from planning through completion was $10 million. Administrative and general overhead and allowance for funds used during construction ("AFUDC") were estimated to be $35 million, and critical and long-lead-time spare parts were estimated to cost $8 million. The estimate also included $12 million in study and pre-work costs, including costs associated with CEI South's 2019/2020 IRP process (2016-2019) and preparation starting in 2019 for the filing in this Cause. The estimate did not include pipeline costs. Mr. Games opined that the estimate is consistent with Petitioner's 2019/2020 IRP.

Changes to the components of the cost estimate following the execution of the Kiewit contract are confidential and are included in Mr. Games's rebuttal testimony in confidential Table 1. Petitioner's Exhibit 2-R at 33. On rebuttal, Mr. Games testified that the adjusted base price estimate for the CT Project is $317 million, which is lower than the initial $323 million base price estimate. He identified an estimated range of the total CT Project cost between $317 and $351.4 million, with $334 million in the mid-point of this range.

In his direct testimony, Mr. Games stated that the terms of the agreement with Kiewit that remain to be resolved include indemnification, limitations of liability and consequential damages, the definition of material change, and excused delays. However, Mr. Games stated that the majority of the EPC contract price is firm. Mr. Games provided the signed agreement in Petitioner's Exhibit No. 2-R, Confidential Attachment WDG-R3.

Ms. Sommer, on behalf of the CAC, opined that "[k]ey commodity indices show concerning levels of escalation that appear to be more significant than [CEI South] has assumed in its project cost estimate." CAC's Exhibit 2 at 66. On rebuttal, Mr. Games explained that CEI South negotiated pricing adjustment mechanisms to address escalation concerns rather than accept a large firm price increase including large contingencies in order to cover a worst-case scenario. He stated that the overall base price under the executed EPC contract is lower than in the original estimate, but remains subject to price adjustments. During cross-examination, Mr. Games testified that he was reasonably confident the project would not exceed this high end of the range of costs presented in his rebuttal.

Mr. Alvarez of the OUCC opined that CEI South's estimate for the CT Project was unrealistically low. He stated that he calculated a higher capital cost of $720 per kW (compared to Mr. Games's $702 per kW estimate) for the CT Project. Mr. Alvarez evaluated the estimate using Lazard's Levelized Cost of Energy Analysis Version 14.0 (2020) ("Lazard Study") and the United States Energy Information Administration ("EIA") Annual Energy Outlook. Mr. Alvarez testified that the Lazard Study shows a range of capital cost per kW of $700 (for a 240 MW peaking unit) to $925 (for a 50 MW peaking unit). Mr. Alvarez also took issue with the fact that the CT Project cost estimate did not include the costs necessary to build the gas lateral.

On rebuttal, Mr. Games noted that CEI South's initial cost estimate was within the range of negotiated outcomes. He observed that the Lazard Study cited by Mr. Alvarez actually demonstrated that the proposed CTs are at the lower end of the range of potential capital cost per kW for peaking units, which Mr. Games attributed to the large size and efficiency of the F Class CTs proposed for the CT Project.

After reviewing the evidence of record, we find that CEI South has submitted extensive evidence supporting its cost estimate, and the other parties' evidence addressing the best cost estimate does not call CEI South's estimate into question. Thus, based on the evidence of record, we find that $334 million is the best estimate of the costs of the two CTs.

ii. <u>Consistency with Petitioner's 2019/2020 IRP</u>. Ind. Code § 8-1-8.5-5(b)(2) provides that a CPCN shall be granted only if the Commission has made a finding that either:

> (A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or
>
> (B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under [Ind. Code § 8-1-8.5-3(e)(1)] and approved under subsection (d).

Ind. Code § 8-1-8.5-3(e)(1) provides that a public utility may submit "a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility[.]" Mr. Rice sponsored Petitioner's 2019/2020 IRP as Petitioner's Exhibit 5, Attachments MAR-1 and MAR-2 (Confidential). Thus, we find that CEI South has submitted a utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

The record demonstrates that the CT Project is consistent with the Preferred Portfolio identified in Petitioner's 2019/2020 IRP. Consistent with direction from the Commission in the 45052 Order, CEI South engaged in an IRP planning process to evaluate how different portfolios performed under a range of future potential market conditions and uses and to determine the optimal mix of supply or demand resources to provide electricity to CEI South's customers. As part of its 2019/2020 IRP process, CEI South engaged in a detailed resource planning analysis and worked with several industry experts to conduct an All-Source RFP, to develop scenarios, to conduct technical modeling, and to conduct risk assessments. The record reflects that, within this process, CEI South considered 110 proposals comprising different generation resources for modeling, including battery storage, coal, combined cycle gas, load modification and demand response, solar, solar plus storage, system energy, and wind. From this analysis, 15 portfolios comprising a mix of supply- and demand-side resources were developed and modeled. CEI South also engaged and considered stakeholder input throughout the process.

The Preferred Portfolio identified through the 2019/2020 IRP called for the retirement or exit of energy provided by coal-burning units at the Brown and Culley generating stations. The Preferred Portfolio and the associated 2019/2020 IRP short term action plan which describes the early steps to pursue it, calls for CEI South to make changes to its generation portfolio in the next three years. The Preferred Portfolio mapped a shift from a generating fleet of predominantly coal-burning resources to one of intermittent renewable resources supported by gas generation to ensure reliability. One early step in implementing the Preferred Portfolio was the addition of solar generating resources approved by the Commission in Cause Nos. 45501 on October 27, 2021 and 45600 on May 4, 2022. A next step is the addition of the two new CTs requested in this Cause.

We have previously stated that, "[i]nherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions." *Northern Indiana Public Service Co., LLC*, Cause No. 45462, at 62 (May 5, 2021). The evidence demonstrates, and the Commission has previously found, that Petitioner "utilized an array of best practices, including basing model inputs on its All-Source RFP, which allowed for an informed forecast at that time." *Southern Indiana Gas & Elec. Co.*, Cause No. 45501, at 29 (Oct. 27, 2021).

Several intervenors criticized CEI South's 2019/2020 IRP process and modeling and argued in favor of alternative resources to support the Generation Transition Plan instead of the two CTs identified, as discussed further above. However, after considering the evidence of record, we find that the resource planning and selection process used by CEI South for selecting the Preferred Portfolio and Generation Transition Plan, including the two CTs requested here, is consistent with its 2019/2020 IRP, which was conducted in a manner consistent with the Commission's direction in the 45052 Order, and is therefore consistent with CEI South's utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

iii. **<u>Consistency with Commission's Energy Analysis</u>.** Ind. Code § 8-1-8.5-3(a) provides that "the commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion facilities for generation of electricity." The Commission issued its 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity ("2018 Statewide Analysis") in October 2018. *See* Petitioner's Exhibit 5, Attachment MAR-16.

The data and analysis underlying CEI South's proposal and the state of the overall electric industry have continued to develop since the 2018 Statewide Analysis. Mr. Rice noted on rebuttal that all Indiana utilities that submitted IRPs in 2021 (Duke Energy Indiana, LLC, Indiana Michigan Power Company, and Northern Indiana Public Service Company LLC) propose to retire all coal generation over the full planning period and add a large amount of solar and wind resources, supported by gas CTs, CCGTs, and some battery storage. The record in this Cause contains findings by MISO's IMM (Petitioner's Exhibit 5-R, Attachment MAR-R1; Petitioner's Exhibit 11-R, Attachment FSB-R1) and the NERC (Petitioner's Exhibit 13-R, Workpaper MAR-R3) supporting the need for flexible, controllable resources to pair with increasing levels of renewable generation to ensure reliability.

Based on the evidence of record, we find that CEI South's proposal to build the two CTs, which are flexible, controllable resources that will support the increasing use of renewables by

CEI South and other Indiana electric utilities, is consistent with the Commission's energy analysis, including the 2018 Statewide Analysis and developments since that report was issued.

iv. Public Convenience and Necessity. Under Ind. Code § 8-1-8.5-5(b)(3), before granting a CPCN, the Commission must make "a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility[.]" "The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need." *Indiana Michigan Power Co.*, Cause No. 44871, at 30 (March 26, 2018). CEI South contends the CTs are suited to the public need because they are necessary to follow CEI South's load and meet adequate reserve margins. Based on the evidence of record, we agree, as explained further below.

Our determination of public convenience and necessity under Ind. Code § 8-1-8.5-5(b)(3) is also guided by Ind. Code § 8-1-8.5-4(b), which provides that the Commission must, in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity, consider the following:

> (1) The applicant's current and potential arrangement 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.
> (2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources.

We address these considerations below.

