FILED
March 18, 2022
INDIANA UTILITY
REGULATORY COMMISSION

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**

<u>JOINT INTERVENORS' SUBMISSION OF PROPOSED ORDER</u>

The attached Proposed Order is filed on behalf of the following parties to this proceeding: the Indiana Office of Utility Consumer Counselor ("OUCC"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Sierra Club, and Sunrise Coal (together, "Joint Intervenors"). Joint Intervenors request the Commission deny Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South's request for the construction of two combustion turbines.

Respectfully submitted on behalf of Joint Intervenors,

Jennifer A. Washburn

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 18th day of March, 2022, to the following:

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Respectfully submitted,

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<u>ORDER OF THE COMMISSION</u>

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

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On June 17, 2021, Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "Company", or "CEI South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for two new natural gas combustion turbines ("CTs") providing 460 MW of capacity ("CT Project") pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects related to its A.B. Brown, Warrick Unit #4, and Culley Plants pursuant to I.C. ch. 8-1-8.4.

Also on June 17, 2021, Petitioner filed the direct testimony, attachments and workpapers of the following Company witnesses:

- Steven C. Greenley, Senior Vice President of Generation Development for CenterPoint Energy, Inc. (Pet. Ex. 1)
- Wayne D. Games, Vice President Power Generation Operations (Pet. Ex. 2)
- Angila M. Retherford, Vice President, Environmental and Corporate Responsibility (Pet. Ex. 4)
- Matthew A. Rice, Director of Indiana Electric Regulatory and Rates (Pet. Ex. 5)
- Paula J. Grizzle, Director of Gas Supply and Portfolio Optimization (Pet. Ex. 8)
- Kara R. Gostenhofer, Director & Assistant Controller (Pet. Ex. 9)
- Rina H. Harris, Director of Energy Solutions and Business Services (Pet. Ex. 10)
- F. Shane Bradford, Director of Power Supply Services (Pet. Ex. 11)

On that date, Petitioner also filed the direct testimony and attachments of the following additional witnesses:

- Erin M. Carroll, Senior Vice President, PowerAdvocate (Pet. Ex. 3)
- Nelson Bacalao, Principal Consultant, Siemens PTI (Pet. Ex. 6)
- Jason A. Zoller, Chief Engineer, Black & Veatch (Pet. Ex. 7)

Petitioner filed corrections to its direct testimony, attachments and workpapers on September 29 and 30, 2021.

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

A public field hearing was held in Evansville on October 13, 2021, at which time members of the public presented testimony.

On November 19, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") and other Intervenors filed the testimony and attachments of their respective witnesses as follows:

OUCC

- Peter M. Boerger, PhD, Senior Utility Analyst, Electric Division (Pub. Ex. 1)
- Anthony A. Alvarez, Utility Analyst, Electric Division (Pub. Ex. 2)
- Cynthia M. Armstrong, Senior Utility Analyst, Electric Division (Pub. Ex. 3)
- Kaleb G. Lantrip, Utility Analyst, Electric Division (Pub. Ex. 4)

Industrial Group

- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. (Industrial Group Ex. 1)

CAC

- Kerwin L. Olson, Executive Director of CAC (CAC Ex. 1)
- Anna Sommer, Principal, Energy Futures Group (CAC Ex. 2 and 2-C)
- Josh Keeling, Director, Cadeo Group (CAC Ex. 3)

Sierra Club

- Michael Goggin, Vice President, Grid Strategies, LLC (Sierra Club Ex. 1)

Sunrise Coal

- Emily S. Medine, Principal, Energy Ventures Analysis, Inc. (Sunrise Coal Ex. 1)
- Michael J. Nasi, Partner, Jackson Walker L.L.P. (Sunrise Coal Ex. 2)
- Tommy L. Sutton, Engineering Manager, Sunrise Coal, LLC (Sunrise Coal Ex. 3)

The OUCC also filed written consumer comments with its prefiled evidence on November 19, 2021 (Pub. Ex. 5) and additional consumer comments on January 19, 2022 (Pub. Ex. 6). Pursuant to separate Motions granted by the Indiana Utility Regulatory Commission ("Commission" or "IURC"), CAC filed supplemental testimony of Ms. Sommer (CAC Ex. 4) on November 22, 2021 and Sunrise Coal filed supplemental testimony of Mr. Sutton (Sunrise Coal Ex. 4) on December 17, 2021. OUCC filed corrections on December 9, 2021. CAC filed corrections and/or fewer redacted versions on December 17, 2021 and January 20, 2022.