1. Ind. Code § 8-1-8.5-4(b)(1). Mr. Rice testified that CEI South approached other electric utilities in Indiana about joint owning generation, and no partnership opportunities materialized. In addition, we note that CEI South, as a MISO participant, is already involved in the interchange of power, pooling of facilities, purchase of power, and sharing of capacity resources through MISO's market-based systems. The evidence of record shows that CEI South's participation in MISO was specifically considered in the development of the Preferred Portfolio, including the two CTs proposed here, as a result of the Commission's directive in denying the CPCN in Cause No. 45052.

Thus, the evidence of record supports the conclusion that Petitioner's current and potential options for entering arrangements with other utilities related to the interchange of power, pooling of facilities, purchase of power, and joint ownership of facilities have been evaluated, and Ind. Code § 8-1-8.5-4(b)(1) has been satisfied.

2. Ind. Code § 8-1-8.5-4(b)(2). We now analyze "[o]ther methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources."

The other parties' proposed alternatives to the CT Project are as follows:

- OUCC: Refuel A.B. Brown with natural gas;
- CAC: Use a combination of demand response, renewables, and battery storage;
- Sierra Club: Use a combination of capacity purchases, renewables, and battery storage;
- Industrial Group: Approve at most one CT, not the two proposed (based on the argument that a second CT will not be required until 2033); and
- Sunrise Coal: Continue to burn coal at A.B. Brown for several more years, assuming regulatory requirements can still be met or amended as needed.

a. **Reliability.** As it did in Cause No. 45052, the OUCC argues that Petitioner should modify Brown to burn natural gas. In response to our direction in the 45052 Order, CEI South's 2019/2020 IRP thoroughly evaluated this option, but it was not selected in the Preferred Portfolio, and the evidence of record supports a finding that it will not satisfy the need for reliability as well as the proposed CTs. Similarly, Sunrise Coal's proposal to continue burning coal at Brown for several more years does not provide the same level of flexibility in support of system reliability. In the IMM Report, MISO's IMM noted that "older gas steam and coal-fired resources . . . have long notification and start-up times. These resources provide much lower reliability value to the system because they cannot be utilized if fluctuations in intermittent resources, unexpected changes in loads, or generation outages lead to tight conditions when they happen to be offline." Petitioner's Exhibit 11-R, Attachment FSB-R1, at 120. Due to the intermittency of the renewable resources in the Preferred Portfolio, resources with quick ramp capabilities are necessary to complement the addition of such intermittent resources to the system to ensure reliability. We disagree with the OUCC and Dr. Boerger that fast start and quick ramp capabilities are not significantly relevant to these proceedings; the NERC advises otherwise. *See* Petitioner's Exhibit 13-R, Workpaper MAR-R3 (NERC 2021 LTRA), at 9-11. Refueled Brown units would not be capable of cold starts and producing energy quickly enough to satisfy the usually short-term demand periods discussed above and, thus, could not effectively follow net load.

The CAC and Sierra Club opined that the Preferred Portfolio should include more renewables and battery storage and avoid the construction of the CTs. As noted elsewhere herein, renewables such as wind and solar are dependent upon weather conditions and are, therefore, not as controllable as other sources of generation.

Regarding the use of storage, Mr. Rice explained on rebuttal that the long-duration battery storage that would be needed to replace the proposed CTs is not yet cost effective. Dr. Boerger of the OUCC testified that battery storage is not yet ready to be implemented at a utility-scale level because it is not yet economically feasible and noted technical challenges in incorporating batteries into the grid and maintaining reliability. NERC's 2021 LTRA also indicates that battery storage at the level relied upon for CAC's preferred plan will not be a viable solution until after 2030. *See*

Petitioner's Exhibit 13-R, Workpaper MAR-R3 (NERC 2021 LTRA), at 7. The three Indiana IRPs that have been completed in 2021 have preferred portfolios with storage additions constituting a modest inclusion of approximately 5% of the total capacity additions in the next six years. *See* Petitioner's Exhibit 5-R at 11 (Figure 3). We agree that, while battery storage is an emerging technology, it is currently not a viable and reliable alternative to the proposed CTs.

CAC witness Mr. Keeling opined that there is untapped DR potential in CEI South's electric service territory and suggested changes to CEI South's interruptible tariff language to access this potential. However, Ms. Harris refuted this contention, noting that Petitioner's industrial customers are much more heterogeneous than other customer segments. She stated that extrapolating results such as those presented by Mr. Keeling for industrial customers fails to account for nuances associated with this unique customer group, such as their ability and willingness to participate. In addition, the CAC's recommendation to rely on DR comes at a time when CEI South has recently lost nearly all of its industrial DR. Thus, we decline to accept a recommendation that relies on DR that does not currently exist and, in light of Ms. Harris's testimony, appears unlikely to exist in the future in Petitioner's service territory. Even so, we encourage CEI South to continue engaging its industrial customers in discussions concerning DR despite the current lack of participation to better understand barriers to such participation.

While several parties criticized Petitioner's load forecasts and used those criticisms to question the need for the CT Project, Messrs. Rice and Bradford explained that the two CTs are needed by 2025 to meet MISO's Planning Reserve Margin Requirement ("PRMR"). Anticipated load additions were shown to be far less speculative than Ms. Sommer suggested, as an executed contract with a large new customer was admitted into the record confidentially as CAC's Exhibit 9-C. We also find that Mr. Gorman's suggestion that the second CT could be delayed until as late as 2033 is not a realistic option, given the updates to the load forecast from the increased load from the new customer and loss of demand response from another.

Sierra Club witness Mr. Goggin suggested that CEI South might rely on imports to meet its reliability needs, including during extreme weather events. However, Mr. Bradford identified several significant reasons that Petitioner cannot rely on the capacity market in the long term to ensure reliability. First, he noted that Mr. Goggin extrapolated selected, low-cost MISO PRA clearing prices to conclude that market capacity should be available just as inexpensively in the future, when prices on the capacity market have, at times, been much higher than the figures utilized by Mr. Goggin in his calculations. Mr. Bradford also noted that MISO is fundamentally not a long-term capacity market, as evidenced by the fact that the auction for capacity during a given planning year running from June to May is conducted only a few months prior to the start of the planning year. Mr. Bradford also discussed MISO's position that LSEs such as Petitioner should not "free ride" on the capacity investments of other LSEs without incurring any meaningful risk. He stated that MISO has identified several consequences of "free riding," including unreasonable cost shifts, long-term harm to reliability, and decreased efficacy of the PRA as a tool to address important resource adequacy needs in MISO. He also referred to recent OMS data indicating that Zone 6 of MISO, which includes Petitioner's service territory, has the greatest potential capacity shortage across all zones.

After considering the evidence of record, we find that the CT Project is needed, consistent with the 2019/2020 IRP, and shown to be a reasonable cost-effective solution to address reliability.

b. <u>Efficiency</u>. We find that the two proposed CTs are an efficient and cost-effective solution and compare favorably among the other options proposed to follow net load. The evidence of record demonstrates that the CTs can start and ramp up or down quickly and therefore can be dispatched for short periods several times a day or for prolonged periods, whichever is necessary, to cover shortfalls. As discussed in more detail above, Mr. Games explained how the proposed F-Class CTs are much more efficient than older gas combustion units and explained why the proposed CTs are a better option as opposed to refueling A.B. Brown with natural gas, as suggested by the OUCC. Petitioner's IRP modeling concluded that repowering the Brown units with natural gas would result in higher costs from frequent energy purchases and inefficient operation.

c. <u>Economical Electric Service</u>. The Preferred Portfolio is among the lowest net present value of any of the proposals, as illustrated in Petitioner's 2019/2020 IRP. The 2019/2020 IRP results also support the conclusion that continuing to run A.B. Brown on coal or refueled with natural gas would be less affordable to customers in the near term due to high O&M and ongoing capital expenditures to keep the units running. According to Mr. Games, refueled Brown units, which cannot be started or ramped up quickly to operate only when needed to follow net load, would need to operate at an economic loss much of the time in order to be available when called on. Thus, refueled units would have a higher capacity factor than the CTs even though they theoretically are far less efficient than the CTs. A CT can run when the price of energy is high enough for the CT to be profitable and then it can quickly shut down during other less profitable hours, whereas refueled units would need to run for longer periods of time, such as 24 or 48 hours, including hours in which they operate at a loss, in order to be online during that one hour of high energy prices.

As previously noted, other parties raised issues with various aspects of CEI South's modeling. We addressed the load forecast arguments of the Industrial Group and CAC above in finding that the record supports as realistic CEI South's anticipated large customer additions and anticipated capacity shortfall by 2025 absent the two CTs. The CAC also suggested an alleged lack of transparency in Petitioner's modeling. However, the evidence reflects that CEI South offered reasonable accommodations for the CAC and other stakeholders to analyze its proprietary data, and we find that none of the parties were prejudiced by the reasonable proprietary constraints and resulting lack of a full release of the Aurora model.