On December 20, 2021, CEI South filed rebuttal testimony, attachments and workpapers of Mr. Greenley (Pet. Ex. 1-R), Mr. Games (Pet. Ex. 2-R), Ms. Retherford (Pet. Ex. 4-R), Mr. Rice (Pet. Ex. 5-R), Ms. Grizzle (Pet. Ex. 8-R), Ms. Gostenhofer (Pet. Ex. 9-R), Ms. Harris (Pet. Ex. 10-R), Mr. Bradford (Pet. Ex. 11-R) and Steven A. Hoover, Regional Director of Gas Engineering (Pet. Ex. 12-R). On January 21, 2022, Petitioner filed further corrections to its direct testimony as well as corrections to rebuttal testimony.

On January 14, 2022, the Commission issued a Docket Entry requesting that Petitioner file certain attachments to its Engineering, Procurement, and Construction Agreement filed as Attachment WDG-R4 to Petitioner's Exhibit 2-R, to which Petitioner filed its response on January 18, 2022 (Pet. Ex. 13).

The Commission set this matter for an evidentiary hearing to commence on January 26, 2022. Upon an unopposed Joint Motion by Sierra Club, CAC, Sunrise Coal and Industrial Group requesting a remote hearing due to the continuing COVID-19 pandemic and the Omicron variant of the SARS-CoV-2 virus, the Commission issued a Docket Entry on January 21, 2022 granting the Motion and ordering the hearing to be conducted via WebEx, with access for the public to watch live via a YouTube link posted on the Commission's website. The evidentiary hearing commenced on January 26, 2022 at 10:30 a.m., 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. Stipulations of fact and evidence included:

The Commission, having heard the evidence and being duly advised, now finds as follows:

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 I.C. § 8-1-2-1(a) and I.C. § 8-1-8.5-1, an "energy utility" as defined in I.C. § 8-1-8.4-3, and an "eligible business" as defined in I.C. § 8-1-8.8-6. Petitioner is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to I.C. chs. 8-1-8.5 and 8-1-8.4, Petitioner may seek Commission approval of a Certificate of Public Convenience and Necessity ("CPCN"). Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding in the manner and to the extent provided by laws of the State of Indiana.

2. <u>Petitioner's Characteristics and System</u>. Petitioner CEI South is an operating public utility incorporated under the laws of the State of Indiana and has its principal office at 211 NW Riverside Drive, Evansville, Indiana. CEI South has charter power and authority to engage in, and is engaged in the business of, rendering retail electric service solely within the State of Indiana under indeterminate permits, franchises, a necessity certificates heretofore duly acquired. 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 seven counties: Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick and Spencer counties. Petition ¶1. To provide reliable electricity to its customers, CEI South's current generation portfolio consists of 1,032 MWs of coal fired generation which includes 32 MWs associated with a 1.5% ownership in the Ohio Valley Electric Cooperative and 150 MWs associated with 50% ownership in Warrick Unit #4 operated by Alcoa Power Generating, Inc. or its affiliates ("Alcoa"). The portfolio also contains 160 MWs of natural gas peaking generation, 54 MWs of solar (not including up to 300 MWs of solar projects recently modified following the Final Order in Cause No. 45501), 3 MWs of landfill gas, 1 MW of battery storage and two wind PPAs totaling 80 MWs. This equals a total of 1,330 MWs of installed capacity. Petition ¶10.

CEI South's operations are subject to federal, state and local rules promulgated by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from CEI South's electric generating units. Petition ¶5.

3. <u>Evidence</u>.

A. CEI South's Case in Chief. *[We adopt CEI South's summaries of its own witnesses, except where testimonial statements are written as factual]*

B. Indiana Office Utility Consumer Counselor's Case in Chief.

i. <u>Peter M. Boerger, PhD, Senior Utility Analyst, Electric Division (Pub. Ex. 1)</u>.

OUCC witness Dr. Peter M. Boerger, Senior Utility Analyst, presented testimony regarding the economic justification for the combustion turbines proposed by Petitioner. First, Dr. Boerger pointed out the importance of CPCN decisions to the affordability of utility rates. He then discussed the need for dispatchable resources as the amount of intermittent resources grows in the coming years, and, referencing the testimony of OUCC witness Alvarez, noted that the capacity provided by retrofitting CEI South's A.B. Brown facility to burn gas would meet CEI South's stated need for dispatchable capacity. Dr. Boerger then presented his evaluation of the economic modeling of such a gas conversion option in CEI South's IRP modeling.

Dr. Boerger identified a number of concerns about CEI South's modeling. First, Dr. Boerger pointed to evidence that CEI South's modeling showed shared economies in its treatment of a second CT unit but did not provide similar treatment for a second gas-converted unit. Based on this incongruous treatment, Dr. Boerger stated his belief that contrary to CEI South's modeling results, converting both A.B. Brown units to gas were they to be properly modeled, would be more economic than converting only one unit. He went on to evaluate such a two-unit conversion, comparing it to CEI South's proposal to replace the A.B. Brown units with two CT units.

Dr. Boerger identified a number of errors and omissions in CEI South's modeling. By performing a comparison of AES Indiana's experience with conversion of its Harding Street units to gas, Dr. Boerger identified that CEI South's modeling overestimated the costs of operating and maintaining the units after conversion. This overestimation was present even after accounting for CEI South's inclusion of a large expenditure for solid particle erosion, a future expense that was modeled by CEI South but for which CEI South admitted that it performed no study.

Dr. Boerger noted that CEI South made an error in its modeling by removing the effects of inflation from its expected future cash flows, but not from the rate that it used to discount those cash flows. While the effect of this issue could not be identified without rerunning the model, he noted that this issue would have the potentially significant effect of overvaluing costs (and benefits) in the near term while undervaluing such cash flows further in the future.

Dr. Boerger also testified regarding the 10-year lifespan CEI South assumed in its modeling for the A.B. Brown units after gas conversion. In response to OUCC discovery, CEI South admitted that no studies were performed to justify such a limited life. Dr. Boerger pointed out that CEI South's capital cost support showed that gas conversion units were burdened with closure costs for A.B. Brown units, but the calculations of costs for its CT proposal showed no reflection of such costs. Dr. Boerger also noted an apparent error with CEI South's use of a capital recovery factor in valuing the capital costs of the CT units.

Finally, Dr. Boerger presented the results of an OUCC review of potential tax effects resulting from the use of securitization, which CEI South presented as a benefit to retiring the A.B.

Brown units instead of converting them to gas. Dr. Boerger estimated that the true economics of the gas conversion versus the CT options are very close. However, he noted that in CEI South's modeling CTs require a 30-year life to achieve their economic result, whereas gas-converted A.B. Brown units only require 10 years to achieve those results. Thus, given the significant changes occurring in the electric utility industry, especially around the future treatment of natural gas as a generation fuel in the long run, Dr. Boerger noted the risk of having stranded costs related to the combustion turbine option, just as there are stranded costs today related to the A.B. Brown units. Given that gas-converted units meet CEI South's need for dispatchable capacity and the fact that CEI South has already conducted studies verifying the ability of A.B. Brown units to be converted, Dr. Boerger concluded that the most prudent course of action would be to deny CEI South's request for a CPCN to construct the proposed CTs, while pointing CEI South toward the gas conversion option.

ii. Anthony A. Alvarez, Utility Analyst, Electric Division (Pub. Ex. 2).

Mr. Anthony A. Alvarez, Utility Analyst, addressed CEI South's request for approval to construct two natural gas simple cycle combustion turbines in this proceeding. He described CEI South's proposed 460 MW simple cycle combustion turbines ("CT Project") and evaluated the CT Project's cost estimate. He addressed the functional and operational characteristics of CEI South's proposed CT project and its existing simple cycle turbine assets and discussed why CEI South's proposed CT Project is not a good choice for ratepayers. He described refueling the coal-fired A.B. Brown units to gas-fired as a viable and cost-effective alternative for CEI South and its ratepayers and analyzed the gas conversion technology as a less-expensive alternative option available to enhance and extend the life of the A.B. Brown legacy generating units. Finally, Mr. Alvarez recommended the Commission deny CEI South's proposed CT Project and encourage CEI South to adopt the more reasonable alternative of refurbishing and refueling the A.B. Brown generating units to gas.

Mr. Alvarez testified that despite CEI South's flexibility claims, the simple cycle gas combustion turbine technology employed in CEI South's proposed CT Project was the most restrictive in terms of utility-scale electricity generation because of its relatively low efficiency and operational functionality. He stated the simple cycle turbines perform in a narrow role as peaker generators because the technology and design of these machines did not allow them operate long durations throughout the year. He explained CEI South claims that the proposed CT Project will support intermittent renewable resources being developed across Midcontinent Independent System Operator ("MISO") Zone 6 and will allow other Indiana utilities to meet their peak loads when energy from renewables is insufficient. However, he testified that MISO, not CEI South, has the authority to decide which generators to dispatch and serve the demand and load within its footprint. As peaker class generators, Mr. Alvarez stated simple cycle turbines were projected by CEI South to have inherently low Capacity Factors ("CF"), and because they were very expensive to run with relatively low efficiency characteristics, they were the last generators MISO dispatches.

Mr. Alvarez pointed out that CEI South's system peak demand has been declining since 2013, showing a compound annual growth rate of -2.7% (2013-2020). He stated despite a contracting system demand, CEI South's long-term plan remained misaligned and focused on increasing rate base, which is and will be detrimental to its relatively small customer base. He testified CEI South has had the overall highest residential rates among the five Indiana investor-owned utilities ("IOU") from 2017 to 2021 in the Commission's annual residential bill survey (based on Total Rate of customers consuming 1,000 kWh). He explained instead of selecting a plan to extend the life of its existing generation assets and mitigate rate base increases, CEI South seeks to retire and replace high performance generators with expensive simple cycle turbines, thereby expanding its rate base. Mr. Alvarez stated CEI South has two existing simple cycle turbine generating units, A.B. Brown Units 3 & 4. These units are 80 MW simple cycle turbines that in the last seven years (2014 through 2020) generated and injected electricity to the grid only a few hundred hours per year. He concluded CEI South expects the same disappointing performance from its proposed CT Project.