Dr. Boerger and Mr. Alvarez of the OUCC criticized the cost assumptions associated with the coal-to-gas conversion as compared to the CT Project. On rebuttal, Mr. Rice addressed Dr. Boerger's analysis, noting that Dr. Boerger agreed that, even after incorporating certain changes for which he had calculated a specific dollar value effect, his calculations showed that coal-to-gas conversion of the Brown units costs customers more than the Preferred Portfolio. Regarding Dr. Boerger's concern over the discount rate used in Siemens's modeling, he acknowledged this issue would overvalue costs and benefits in the near term.

Mr. Goggin, testifying for the Sierra Club, opined that the Renewables 2030 Portfolio, which includes no CTs, had a lower cost than the Preferred Portfolio. However, CEI South noted on rebuttal that Mr. Goggin did not consider in his analysis that portfolio's performance across the full range of probabilistic futures. When doing so, the Renewables 2030 Portfolio had a higher cost and cost risk than the Preferred Portfolio.

The Industrial Group and Sierra Club suggested that the CT Project is not cost justified based on recent high gas prices. On rebuttal, Mr. Rice responded that the Preferred Portfolio performed well on multiple objectives, including cost, which considered the full range of probable gas price forecasts. The evidence also supports the reasonableness of the reference case gas price forecast in CEI South's 2019/2020 IRP.

Sunrise Coal advocated the continued operation of Brown as coal units, at least temporarily. However, the evidence of record demonstrates that CEI South cannot operate A.B. Brown as coal units beyond October 2023 without making significant expenditures for environmental compliance. The environmental regulatory requirements and timelines for completion of various actions demonstrate that continued operation of Brown without interruption is not feasible. In addition, it would require abandoning the Commission-approved settlement reached on these issues in Cause No. 45280. The evidence of record indicates that the cost to upgrade Brown to comply with CCR and ELG regulations and continue operating beyond October 2023 would be greater than the projected cost of procuring capacity in the event the CT Project were delayed beyond its anticipated in-service date. In addition, as discussed above, continuing to run A.B. Brown on coal or refueled with natural gas would be less affordable to customers in the near term due to high O&M and ongoing capital expenditures to keep the units running. We do not find that it would be prudent to attempt to keep Brown operating on coal when it is clearly not in the best interest of customers or the public to do so.

While we have indicated in previous CPCN cases that least-cost planning is an essential component of our CPCN law, we have also recognized that least-cost planning does not require selection of the absolute lowest cost alternative. *See, e.g.*, *Indianapolis Power & Light Co.*, Cause No. 44339, at 20 (May 14, 2014) (quoting *Southern Indiana Gas & Elec. Co.*, Cause No. 38738, at 5 (Oct. 25, 1989)). We have defined least-cost planning as a planning approach that will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined. We also consider the risk created by future uncertainty. Ind. Code ch. 8-1-8.5 does not require a utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment on how best to meet its obligation to serve. If a 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 Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting options to implement which minimize the cost of providing such services. *Id.*

We are concerned about the risks of further delay that would be caused by rejecting Petitioner's selection in favor of further study (beyond that already performed as part of the 2019/2020 IRP process) of the options proposed by the other parties. None of the options being proposed by the OUCC, CAC, Sierra Club, or Sunrise Coal would address the concerns raised by the NERC and MISO to encourage the development of flexible, controllable resources, such as the CTs proposed here, to complement the transition to intermittent, renewable resources. In the event of a denial, Petitioner would still need to secure the capacity offered by the CTs. In addition, other variables, such as the cost of iron and steel, could result in increased cost if the requested CPCN is denied. For example, CAC's Exhibit CX-1 shows the significant growth in the Producer Price Index for Metal and Metal Products: Iron and Steel. As discussed above, Mr. Games testified that Petitioner's proposal is protected against this inflation as a result of the EPC contract that has already been negotiated. None of the other options being urged by the various stakeholders would be similarly protected by contract. In light of the evidence of record, we find that CEI South has exercised its reasonable judgment in selecting an option that both minimizes the risks of future cost uncertainty and will allow it to meet its obligation to provide reliable service to its customers.

3. Conclusion. Petitioner conducted an All-Source RFP to meet its capacity needs, and the RFP responses enabled CEI South to consider a variety of alternatives, described above. Given the foregoing evidence, the Commission finds that Petitioner has satisfied the requirement under Ind. Code § 8-1-8.5-4 that it consider alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources. Ultimately, CEI South's 2019/2020 IRP has shown that the proposed construction of two new CTs at the A.B. Brown site is a reasonable, least-cost resource to support Petitioner's Generation Transition Plan and meet customers' needs for electricity. The CTs are capable of cycling reliably in response to the MISO market and will partially replace the retiring coal units with more efficient and controllable load-following capacity.

Therefore, based on the evidence of record, the Commission finds that Petitioner has shown a need for the proposed CT Project and that public convenience and necessity require or will require Petitioner's construction of the CT Project.

v. Competitive Procurement. Ind. Code § 8-1-8.5-5(b)(5) requires us to make certain findings under Ind. Code § 8-1-8.5-5(e) if the proposed facility has a generating capacity of more than 80 MW, as is the case here:

> Before granting a certificate to the applicant, the commission:
> (1) must, in addition to the findings required under subsection (b), find that:
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and
> (2) shall also consider the following factors:
> (A) Reliability.
> (B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.
>
> The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

Petitioner conducted two RFPs for EPC bids and major equipment purchases and utilized Power Advocate to administer the RFP process. These RFPs informed Petitioner's best estimate of the costs for the CT Project. Accordingly, we find Ind. Code § 8-1-8.5-5(e)(1)(A) has been satisfied and that the cost estimates of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts. The EPC contractor was selected as a result of this RFP process, and the executed EPC contract was admitted into the record on a confidential basis. Petitioner's Exhibit 2-R, Attachment WDG-R4 (Confidential). The contract for construction of the CT Project was the result of competitive bidding in satisfaction of Ind. Code § 8-1-8.5-5(e)(1)(B).

Regarding Ind. Code § 8-1-8.5-5(e)(2), we have found herein, based on the evidence of record, that the proposed CT Project is reliable. The record has also established that Petitioner engaged in an All-Source RFP process to inform its Generation Transition Plan. Thus, we have considered reliability and solicitation by CEI South of competitive bids to obtain purchase power capacity and energy from alternative suppliers, and we find that the requirements of Ind. Code § 8-1-8.5-5(e) are satisfied.

vi. **<u>Gas Pipeline Lateral</u>.** Intervenors and the OUCC raised concerns about the gas lateral pipeline to be constructed by Texas Gas Transmission, LLC ("TGT") pursuant to the Precedent Agreement between CEI South and TGT. We recognize that the pipeline and the ability to secure adequate gas on that pipeline are both critical to CEI South's ability to operate the CTs as proposed.

However, we note that ruling on the public convenience and necessity of natural gas-fired generation before the establishment of the gas supply to serve it is not unprecedented. In Cause No. 44339, in which Indianapolis Power & Light ("IPL") sought a CPCN for its Eagle Valley CCGT, IPL initially pursued constructing the natural gas lateral itself, but eventually changed its plans and sought bids from several companies to build the lateral. In other words, we issued the CPCN without evidence that IPL had even entered a contract for the gas supply lateral. *See Indianapolis Power & Light Co.*, Cause No. 44339, at 23-24 (May 14, 2014).

However, it is possible that the assured cost recovery provided by the CPCN statute could enable CEI South to begin incurring significant costs to construct the CTs before FERC approval of the pipeline. The contracts that CEI South has with TGT for the pipeline and Kiewit for EPC matters are not dependent on one another; the timing and conditions precedent within them could allow for the progression of one without the other. If the FERC does not approve the pipeline, Petitioner will have incurred CT construction costs for a facility that cannot be built and operated in its proposed location.

The EPC contract includes a feature that allows for different notice to proceed ("NTP") issuance dates and associated deliverables, which balance the price and time to build risk between Kiewit and CEI South as the NTP date is delayed. After the Final Anticipated NTP issuance date (which is confidential), the contractual arrangements between Petitioner and Kiewit will be subject to further negotiation. Given that the pipeline contract with TGT cannot proceed until FERC approves the pipeline, and the unknown of when and even if that will occur is outside this Commission's control, we find that Petitioner shall utilize the EPC contract's NTP feature to minimize risk to the greatest extent possible in order to coordinate the construction of the CTs with FERC approval of the pipeline. If applied reasonably, this will limit potential sunk costs incurred before FERC pipeline approval with the delayed in-service date of the CTs. For these reasons, our approval of the requested CPCN for the CT Project is conditioned on the requirement that Petitioner issue the NTP under the EPC contract with Kiewit no earlier than the Final Anticipated

NTP issue date or the date of FERC approval of the TGT pipeline, whichever is earliest. Under this condition, the CT construction might still proceed before FERC approval of the pipeline, but potential CT construction costs will be limited to the greatest extent possible, should the pipeline not be authorized by the FERC.

Should Petitioner reach the conclusion that it should not move forward with the NTP because of emergent concerns not considered herein, it shall submit a compliance filing in this docket describing its decision no later than 15 days before the Final Anticipated NTP date. In addition, Mr. Greeley, in response to a question from the bench during the hearing, noted the possibility of Petitioner considering some form of "limited" NTP, if needed. Should such a limited NTP be issued, Petitioner is directed to submit a compliance filing in this docket within 15 days of the issuance of a limited NTP.

vii. <u>Conclusion on CPCN for CT Project</u>. Ind. Code § 8-1-8.5-5(d) requires us to "consider and approve, in whole or in part, or disapprove a utility specific proposal . . . jointly with an application for a certificate under this chapter[, but] solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity."

In the 45052 Order, the Commission discussed in detail the reasons the CPCN was denied in that case and how CEI South could improve its planning prior to future CPCN requests, including by incorporating flexibility and removing restrictions that might screen out multiple less-expensive alternatives. In this case, CEI South lessened the restrictions on its RFP, considered refueling and other potential options, and considered the diversity of its generation fleet. The 2019/2020 IRP process resulted in a Preferred Portfolio with a mix of generation resources that have flexibility for changing circumstances. In Cause No. 45052, CEI South sought approval of an 850 MW CCGT generation facility, as opposed to the two CTs for which a CPCN is sought in this case, which have a combined generation capacity of 460 MW. It appears that CEI South has considered and implemented the guidance of the 45052 Order in its 2019/2020 IRP and the requests made in this Cause.

Based upon the evidence of record, the Commission finds that CEI South has met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity require construction of the CT Project. Therefore, we grant CEI South's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

B. <u>Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a)</u>. Ind. Code § 8-1-8.5-6(a) addresses the Commission's review of facilities under construction as follows:

> In addition to the review of the continuing need for the facility under construction . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.

CEI South requested that the Commission conduct ongoing review of the CT Project, proposing to submit construction progress reports, any revisions to the cost estimates, and other information regarding the CT Project to the Commission on an annual basis during construction.

We find that CEI South shall report, at least semi-annually, to the Commission a summary of the information related to the CT Project, including safety, scope, schedule, and owner's cost contingency, as well as the: (1) manufacturer, model number, and operational characteristics of the turbine generator; (2) anticipated total annual MW-hour ("MWh") output for the CT Project; (3) revisions to the cost estimate; and (4) update on the natural gas transportation and lateral pipeline.

The initial CT Project report shall be filed on or before December 30, 2022 as a compliance filing in this Cause. The final project report shall contain the following information: (1) the actual total cost of construction; (2) the total MW output for the facility; and (3) the actual in-service (commercial operation) date for the facility.

In addition, due to recent global supply chain issues that could potentially limit the availability of components necessary to build the CTs, Petitioner shall provide an update on any supply-chain-related challenges and/or delays on December 30, 2022 and continuing on a semi-annual basis thereafter until both CTs are placed into commercial operation. Such updates shall be filed under this Cause.

C. Accounting and Ratemaking for CT Project. CEI South is not seeking to adjust customers' rates to recover the costs of the CT Project before its next base rate case. CEI South requests accounting authority, starting with the date the CT Project is placed in service, for the deferral of depreciation and financing costs, including post in-service carrying costs ("PISCC"), related to the CT Project investment until such time as those costs and the CT Project's investment is reflected in CEI South's retail electric rates. The estimated construction costs for the CT Project are approximately $334 million compared to an estimated electric rate base as of December 31, 2020 of $1.5 billion.

Ms. Gostenhofer testified that CEI South proposed applying its approved depreciation rate for combustion turbines to the CT Project, resulting in a 3.44% annual depreciation rate, including the cost of removal. She stated that CEI South may evaluate adjustments to this depreciation rate in its next base rate case as part of a depreciation study. No party presented any evidence specifically opposing the application of this depreciation rate.

According to Ms. Gostenhofer, an estimated $11.1 million of annual depreciation expense and $20.7 million of incremental financing costs will be unrecoverable through rates due to the timing of recovery of the financing costs associated with the plant being placed in service. She also stated that, in addition to the new capital investments made in the CT Project, CEI South is making other large investments to comply with environmental regulations. She opined that the proposed accounting treatment helps mitigate the negative impact on income the CT Project would have between the period it is placed in service and until it is recovered in rates. She said that deferral and recovery of PISCC and depreciation expense helps Petitioner manage its increased carrying costs during a period of increased investments.

Industrial Group witness Mr. Gorman opined that recovery of the deferred costs in CEI South's next rate case should be contingent on CEI South proving that: (1) the revenues CEI South collected in existing rates during the deferral period were not adequate for it to recover its cost of service during the deferral period; and (2) CEI South made every reasonable effort to coordinate the timing of its rate case with the in-service date of the CT Project. He stated that, because CEI South can file a rate case utilizing a future test year, CEI South should be permitted to defer cost recovery for no more than six months.

Petitioner's request for deferral of PISCC and depreciation is not novel. We have frequently heard and granted such requests, and the test we have consistently applied is whether the cessation of AFUDC and commencement of depreciation will cause severe earnings erosion. *See, e.g., Indianapolis Power & Light Co.,* Cause No. 44339 (May 14, 2014). The evidence of record demonstrates that CEI South will suffer severe earnings erosion during the time between the date the two CTs are placed in service and CEI South's next rate case order authorizing recovery of a return on the CTs and depreciation expense. During this interim period, CEI South will also not be recovering carrying costs of the construction project. CEI South's requested accounting treatment would allow it to offset the erosion to monthly pre-tax earnings by approximately $2.65 million due to the deferral of the depreciation expense and continuation of the $20.7 million of financing costs incurred by the utility and previously recovered through AFUDC. The additional conditions Mr. Gorman seeks to impose on this accounting relief are inconsistent with the earnings erosion standard.

Therefore, we authorize CEI South to: (1) apply the 3.44% depreciation rate discussed above; (2) accrue PISCC, at CEI South's currently approved weighted average cost of capital ("WACC"), on the two CTs beginning with the month after the in-service date of each individual CT Project asset until the date CEI South's base rates include a return on the CT Project; (3) record the depreciation expense on each individual CT Project asset beginning with the month after its in-service date; (4) record deferred PISCC and depreciation in a regulatory asset in Account 182.3, Other Regulatory Assets, through the date CEI South's base rates include a return on the CT Project and recovery of the depreciation expense; (5) amortize the regulatory asset as a recoverable expense for ratemaking purposes over the estimated life of the CTs commencing on the date of the order authorizing recovery in CEI South's rates of a return on the CTs and depreciation expense; and (6) include the unamortized portion of the regulatory asset in CEI South's rate base upon which it is permitted to earn a return.[1]

Petitioner also sought authority to capitalize allocable costs of preparing the IRP and preparing this case to the costs of the CT Project and to amortize these costs over the life of the asset.[2] Mr. Lantrip of the OUCC recommended that the Commission follow the 45052 Order and reject CEI South's proposed treatment of the CT Project's planning costs, including the $5 million in IRP planning costs. He testified that IRP planning costs are a non-recurring cost of doing business, and there is no Commission precedent allowing for the separate recovery of IRP planning costs. Similarly, Mr. Gorman testified for the Industrial Group that CEI South has not proven that its IRP costs are properly capitalized to the CT Project, as opposed to expensing those costs

[1] We have previously held that WACC is the appropriate rate for post-in-service carrying charges. *See, e.g., Indianapolis Power & Light Co.*, Cause No. 44339, at 35 (May 14, 2014) (citing orders).

[2] Petitioner also sought in the alternative to defer such costs as a regulatory asset to be recovered through rates in the event the CPCN for the CT Project is denied. Because we have issued the CPCN, this part of the request is moot.

currently as ongoing system planning costs. He stated that CEI South has offered no proof that the IRP costs could not be recovered via rate revenue in the year the cost was incurred.

On rebuttal, Ms. Gostenhofer testified that all the planning costs, including the $5 million in IRP planning costs identified by Mr. Lantrip, to be included in the CT Project are incremental expenditures specifically related to the CT Project and must be incurred as part of the construction of the CTs. She stated these costs initially meet the criteria to be deferred on the balance sheet, in accordance with FERC 183 or FERC 107, as applicable, and are therefore not considered operating costs of CEI South in accordance with the FERC Uniform System of Accounts ("USOA"). She explained that CEI South's IRP generation asset planning pool costs that are the subject of Petitioner's deferral request do not include any costs stemming from CEI South's request for a CPCN for the CCGT that was denied in Cause No. 45052. She stated that, after the 45052 Order was issued in April 2019, CEI South reviewed all planning costs deferred for future recovery in the generation asset planning pool to identify any costs that related to activities supporting a large-scale gas generation asset, such as the then-proposed and ultimately denied CCGT, that would not be applicable to future assets developed under the IRP that would need to be either charged to a regulatory asset or to operating expense. She stated that the remaining costs in the generation asset planning pool had been in support of smaller-scale options. Thus, she opined that it was reasonable to expect the studies and activities for those costs to become used and useful in support of the construction of assets resulting from the IRP, such as the CT Project at issue in this Cause.