Mr. Alvarez testified the proposed CT Project is not the appropriate available alternative option to replace the coal-fired 490 MW A.B. Brown units. He stated CEI South did not consider comparing, evaluating and assessing the performance of the gas conversion alternative option with similar existing generating units in Indiana. He explained CEI South handicapped and eliminated a viable alternative option by assigning it a shorter useful life in its analysis. He described the gas-fired conversion and refueling technology as an adoptable, viable and cost-effective alternative to refurbish the coal-fired A.B. Brown legacy units and provide CEI South and its customers with capacity. Mr. Alvarez concluded the Commission should deny CEI South's proposed CT Project and require CEI South to pursue the viable and cost-effective alternative of refurbishing, converting, and refueling the A.B. Brown legacy units to gas.

Mr. Alvarez discussed the lessons learned from Cause No. 45052, CEI South's last request for new generation. In the Cause No. 45052 Order, the Commission found Petitioner failed to "fully consider options to extend the life, or refurbish, existing units" and such "failure began during Vectren South's IRP [Integrated Resource Planning] process," when Vectren "screened out, without further sturdy, viable refurbishment options." *In re Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc*., Cause No. 45052, 2019 WL 6770066, *24 (Ind. Util. Regul. Comm'n April 24, 2019) ("*Cause No. 45052*"). He stated that from a perspective of "minimizing risk and providing future flexibility," the Commission found "the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated" by the Petitioner. *Id.* Ultimately, the Commission denied CEI South's request for a CPCN to install an 850 MW combined cycle gas turbine ("CCGT") in Cause No. 45052.

Mr. Alvarez testified that Petitioner's witness Mr. Steven G. Greenley stated the lessons learned from the Cause No. 45052 Order guided CEI South. He stated that Mr. Greenley acknowledged the need for CEI South to "consider refueling [A.B.] Brown" and "incorporate flexibility in the modeling" by not screening out multiple less expensive alternatives as among the lessons learned. He explained that although CEI South did not "screen-out" less expensive alternatives in this case, it imposed an unreasonable burden on the alternative option of refueling the A.B. Brown units with higher cost estimates than its own previous refueling estimates in Cause No. 45052. He further explained CEI South imposed additional operational restrictions so that the capabilities of the alternative option appear unviable for CEI South's purposes. Mr. Alvarez also compared the generators CEI South proposed in Cause No. 45052 and its proposal in this proceeding. He concluded, by comparison, CEI South's proposal in this Cause was simply a "stripped down" version of its previous CCGT proposal, which took away the heat recovery steam generator ("HRSG") and retained the two simple cycle turbines.

Mr. Alvarez testified on the issue of refurbishing existing facilities as considered by the Commission's findings in Cause No. 45052. He stated central to the Commission's discussion and findings was the requirement in I.C. § 8-1-8.5-4(b)(2) for the Commission to consider other methods of providing reliable, efficient, economical electric service including "the refurbishment of existing facilities[.]" He reviewed and evaluated CEI South's proposed CT Project and assessed Mr. Greenley's claims of using the lessons learned from the 45052 Order for guidance in this Cause. He researched and evaluated the performance of other existing refurbished and refueled coal-fired to gas-fired converted units with nominal capacity ranges like the A.B. Brown units.

Mr. Alvarez provided a brief overview of CEI South's proposed CT Project. He stated CEI South proposed to construct and install two natural gas simple cycle combustion turbine generators with a combined capacity output of 460 MW to replace a portion of the 490 MW coal fired A.B. Brown Units 1 & 2. He also stated CEI South proposed to diversify its generation asset portfolio by adding two F-Class natural gas CTs (the CT Project) at the A.B. Brown site "with an in-service date of fourth quarter 2024." Mr. Alvarez testified the simple cycle turbines are not base load generators and are projected to have a low capacity factor but are designed to provide fast start and fast ramping capability. He explained the CT Project has a cost estimate of $323 million consisting of an Engineering Procurement and Construction ("EPC") Estimate, Owner's Costs (including project management, owner's engineer, and regulatory or permitting costs), Escalation Costs, and Planning and Development Costs, among other costs. He further explained the CT Project cost estimate does not include the costs of the required pipeline and emission control equipment and CEI South negotiated a 20-year service contract with Texas Gas Transmission LLC. to construct 24 miles of 20-inch pipeline lateral and place the pipeline lateral in-service by 2024 to serve the CT Project.