After considering the evidence of record, we find that Petitioner's best estimate of costs includes an estimate of $12 million in planning costs. About $5 million of that total consists of Generation Asset Planning Pool costs that relate to Petitioner's request for a CPCN for the CT Project. This consists of costs as described by Ms. Gostenhofer related to the 2016 and 2019 IRPs, excluding costs related to a large-scale generating asset such as a CCGT that was denied in Cause No. 45052. We have adopted the FERC USOA by rule. 170 IAC 4-2-1.1(a). FERC 183B provides, "This account shall also include costs of studies and analyses mandated by regulatory bodies related to plant in service. If construction results from such studies, this account shall be credited and the appropriate utility plant account charged with an equitable portion of such study costs directly attributable to new construction." The costs at issue in Petitioner's Generation Asset Planning Pool fit this definition, and the evidence of record indicates that Petitioner has allocated an equitable portion to the CT Project. Thus, we find that Petitioner's proposal to include these costs in the capital costs of the CT Project is consistent with the FERC USOA and is appropriate.

D. <u>Other Gas Pipeline Lateral Issues</u>. As mentioned previously, several of the parties' witnesses expressed concern regarding various issues related to the gas pipeline lateral. CAC witness Ms. Sommer opined that TGT's proposed pipeline is oversized and that CEI South is acquiring gas transmission capacity that greatly exceeds that which is needed to supply the proposed CTs. She opined that a smaller pipeline could serve the CTs at a lower cost.

Industrial Group witness Mr. Gorman testified that he believed CEI South did not make every reasonable effort to reduce the $27.3 million annual cost burden on ratepayers. He also opined that CEI South has not demonstrated that it has structured the arrangement with TGT to facilitate sales of unused capacity on the lateral to third parties. He stated that CEI South has not established that the proposed location of the lateral pipeline is the most prudent and least cost option. Mr. Gorman also took issue with the binding nature of the agreement and the timing of the construction of the pipeline.

Sunrise Coal witness Ms. Medine noted the lack of certainty that the pipeline will be approved by the FERC, noting the EIS requirement imposed by FERC. Mr. Nasi, also testifying on behalf of Sunrise Coal, opined that it would not be prudent to proceed with the CT project prior to resolution of the FERC matter.

In response to criticism of the pipeline's location, Mr. Hoover testified on rebuttal that TGT decided that, to obtain the most effective balance of pipeline pressure, reliability, and capacity, the optimal location for the lateral interconnection to the TGT mainline system was near Robards, Kentucky. While some of TGT's interstate pipelines extend into Indiana, Mr. Hoover stated that necessary improvements to those pipelines for capacity and pressure requirements, additional compression to meet the pressure requirements, and more congested routes make them less economically feasible as the interconnection location for the lateral. He noted that the existing Dogtown lateral is of insufficient size and operating pressure to serve the CTs, and the other TGT interstate pipelines are routed north through the east side of Vanderburgh County, making them farther from A.B. Brown than the Robards, Kentucky location. Using those pipelines would also require a lateral to be installed through much more populated and congested areas.

Mr. Hoover also responded to Ms. Sommer's assertion that TGT's proposed pipeline is oversized, stating that a 20-inch lateral is required to provide the required gas flow rate and pressure to the combustion turbines. He said that the 16-inch lateral size does not have adequate margin, and installation of an undersized lateral cannot be easily or cheaply remediated. He testified that TGT informed CEI South that the price for demand on the lateral would be the same for all of the capacity or a portion of it; given this, CEI South contracted for the full pipeline capacity.

Based on our review of the evidence of record, we are satisfied with CEI South's decision to secure transportation capacity pursuant to the Precedent Agreement with TGT rather than pursuing some combination of alternatives, including use of the Dogtown lateral, an alternative TGT route, or on-system storage. The evidence of record supports a finding that the Dogtown lateral is incapable of supporting the CT demand or pressure requirements. A different route would have required additional improvements to TGT's system to meet capacity and pressure requirements and would have involved a more congested route for the lateral.

The evidence is unrefuted that Petitioner will require service from a lateral pipeline to serve the two CTs. Further, we find that the evidence supports that the proposed TGT pipeline will provide the required service to the two CTs. Accordingly, it is appropriate that Petitioner should receive reasonable cost recovery for the expenses it incurs for the service it receives from the TGT pipeline.[3] However, the specific amount and the means of that cost recovery will be subject to further proceedings as discussed below.

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[3] We have previously allowed a utility to recover fuel costs associated with a CCGT in its FAC mechanism. In Cause No. 44339, IPL proposed to recover fuel costs associated with its Eagle Valley CCGT and Harding Street Refueling projects through its FAC, which has now occurred. *Indianapolis Power & Light Co.*, Cause No. 38703 FAC 127, at 3 (June 3, 2020) ("[T]he cost of gas generation contains the delivered cost of natural gas including firm transportation.").

The Industrial Group also disputed CEI South's proposal to recover the costs associated with the gas lateral through its FAC. Mr. Gorman testified that fixed pipeline capacity costs and the gas lateral costs should not be recovered through CEI South's FAC because customers should pay for the CTs in line with the benefits provided, which are related to system capacity and not energy. He proposed that the TGT fixed costs be allocated to CEI South customers based on their contribution to system capacity needs. He stated that the fixed costs of the gas delivery pipeline, while not varying with electricity generated from the CTs, are critical capital costs needed so the CTs can be available to support system reliability when called upon. Mr. Gorman opined that allocation of the CT Project capacity costs in this way, including the TGT fixed gas lateral costs, produce price signals that would encourage customers to make efficient consumption decisions.

Once FERC decides whether TGT is permitted to build the pipeline, the question of how the costs of that gas service should be recovered from CEI South's customers can be addressed by the Commission. Mr. Rice noted on rebuttal and during the hearing that a subdocket could be opened to investigate the appropriate allocation for cost recovery purposes of the cost of the gas lateral throughout the term of the Precedent Agreement. We agree and find that such a subdocket shall be opened within 30 days of FERC approval of the pipeline. Petitioner shall notify the Commission within five business days of the FERC's final order regarding the pipeline lateral and file a copy of that order under this Cause. To the extent that reasonable pipeline costs allocated to Petitioner's customers are not ultimately recovered through Petitioner's fuel adjustment clause ("FAC") mechanism, we grant CEI South's alternative request for deferral of such costs until such costs are recovered through base rates following a general rate case.

7. Commission Discussion and Findings on CCR Compliance Projects.

A. CPCN Request for CCR Compliance Projects. CEI South also seeks CPCNs for the CCR Compliance Projects (the Dry Ash Compliance Project and the Pond Compliance Project), both of which are "federally mandated" projects under Ind. Code ch. 8-1-8.4.

When considering a petition under Ind. Code § 8-1-8.4-7, the Commission must grant the CPCN if it:

> (1) made a finding that public convenience and necessity will be served by the proposed compliance project;
> (2) approved the projected federally mandated costs associated with the proposed compliance project; and
> (3) made a finding on each of the factors set forth in [Ind. Code § 8-1-8.4-6(b)].

Ind. Code § 8-1-8.4-7(b).

The factors we must consider in Ind. Code § 8-1-8.4-6(b) are as follows:

> (1) The following, which must be set forth in the energy utility's application for the certificate sought, in accordance with section 7(a) of this chapter:
> (A) A description of the federally mandated requirements, including any consent decrees related to the federally mandated requirements, that the

energy utility seeks to comply with through the proposed compliance project.

(B) A description of the projected federally mandated costs associated with the proposed compliance project, including costs that are allocated to the energy utility:

(i) in connection with regional transmission expansion planning and construction; or

(ii) under a Federal Energy Regulatory Commission approved tariff, rate schedule, or agreement.

(C) A description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements described by the energy utility under clause (A).

(D) Alternative plans that demonstrate that the proposed compliance project is reasonable and necessary.

(E) Information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension.

(2) Any other factors the commission considers relevant.

i. Federally Mandated Requirements (Ind. Code § 8-1-8.4-6(b)(1)(A)). 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[,]" including, but not limited to, "[t]he federal Water Pollution Control Act (33 U.S.C. 1251 et seq.)" and "[a]ny 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."

Petitioner has proposed to undertake the CCR Compliance Projects to comply with the EPA's CCR and ELG rules. No party has disputed that these rules constitute federally mandated requirements under Ind. Code § 8-1-8.4-5. Thus, we find that Petitioner has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(A).

ii. Projected Costs (Ind. Code § 8-1-8.4-6(b)(1)(B)). 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. Mr. Games testified about the costs of the CCR Compliance Projects.

No party disputed Petitioner's cost estimates for the Dry Ash Compliance Project. However, Ms. Armstrong of the OUCC opined that CEI South did not provide reasonably adequate cost estimates for the Pond Compliance Project, given that the estimates were Class 5 and could increase by 30% to 100%. However, we note that, under Ind. Code § 8-1-8.4-7(c)(3), "[a]ctual 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." Ind. Code § 8-1-8.4-7(c)(3). If Petitioner's actual costs prove to be 30% to 100% more than its estimates, CEI South will be required to justify them.

Thus, based on the evidence of record, we find that CEI South has identified federally mandated costs (as defined by Ind. Code § 8-1-8.4-4) for the CCR Compliance Projects and reasonably described those costs. The total capital costs for the CCR Compliance Projects are estimated at $31 million ($12 million for the Dry Ash Compliance Project and $19 million for the Pond Compliance Project). Annual O&M costs for the Dry Ash Compliance Pond are estimated at $1.35 million through 2023 and $0.68 million for 2024 and beyond; annual O&M costs for the Pond Compliance Project are estimated at $350,000.

. We find that these estimated costs are reasonable and are therefore approved.

iii. <u>How the Proposed Projects Allow Compliance with Federally Mandated Requirements (Ind. Code § 8-1-8.4-6(b)(1)(C))</u>. Ms. Retherford testified that the CCR Compliance Projects are required to comply with the CCR and ELG rules, which prohibit the continued wet sluicing of fly ash transport water for disposal in an unlined ash pond.

1. <u>Dry Ash Compliance Project</u>. Petitioner presented evidence that the Dry Ash Compliance Project will allow it to remain in compliance with the CCR and ELG rules and continue to load dry fly ash for transport and shipment for beneficial reuse, as dry fly ash can no longer be disposed of in the ash ponds. Ms. Retherford testified that dry fly ash cannot be loaded at the Ohio River loading facility located at A.B. Brown, as that system has been converted to load-ponded ash under the CCR closure plan. With the conversion of the loading facility at A.B. Brown, Petitioner was required to find an alternative loading facility for dry fly ash in order to remain in compliance with the CCR and ELG rules' prohibition against disposal of dry fly ash in an unlined ash pond. The Dry Ash Compliance Project will ensure that Petitioner can continue to burn coal and beneficially reuse fly ash through the retirement of the coal-fired units at A.B. Brown in October 2023 and the continued operation of F.B. Culley Generating Station's Units 2 and 3 through their retirement dates. The Dry Ash Compliance Project also supports the Part A Reconsideration extension requests under the CCR rule for both Brown and Culley. The Dry Ash Compliance Project also directly provides alternative disposal capacity for dry fly ash and supports the extension request for the remainder of the CCR waste streams. No party disputed that the Dry Ash Compliance Project will allow CEI South to comply with the CCR and ELG rules, and we therefore find that Ind. Code § 8-1-8.4-6(b)(1)(C) is satisfied for this project.

2. <u>Pond Compliance Project</u>. The Pond Compliance Project will consist of two lined CCR-compliant ponds, one each at Culley and Brown. Ms. Retherford testified that construction of the ponds will serve to provide CCR-compliant wastewater containment between closure of the east ash pond and completion of the ELG wastewater treatment upgrades approved in Cause No. 45052. Given the small quantity of bottom ash generated by Culley Unit 2, one of the new lined CCR-compliant ponds provides Petitioner with the opportunity to use the new lined pond for short-term bottom ash disposal if Petitioner chooses to continue to operate Culley Unit 2 through December 2025 under the ELG Reconsideration rule. She stated that construction of the lined CCR-compliant ponds will serve to provide CCR-compliant wastewater containment for landfill runoff leachate, storm water, coal pile runoff until decommissioning is complete, wastewater treatment, and continued mercury treatment of ash pond water during dewatering and ash pond closure activities. However, the new CCR-compliant ponds will not have sufficient size to permit effective hydraulic capacity and settling capacity for the additional ash flows currently entering the ash pond. The new lined CCR pond at Brown will serve as the stormwater pond for the CT Project.

The only disputed issue regarding the Pond Compliance Project concerns the deadline for achieving compliance. The CCR rule was finalized in 2015, and it contains three tests that require the closure of an ash pond if the tests are not satisfied. At the time of promulgation, the CCR rule required a pond failing the tests to cease receipt of materials by April 2017 and for closure be initiated within 30 days. All three of CEI South's ponds triggered closure requirements.[4] Under the original CCR rule, a utility could take five one-year self-implementing extensions of the final cessation deadline if there was no alternative capacity available. In July 2018, the EPA revised the final cessation deadline for cessation of receipt of materials to October 2020. In August 2020, the final cessation deadline was again revised to April 11, 2021, in what is known as the Part A Reconsideration Rule. The Part A Reconsideration Rule also eliminated the self-implementing annual extension option and replaced it with a new mechanism, which requires a utility to file a formal extension request with the EPA that would extend the cessation deadline to no later than October 15, 2023. In order to qualify for an extension, the utility must demonstrate it has no alternative capacity and that it is actively pursuing alternative disposal capacity in the technically feasible timeframe for each individual CCR waste stream. The evidence reflects that CEI South submitted a timely application for an extension under the Part A Reconsideration Rule, but the EPA has not yet ruled on this request. The Pond Compliance Project is the alternative disposal capacity that CEI South has been "actively pursuing" in accordance with the requirements for pond extension under the Part A Reconsideration.

Although the OUCC acknowledged that CEI South filed timely requests for extension, Ms. Armstrong argued that the proposed Pond Compliance Project should be denied (or recovery reduced to 50%) because of uncertainty regarding whether the EPA will grant CEI South's extension request. Ms. Retherford responded that the EPA has recently indicated that it may not finalize completeness reviews until late spring 2022, and she opined that CEI South has no viable alternative but to continue to implement the CCR compliance strategies as proposed in its extension packages.

No party disputed Petitioner's position that the Pond Compliance Project will allow compliance with the CCR Rule. We need not address at this time any consequences if EPA ultimately denies Petitioner's request for an extension of time. We find that the Pond Compliance Project will allow CEI South to comply with federally mandated requirements and that Ind. Code § 8-1-8.4-6(b)(1)(C) is satisfied for this project.

iv. <u>Alternative Plans (Ind. Code § 8-1-8.4-6(b)(1)(D))</u>. Mr. Games discussed potential alternative options to the Dry Ash Compliance Project, which were summarized in Table WDG-8 in his testimony. Options considered included the modification of

[4] The west pond at Culley has already been closed. CEI South has requested an extension from the EPA for the east pond at Culley while it completes the ELG upgrades for Culley Unit 3 that were authorized in Cause No. 45052. The Brown ash pond is being excavated for beneficial reuse as authorized in Cause No. 45280.

an existing landfill or building a new landfill; depositing ash in a coal mine; utilizing a municipal landfill; using separate ponded and dry loading systems at Brown; using a common loading system at Brown; constructing a loading system at Culley; and pugging or adding and mixing water to dry ash before shipping with ponded ash. After considering these options, CEI South identified the construction of a new dry fly ash loading facility at the ADM site as the best viable solution.

Ms. Retherford testified that no reasonable alternatives exist to the proposed Pond Compliance Project because CEI South is required to implement the alternative disposal capacity as fast as technically feasible. She stated that CEI South investigated five other options, none of which would achieve compliance because they cannot be completed more quickly than the ponds. She provided evidence of the extensive review of alternatives and links to thousands of pages of information submitted to the EPA regarding alternatives.

Ms. Armstrong of the OUCC argued that the Pond Compliance Project should be denied because CEI South has not adequately demonstrated that continuing to operate Brown Units 1 and 2 and Culley Unit 2 until October 2023 is the most reasonable, least-cost option for meeting resource needs. On rebuttal, Ms. Retherford responded that this alternative would require more immediate retirement of Brown Units 1 and 2 and Culley Unit 2, as suggested by Ms. Armstrong, but also the immediate shut down of Culley Unit 3 which must continue to use the Culley East ash pond until the completion of the wastewater treatment upgrades approved in Cause No. 45052 that are not scheduled to be completed until March 2023. Ms. Retherford stated that the OUCC's alternative option would require the immediate shutdown of approximately 900 MW of CEI South's 1,200 MW of generation capability with no approved replacement capacity. She opined that the OUCC's position that CEI South's proposed CCR Compliance Ponds should not be approved because CEI South did not provide a comparison between the costs associated with the immediate replacement of 900 MW of capacity and the costs to construct two small extension ponds is not reasonable. She stated that the OUCC's recommended approach would jeopardize CEI South's ability to meet its obligation to provide safe and reliable service to its customers.