Mr. Alvarez evaluated the $323 million proposed CT Project cost estimate presented by Petitioner's witness Wayne Games. He testified that based on the cost information Mr. Games provided, the CT Project yielded a capital cost of $702 per kilowatt ("kW"). He provided his Table 1 showing the EPC Estimate ($188 million), Owner's Total Cost ($135 million), and Total Cost Estimate ($323 million) of the CT Project. Mr. Alvarez also evaluated the EPC cost estimate and the technical specifications of the simple cycle GE 7F.05 gas turbines provided in Petitioner's Exhibit No. 7, Petitioner's witness Jason A. Zoller. Mr. Alvarez calculated a higher capital cost of $720 per kW (compared to Mr. Games' $702 estimate) for the CT Project. He then compared Messrs. Games' and Zoller's estimates to the range of overnight capital cost estimates for gas peakers using Lazard's Levelized Cost of Energy Analysis, Version 14.0 (2020) ("Lazard LCOE V.14.0"). He provided his Table 2 with the tabulated results showing Messrs. Games' and Zoller's capital cost estimates were at the lowest end of Lazard capital cost range for a gas peaker ($702 - $925 per kW). Mr. Alvarez took into consideration the fact that the Lazard capital cost range for gas peakers did not include any interest, financing, or escalation costs, and Mr. Alvarez stated it appeared anomalous for CEI South's estimate to be at the lower end of the range.

Mr. Alvarez provided his Table 3 and compared Messrs. Games' and Zoller's estimates to the range of overnight capital cost estimates for gas peakers using the U.S. Energy Information Administration ("EIA") base and regional overnight capital cost for new electricity generating technologies. He stated compared to EIA's base and regional overnight capital costs, CEI South presented an unrealistically low estimate for the CT Project. He concluded that if this is the case, CEI South was artificially bolstering the CT Project's chances of receiving the Commission's approval by providing an unrealistically low-cost estimate and not disclosing the high degree of risk for cost escalation the CT Project is carrying, simultaneously exposing its ratepayers to the risk of subsequent cost increases.

Mr. Alvarez testified the lack of emission control equipment in the CEI South's CT Project cost estimate does not explain the discrepancy against benchmarked capital costs; rather, such deficiency earmarks the unreliability of CEI South's cost estimate. He explained CEI South's ratepayers are sensitive to large scale, rate base-expanding capital projects due to the outsized rate impact it will cause on CEI South's small customer base (approximately 140,000), who are already experiencing high residential electricity rates. He provided his Table 4 that summarized and ranked (1 being highest and 5 being lowest) the five Indiana Investor-Owned Utilities ("IOUs") based on simple tariff rates paid by residential customers who use 1,000 kWh per month for the period 2017 to 2021. His Table 4 showed CEI South has consistently topped the Commission's annual residential bill survey in the last five years 2017 to 2021 with the overall highest residential rates among the five Indiana IOUs based on the Commission's Electricity Bill Survey, "Total Rate at 1,000 kWh consumption." Mr. Alvarez stated CEI South's customer base is less than a third of the size of the next IOU. He explained as a smaller-sized electric utility with ratepayers already paying high electric rates, CEI South should consider its ratepayers' diminished capacity to carry the additional burden of paying for big ticket items such as the acquisition of new generation. He concluded CEI South chose a proposal that expanded its rate base considerably (by 20%), rather than other more cost-effective alternatives.

Mr. Alvarez discussed his research and evaluation of the technology and design characteristics, attributes, and operational capabilities of the CT Project's GE 7F.05 gas turbine simple cycle configuration in a utility scale power generation application compared to other bulk electrical and industrial systems applications. He provided his Table 5 showing the Applications, Advantages, and Disadvantages of the GE simple cycle gas turbines based on the information from GE Gas Power. He testified that from a utility-scale power generation perspective, CEI South's proposed CT Project would operate in a simple cycle configuration and primarily as a peaker because of the disadvantages inherent to this type of generators, such as lower efficiency and higher specific emissions, which limited its operations or run time to short durations only. He stated GE expects its simple cycle 7F.05 gas turbines to perform with a net efficiency lower than 40%.

Mr. Alvarez discussed his evaluation of the fast start and ramp rate characteristics of CEI South's proposed CT Project and explained there is nothing special about these capabilities because such capabilities were expected or typical of peaker generation units and these generators compete and operate against similar peaker units in a narrow role characterized by a relatively low position in the dispatch stack (last in the dispatch merit order). He stated that even with the capabilities, the inherent disadvantages of a simple cycle gas turbine (i.e., relative lower efficiency and higher emissions) make it too expensive to dispatch and operate and puts it at the tail-end position of the dispatch merit order of generators. He concluded when compared to other types of utility-scale generator technologies used as base load, intermediate load, and peaker units, the simple cycle gas turbines, such as CEI South's proposed CT Project, were not expected to operate long durations on an annual basis.