Sunrise Coal witness Mr. Nasi proposed that Petitioner could extend the use of coal at the Brown Units if CEI South converted only the fly ash handling system to dry handling and then constructed a pond to receive only FGD and bottom ash. In his view, this option would allow Brown to continue burning coal until October 17, 2028. On rebuttal, Ms. Retherford opined that this is not a feasible option. The CCR Part A Reconsideration Rule provides two extension mechanisms: (1) a site-specific alternative deadline under 40 C.F.R. § 257.201(f)(1), which requires a demonstration that the development of alternative capacity is technically infeasible by April 2021; and (2) permanent cessation of a coal-fired boiler by a date certain under 40 C.F.R. § 257.103(f)(2). 40 C.F.R. § 257.201(f)(1), which applies to the Pond Compliance Project, requires a demonstration of what is the fastest technically feasible alternative. Mr. Nasi did not address how his proposal could be achieved more quickly than the Pond Compliance Project.

Based on the evidence of record, we find that CEI South considered alternative plans for compliance with the ELG and CCR rules and selected the most reasonable options in the CCR Compliance Projects. The evidence demonstrates that the CCR Compliance Projects are reasonable and necessary.

v. <u>Extension of Useful Life of Existing Facility (Ind. Code § 8-1-8.4-6(b)(1)(E))</u>. No party disputes that the issuance of CPCNs for the CCR Compliance Projects will extend the useful life of coal-burning units at Brown and Culley. Based on the evidence presented, we find that CEI South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

vi. <u>Conclusion</u>. As discussed above, we find that Petitioner has satisfied all five subsections of Ind. Code § 8-1-8.4-6(b)(1), and we find that there are no additional factors that need to be considered under Ind. Code § 8-1-8.4-6(b)(2). We find that the public convenience and necessity will be served by the CCR Compliance Projects, approve the projected federally mandated costs associated with the CCR Compliance Projects, and issue the requested CPCNs for the CCR Compliance Projects.

The only remaining issue that has been raised is Ms. Armstrong's request that we only allow CEI South to recover 50% of the federally mandated costs. However, having made the required findings, the statute directs that we "shall . . . grant a certificate." Ind. Code § 8-1-8.4-7(b). A certificate having been granted, the statute directs that 80% of the approved costs shall be recovered through a periodic rate adjustment, with 20% of approved costs deferred. There is no authority under any relevant statute to deny recovery as Ms. Armstrong has proposed, absent any evidence that the federally mandated costs could have been reduced by 50% through some alternative course of action.

B. <u>Accounting and Ratemaking for Federally Mandated CCR Projects</u>.

i. <u>Recovery of Federally Mandated Costs (Ind. Code § 8-1-8.4-7)</u>. 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.

CEI South requests authority to include the costs of the CCR Compliance Projects in its annual environmental cost adjustment ("ECA") rate adjustment mechanism pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs, with the remaining 20% of the revenue requirement to be deferred and recovered by CEI South as part of its next general base rate case. Ind. Code § 8-1-8.4-7 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 provides that such costs may include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Ms. Gostenhofer described how the eligible costs associated with the CCR Compliance Projects will be incorporated into Petitioner's annual ECA mechanism. She testified that CEI South will prepare in each annual filing a revenue requirement calculation which will accumulate all eligible costs incurred through December 31 of the previous calendar year. Those eligible costs will include return on new capital investments, calculated as the new capital investments in plant related to the CCR Compliance Projects, multiplied by the applicable rate of return for the ECA, plus incremental expenses, which will include depreciation, O&M, property tax expenses, and other costs associated with the CCR Compliance Projects. The revenue requirement on the CCR Compliance Projects will represent the basis for the recovery of 80% of the eligible revenue requirement requested in each annual ECA filing and deferral of 20% of the eligible revenue requirement for future recovery.

According to Ms. Gostenhofer, CEI South proposes to include in the revenue requirement for new capital investments the gross plant specific to the new capital investments for the CCR Compliance Projects, both in service and construction work in progress ("CWIP"). The project costs for these new capital investments will include various direct and indirect costs and financing costs incurred during construction, commonly referred to as AFUDC. She also described CEI South's proposal to defer and subsequently recover depreciation expense and costs associated with CCR Compliance Projects through the ECA. CEI South will amortize the cumulative deferred balances in the regulatory asset and include the amortization amount in the ECA revenue requirements. Specific to deferred depreciation expense, CEI South proposes to amortize the deferred balance through the ECA over the remaining life of the assets that generated the depreciation expense. She stated that CEI South has incurred and will continue to incur costs associated with the development of the solutions which generated the design and implementation of the CCR Compliance Projects. These costs have been and will continue to be debited to FERC Account 107, Construction Work in Progress, and included for recovery within the ECA.

CEI South proposes to accrue PISCC on all eligible new capital investment, beginning with the month after the investment is placed in service until the date when the investment is included in rates for recovery. The deferred PISCC balance accumulating in the regulatory asset will be included as new capital investment and will be multiplied by the pre-tax rate of return within the ECA revenue requirement. Ms. Gostenhofer stated that the PISCC rate used is the WACC required by the ECA revenue requirement.

Ms. Gostenhofer stated that CEI South will calculate a revenue requirement for the ECA mechanism in each annual ECA filing. The revenue requirement will be shown on Schedule 1 and will include the return on new capital investments, property tax, depreciation, and O&M associated with the CCR Compliance Projects, by category of investment, and the recovery of the regulatory assets recorded through the interim deferral of depreciation expense, plan development expense, and PISCC. CEI South will then multiply the annual revenue requirement by 80% to calculate the recoverable portion of the revenue requirement for approved investments in the ECA. The recoverable amounts for the approved investments will be aggregated and included in CEI South's annual ECA rates and charges based on annualized billing determinants. She stated that CEI South is not proposing an ECA revenue requirement amount for recovery in this proceeding.

Ms. Gostenhofer testified that, pursuant to Ind. Code § 8-1-8.4-7, CEI South will seek timely recovery of all federally mandated costs associated with the CCR Compliance Projects, including capital costs, AFUDC, PISCC, O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in CEI South's next rate case.

Ms. Gostenhofer also stated that CEI South proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during construction of eligible CCR Compliance Project investments. Under this proposal, CEI South will recover, through the ECA, financing costs incurred during the construction period attributable to eligible capital investments. CWIP ratemaking treatment allows a utility to recover its costs in a timely manner and avoid the impacts of regulatory lag by recovering financing costs as the capital costs are being incurred. In connection with CWIP ratemaking treatment, CEI South will remove from the AFUDC-eligible balance the amount of investment included in the revenue requirement for the ECA, such that only the amount of CCR Compliance Project investment not currently being recovered in ECA rates or deferred in a regulatory asset for future recovery in base rates would be eligible for AFUDC.

None of the other parties in the case opposed CEI South's proposed recovery of federally mandated costs for the CCR Compliance Projects.

Based on the evidence of record, we find that CEI South's request for approval to adjust its authorized net operating income to reflect approved earnings associated with the CCR Compliance Projects for the 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). CEI South is authorized to defer and recover 80% of the approved federally mandated costs incurred in connection with the CCR Compliance Projects through the 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. In addition, CEI South is authorized to utilize CWIP ratemaking treatment for the CCR Compliance Projects through the ECA mechanism. CEI South is authorized to defer post-in-service costs of the CCR Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes, and O&M expenses, on an interim basis until such costs are recognized for ratemaking purposes through CEI South's ECA mechanism or otherwise included for recovery in CEI South's base rates in its next general rate case. CEI South's proposed cost allocation factors are also approved.

CEI South is not seeking authority to accrue and subsequently recover in the next base rate case PISCC on the balance of the 20% deferred revenue requirement included in the regulatory asset discussed previously.

ii. Depreciation. CEI South proposes to include for recovery the depreciation expense associated with the new capital investments for the CCR Compliance Projects at the current applicable depreciation rate for the asset class. To the extent the new investment associated with the CCR Compliance Projects results in the retirement of an existing asset, depreciation expense included in the revenue requirement will be reduced by the depreciation expense attributed to those retired assets. In its next base rate case, CEI South will evaluate adjustments to current depreciation rates as part of its formal depreciation study.

While no party opposed CEI South's proposed depreciation rate for the investments required for the CCR Compliance Projects, the OUCC took issue with CEI South's proposed accounting treatment for retired assets. Mr. Lantrip recommend excluding the costs of removal from CEI South's proposed retirement adjustment because the cost of removal is already considered as part of the process of establishing the depreciation rates approved in CEI South's base rate cases. He testified that the OUCC's recommendation is consistent with the Commission's order in *Indiana Michigan Power Company*, Cause No. 44182 (July 17, 2013).

On rebuttal, Ms. Gostenhofer testified that CEI South follows the FERC USOA "Electric Plant Instruction" 10(B)(2), which requires that the retirements of utility plant be recorded against the accumulated depreciation applicable to such property and that any incremental cost of removal and any salvage proceeds be charged or credited to the same account. The accounting treatment results in no change to overall rate base. Ms. Gostenhofer testified that Petitioner is not requesting to deviate from the FERC USOA for the accounting treatment of retirement. She stated that, when the FERC accounting for retirements, including the cost of removal, is applied, the retirement of an asset does not result in a change in net rate base, but results in a reclassification from plant in service to accumulated depreciation. She stated that CEI South intends to record any incurred cost of removal associated with the retired assets to accumulated depreciation, as required by FERC.

According to Ms. Gostenhofer, when depreciation expense, inclusive of cost of removal, is recorded, the balance of the amounts expensed for cost of removal aggregates in accumulated depreciation and ultimately decreases the net book value of the asset. She said that recording depreciation expense with the cost of removal both reduces rate base and also results in an accumulated depreciation reflecting a net credit balance on the plant asset or an over-depreciated asset equal to the total estimated cost of removal at the end of an asset's life. She testified that, when the actual costs of removal are incurred, the utility charges accumulated depreciation in accordance with the USOA, reducing the net plant balance to zero after incurring the cost of removal, assuming the estimated cost of removal in depreciation expense is equal to the actual costs of removal. Ms. Gostenhofer explained that any over- or under-recovery of the cost of removal will remain in accumulated depreciation, will continue to increase or decrease rate base, and will eventually be reflected in future depreciation rates determined in CEI South's next depreciation study.

Ms. Gostenhofer confirmed on rebuttal that it is not CEI South's intent to reflect in its rate adjustment mechanism the costs of removal associated with retired property. She testified that the ECA will recover the incremental capital spend and does not include an adjustment, or additional recovery, for the costs of removal.

We find that the ECA to recover the federally mandated costs associated with the approved CCR Compliance Projects should not include cost of removal for associated retirements. Based on the evidence presented, we find CEI South's depreciation proposal is reasonable and is approved.

8. Collaborative Process. In the Commission's order in Cause No. 45109, in which we reviewed CenterPoint Energy, Inc.'s acquisition of Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company, we encouraged consideration of an engagement of interested stakeholders in a collaborative process to develop open and transparent dialogue on utility operational efficiency. *Indiana Gas Company, Inc.*, Cause No. 45109, at 12 (Jan. 16, 2019). We further that encouragement here with a directive.

The Commission views the collaborative process as an opportunity for all parties to communicate on how to review utility operations. A collaborative process is currently in place for all Indiana investor-owned electric utilities except Petitioner. We believe performance metrics can be of significant value to CEI South, its customers, and the Commission. Thus, we find that CEI South shall facilitate a meeting with interested stakeholders within 12 weeks of the effective date of this order to collaborate on a path for moving forward with a performance metrics initiative. We anticipate that this process will enable an analysis of CEI South's performance over time and comparison with similarly situated utilities.

Because the ongoing collaborative effort will not be occurring in the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, the Commission's technical staff shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and 1-1.5-4. So that the Commission and interested stakeholders may stay apprised of the collaborative process, we direct CEI South to make a progress update filing in this Cause within 90 days of the initial meeting of the collaborative. We also direct CEI South to file quarterly reports for the first year and an annual report one year from the date of this order and on that date every year thereafter until otherwise indicated by the Presiding Officers.

9. Confidentiality. CEI South filed motions for protection and nondisclosure of confidential and proprietary information on June 17, 2021, December 7, 2021, and December 20, 2021. The Industrial Group also filed a motion for protection and nondisclosure of confidential and proprietary information on November 19, 2021. All of these motions related to information CEI South claimed to be trade secrets and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. Docket entries were issued on July 1, 2021 and January 11, 2022, 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 that is the subject of these motions is confidential 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. CEI South is issued a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct two natural gas CTs providing approximately 460 MW of capacity to be located at CEI South's existing A.B. Brown site. This Order constitutes the certificate. This certificate is subject to the limitations described herein regarding the Notice to Proceed date under Petitioner's contract with Kiewit.

2. Should Petitioner reach the conclusion that it should not move forward with the NTP under the contract with Kiewit because of emergent concerns not considered herein, it shall submit a compliance filing in this Cause describing its decision no later than 15 days before the Final Anticipated NTP date.

3. If Petitioner issues a "limited" NTP to Kiewit as discussed herein, Petitioner shall submit a compliance filing in this Cause within 15 days of the issue date.

4. CEI South's estimated total cost of the CT Project in the amount of $334 million is approved as set forth herein.

5. CEI South's request for ongoing review of the CT Project is approved. CEI South shall file reports as described herein for the purpose of ongoing review in accordance with Ind. Code § 8-1-8.5-6.

6. CEI South shall file supply chain updates as described herein.

7. CEI South is authorized to depreciate the CT Project at the depreciation rate identified herein.

8. CEI South is authorized to defer depreciation and to accrue PISCC related to the CT Project, including carrying costs based on its weighted average cost of capital, until such costs are recognized for ratemaking purposes through CEI South's base rates in its next general rate case.

9. To the extent that reasonable pipeline costs allocated to CEI South's customers are not ultimately recovered through CEI South's FAC mechanism, we grant its alternative request for deferral of such costs until such costs are recovered through base rates following a general rate case

10. CEI South is issued a certificate of public convenience and necessity for the CCR Compliance Projects pursuant to Ind. Code ch. 8-1-8.4. This Order constitutes the certificate.

11. The CCR Rule and the ELG Rule constitute federally mandated requirements as defined by Ind. Code § 8-1-8.4-5.

12. The CCR Compliance Projects constitute compliance projects as that term is defined in Ind. Code § 8-1-8.4-2, and the costs incurred in connection with the CCR Compliance Projects are federally mandated costs as that term is defined in Ind. Code § 8-1-8.4-4. The federally mandated costs are eligible for ratemaking treatment described in Ind. Code § 8-1-8.4-7.

13. CEI South's cost estimates for the CCR Compliance Projects set forth above are approved.

14. CEI South is authorized to timely recover 80% of the approved federally mandated costs incurred in connection with the CCR Compliance Projects through its existing ECA mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on its weighted average cost of capital.

15. CEI South is authorized to utilize CWIP ratemaking treatment for the CCR Compliance Projects through its ECA mechanism.

16. CEI South is authorized to accrue AFUDC relating to the CCR Compliance Projects until such time as the projects included in the CCR Compliance Projects are placed into service or receive ratemaking treatment.

17. CEI South is authorized to accrue PISCC related to the CCR Compliance Projects, including carrying costs based on its WACC, and to defer depreciation, taxes, and O&M expenses on an interim basis until such costs are recognized for ratemaking purposes through CEI South's ECA or otherwise included for recovery in CEI South's base rates in its next general rate case.

18. CEI South is authorized to adjust its authorized net operating income to reflect any approved earnings associated with the CCR Compliance Projects for the purposes of Ind. Code § 8-1-2-42(d)(3), as allowed under Ind. Code § 8-1-8.4-7(c)(1).

19. CEI South is authorized to defer 20% of the federally mandated costs incurred in connection with the CCR Compliance Projects for recovery in its next general rate case.

20. CEI South is authorized to depreciate the individual projects included in the CCR Compliance Projects according to depreciation rates set forth herein.

21. CEI South is authorized to record all PISCC and deferred depreciation authorized herein as regulatory assets in Account 182.3, Other Regulatory Assets.

22. A subdocket shall be created to address cost recovery and allocation issues related to the costs incurred pursuant to the Precedent Agreement with TGT as discussed herein. In the event CEI South is ultimately not permitted to reflect the fixed lateral demand charge in its FAC as a result of such subdocket, CEI South is authorized to defer as a regulatory asset for future recovery the demand costs it incurs until such time as such costs are recovered through CEI South's base rates.

23. Within five business days of the FERC order regarding the construction of the gas lateral, CEI South shall file a copy of the order under this Cause.

24. CEI South shall establish a collaborative process as discussed herein.

25. The Confidential Information submitted under seal in this Cause pursuant to the parties' 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.

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

<u>HUSTON, FREEMAN, KREVDA, AND ZIEGNER CONCUR</u>:

APPROVED: JUN 28 2022

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

Dana Kosco

Digitally signed by Dana Kosco
Date: 2022.06.28 14:12:34 -04'00'

Dana Kosco
Secretary of the Commission