Mr. Alvarez addressed CEI South's claim the features of the simple cycle 7F.05 gas turbines, among others, would allow CEI South "to install large volumes of renewable energy[.]" He testified CEI South's ability to deploy more renewable energy is not dependent at all on the features of the simple cycle 7F.05 gas turbines but rather, as a load serving entity ("LSE") and member of MISO, CEI South is expected to have sufficient generation capacity to serve its load and reserve margin requirements. He concluded it is these needs and requirements that drive the demand for any additional or new generation capacity, renewable or otherwise, and not the features of a simple cycle turbine.

Mr. Alvarez testified CEI South's demand has continued to decline and does not support the need for additional or new capacity. He provided his Table 6 showing CEI South's system peak demand (MW) from 2013 through 2020. He stated based on its historical peak load for the period 2013 through 2020, CEI South's system did not experience any appreciable load growth, instead experiencing continued decline with a negative growth rate (-2.7%) during the period. Mr. testified CEI South did not incorporate its continued negative growth rate into its long-term plan. He explained while its system demand was experiencing a negative growth rate, CEI South's long-term plan was based on the unfounded premise of expanding demand and despite the continued decline in system demand since 2013, in Cause No. 45052 and in its 2016 Integrated Resource Plan ("IRP"), CEI South forecasted energy and demand growth of 0.5% beyond 2019. Mr. Alvarez testified even after the continued downward trend of its system demand in 2019 and 2020, CEI South forecasted an even higher energy and demand growth rate of 0.6% per year in its 2019/2020 IRP. He explained by doing so, CEI South failed to acknowledge the reality and actual needs and requirements of its system on a path of continued negative demand growth rate. It is on this basis that he supported OUCC witness Kaleb Lantrip's recommendation the Commission deny CEI South's request to defer any costs related to its misaligned 2019/2020 IRP for future recovery through retail electric rates.

Mr. Alvarez addressed how a utility's negative system demand growth rate coupled with a mismatched long-term plan adversely affect its ratepayers. He explained a utility's proposed system investment costs in its misaligned long-term plan unfairly fall on its ratepayers. He testified a smaller-scale utility facing these adverse downward-trending conditions should explore cost effective alternatives that do not require intensive capitalization and would not only extend the use of its existing assets, but still provide benefits to ratepayers. He stated, in this case, CEI South opted to grow its rate base by investing in new assets instead of taking a more sensible approach of refurbishing and extending the life of its existing assets. He explained, in the pretext of obtaining ratepayer savings, CEI South justified the construction and installation of two new simple cycle 7F.05 gas turbines by subjecting and imposing unnecessary constraints on the alternative option, thereby rendering its pre-disposed choice appear economically viable.

Mr. Alvarez addressed CEI South's statement that "[t]he CT units will not be base loaded and are projected to have a low-capacity factor, only operating when economical for the customer," while also claiming that the CT units will provide "low cost dispatchable capacity."[1] He testified CEI South used the term "capacity" loosely and compared a typical "low capacity factor" peaker unit to a "low cost dispatchable capacity" generating unit and qualified it by stating the CT will "only operate when economical for the customer." He reasoned, first, a "low-capacity factor"

[1] Pet. Ex. 2, p. 30, ll. 17 – 21

peaker unit means the CT will not be called upon or dispatched often or expected to operate long durations on an annual basis and, as such, the expected amount of electricity (in MWh) the CT would generate and inject into the grid on an annual basis is very low compared to the theoretical amount of electricity it could generate based on its nameplate rating. He explained the reason for this is peaker units are the most expensive generating unit to dispatch, thus, they are typically held off to a position of being the very last generators to be called upon to meet demand. Second, Mr. Alvarez stated, the term "capacity" in the statement related to the CT being a "low cost dispatchable capacity" pertains to generator capacity (in MW) that CEI South must hold to satisfy the MISO Planning Reserve Margin ("PRM") requirements. He explained contrary to CEI South's statement, the CT Project is *not* "low cost dispatchable capacity," considering the CT Project requires a minimum projected investment of $323 million for just 460 MW, while the refueling alternative for the 490 MW A.B. Brown units would require far less capital. Third, Mr. Alvarez stated, CEI South's statement that the CT will "only operate when economical for the customer," means there are very limited dispatch windows for peakers. He explained during days and hours when the demand and temperatures are at an extreme, and the price of electricity is high enough to render the peaker units economical to dispatch, then these generators will be called upon and brought online to meet that demand.

Finally, Mr. Alvarez stated, once peaker units are dispatched, other generators (with higher priority position in the dispatch merit order) that were dispatched ahead of the peaker units will receive the same payment rates set by the peakers. He explained after demand in the system subsides and generators are switched offline in the reversed dispatch order of merit, the peaker units are the first ones switched off, while the other generators remaining online continue to receive payments for their service. Mr. Alvarez concluded this meant a repowered A.B. Brown unit (with a relatively higher CF) would be dispatched ahead, kept running longer to serve the demand and, therefore, earn more money in the MISO market than the simple cycle turbines (with relatively lower CF) of the proposed CT Project.

Mr. Alvarez evaluated CEI South's claim the CT Project gas turbines could burn 5%-10% hydrogen and with modifications can currently burn up to 30% hydrogen, further reducing carbon emissions. He provided his Table 7 showing the infrastructure requirements for hydrogen production based on a single GE 7H.05 gas turbine. He explained based on the CT Project's requirement for two simple cycle GE 7F.05 gas turbines running on 30% hydrogen, it would require multiplying the GE estimated energy and water requirements by at least a factor of 2, thus doubling the size of the hydrogen infrastructure required. Mr. Alvarez addressed CEI South's assertion to produce green hydrogen from the nearby 300 MW solar project CEI South proposed in Cause No. 45501. He testified CEI South did not recognize the magnitude of the infrastructure needed to produce the green hydrogen required to fire the turbines and the electrolysis process' power requirement needed to produce the required amount of green hydrogen would far exceed what a 300 MW solar facility could provide when the sun is shining high and bright, much more on a 24/7, around-the-clock basis. He stated the cost to run the simple cycle turbines as peakers at a 30% hydrogen level on very limited hours per year would be exorbitant and would be unreasonable to pass on to ratepayers.

Mr. Alvarez explained the U.S. Department of Energy ("DOE") launched its first Energy Earthshots Initiative ("Hydrogen Shot") on June 7, 2021, which aims to accelerate breakthroughs of more abundant, affordable, and reliable clean energy solutions within the decade. He stated the

Hydrogen Shot seeks to reduce the cost of clean hydrogen by 80% to $1 per kilogram ("kg.") in a decade, or "Hydrogen Shot 111." He described one drawback of hydrogen as fuel for electric power generation is that it has about 30% of the energy content of methane and it takes about 3.3 cubic feet ("cu. ft.") of hydrogen to deliver the same energy as 1 cu. ft. of natural gas. He stated if the DOE is successful in achieving the goal of $1/kg. for clean (or green) hydrogen in a decade, it may still be some time before industry can produce clean hydrogen fuel at the level required for power generation. Mr. Alvarez testified it will likely take more than a decade and continuous government effort and support to bring clean hydrogen into the mainstream of viable utility-scale power generation fuels.

Mr. Alvarez addressed CEI South's claim that the dispatch of renewable resources has changed the generation stack within MISO, with the intermittency of wind and solar leaving fossil-fuel based resources to balance the system when the output of the renewable resources changes. CEI South claims this impacts the dispatch of its coal-fired generation units causing them to cycle up and down throughout the day, increasing the frequency of stop and start cycles throughout the year. Mr. Alvarez testified if CEI South's coal-fired generation units (such as the A.B. Brown Units 1 and 2) "cycle up and down throughout the day and increase the frequency of stop and start cycles throughout the year," that operation would signal a departure from dispatch as base load generators and rather as load-following generators. Therefore, it is possible to determine whether the dispatch of CEI South's coal-fired generation units changed by evaluating their CF. He researched and analyzed the unit monthly operations and evaluated the CFs of the A.B. Brown Units 1 & 2. He reviewed the monthly and annual data and information in EIA Form 913 filings collected by S&P Capital IQ Pro® and analyzed information on the U.S. coal fleet from the EIA Electric Power Monthly, Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels report released September 24, 2021. He provided his Table 8 showing the A.B. Brown Units 1 & 2 monthly capacity factors in 2021. Mr. Alvarez testified on a month-to-month basis in 2021, both A.B. Brown Units 1 and 2 operated as typical coal-fired power plants, showing no deviation from operating characteristics of base load generating units. He stated the Energy Information Administration ("EIA") data shows both A.B. Brown Units 1 and 2 outperformed the U.S. coal fleet during the winter months of 2021 and continued to remain operationally strong in succeeding months. In particular, he explained, the A.B. Brown Units 1 and 2 performed very well during the 2021 Polar Vortex period despite the chemical inventory challenges CEI South stated it experienced during that event, although such seasonal operational issues could easily be addressed and resolved with advance planning and having proper and adequate winterization plan in place. Mr. Alvarez testified contrary to CEI South's claims, there was no evidence showing these coal-fired units were cycling outside their typical operating parameters or experiencing any increase in the start and stop cycle frequency that would cause dramatic changes in their monthly CFs.

Mr. Alvarez did not agree with CEI South's conclusion that the A.B. Brown Units 1 & 2 are "among the smaller, least efficient coal units remaining in the state" as compared to other Indiana coal units. As shown in his Table 8, these units surpassed the performance of the U.S. coal fleet on a month-to-month basis this year and performed very well for CEI South ratepayers during the critical Polar Event month of February. He explained such performance was good evidence that those boilers were operating well and concluded the A.B. Brown Units 1 & 2 may be smaller in size, but they fit the needs of the customer base and system demand of smaller-sized-utility such as CEI South.

Mr. Alvarez testified when a utility proposes adding new generating capacity, I.C. § 8-1-8.5-4(b)(2) requires the Commission to consider other methods of providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. He stated in Cause No. 45052, the Commission found CEI South failed to consider options to extend the life of the existing units as a potential bridge to the future and had screened out viable refurbishment options. He stated while CEI South cited economic reasons for pursuing simple cycle combustion turbines in its 2019/2020 IRP as support for its proposed CT Project, it presented a flawed analysis suppressing the viability of the refueling of the A.B. Brown coal-fired boilers.

Mr. Alvarez testified both A.B. Brown Units 1 and 2 are rated at 245 MW net capacity with A.B. Brown Unit 1 placed in service in March 1979, and A.B. Brown Unit 2 placed in service in February 1986. He stated these coal-fired units have a full complement of coal handling and emission controls equipment such as selective catalytic reduction, low nitrogen oxide burners, and flue gas desulphurization, which represents a significant amount of "parasitic load." He explained once converted to gas-fired, the units would shed parasitic load from the coal-based equipment and regain power to maintain the same rated capacity with the added bonus of lowering emissions during startups.

Mr. Alvarez discussed the technical aspects of converting coal-fired boilers to gas, such as the alternative option of refueling A.B. Brown Units 1 and 2. He explained the last decade saw the advancement and establishment of gas conversion technology for power boilers and is considered tested and proven technology today. He stated converted power plants retain their original capacity ratings, start, ramp, cycle, and are dispatched accordingly (sometimes even faster and with better performance); and are reliable, efficient, and viable alternative options to maintain system reliability and extend the useful life of the generating asset after gas conversion. He described the technology as commercially available with leading industry vendors and suppliers having the capability to assure and provide power plant owners and operators the adaptability of the technology. He explained these offerings are backed with full scope installations, project management and worry-free offerings from initial engineering and feasibility studies up to start-up and commissioning stages, including operator and instrumentation training and regulatory compliance requirements, regardless of the coal-fired boiler's original manufacturer. Mr. Alvarez testified Indiana has the distinct advantage of having not just one but three power plants with the new and advanced gas conversion technology installed converting coal-fired boilers of different vintages and capacity ratings. He stated the performance records of these Indiana-based gas-fired converted power plants show the operational viability and cost-effectiveness of this technology in the energy and capacity markets.

Mr. Alvarez discussed the capacity ratings, vintages and gas conversion costs of the Indiana-based legacy power plants. He testified one of the goals achieved by the advancement of the gas conversion technology for power boilers in the last decade was the ability to maintain 100% of the boiler's maximum continuous rating once converted to gas. He explained the technology developments of plug-in gas burners and igniters achieved superior combustion results and overcame any typical boiler de-rating capacity loss characteristic of previous burner and component technologies and in addition, the vintage of the legacy power plants did not affect the ability of the power plants to achieve full capacity upon conversion. Mr. Alvarez testified overall, the Indiana-based legacy power plants realized the operational benefits offered by these technical advancements and extended their useful lives. He provided his Table 10 showing relevant information of the Indiana-based AES Indiana ("AESI") Harding Street Units 5, 6 and 7 before and after gas conversion. His Table 10 showed the gas conversion costs for Harding Street Unit 5 & 6 was $42.1 million ($244 per kW) and Unit 7 was $64.3 million ($178 per kW). He also provided his Table 11 comparing the gas conversion costs of A.B. Brown Units 1 & 2 to Harding Street Units 5, 6, & 7. His Table 11 showed the A.B. Brown Units 1 & 2 combined capacity as 490 MW (compared to 618 MW for the Harding Street units); conversion estimate of $119 million (compared to $106 actual cost for the Harding Street units); and conversion cost per kW of $241/kW (compared to $193/kW for the Harding Street units).

Mr. Alvarez testified AESI's Harding Street units' refueling and conversion proved there are alternative cost-effective options for meeting a utility's capacity needs. He stated the refueling and conversion of the smaller Harding Street Units 5 and 6 was the first refueling project undertaken by an Indiana utility and with the addition of the larger Harding Street Unit 7 refueling project, the three units' refueling and conversion work was done consecutively in a short time schedule with a high degree of coordination and work consolidation for efficiency to minimize conflicts and congestion at the work site. He explained although the conversion cost of the Harding Street Units 5 and 6 was $241/kW, the Harding Street Unit 7 was completed at $178/kW, below the $70.88 million cost estimate the Commission approved in Cause No. 44540 and the utility completed refueling the three units at an overall conversion cost of less than $200/kW. Mr. Alvarez testified while the engineering and design assumptions initially predicted the need to derate the units by as much as 20% -30% of their original capacity, once in commercial operation, there were no derates or outages associated with the conversions. He provided an excerpt from the May 2018 Semi-Annual Progress Report submitted to the Commission:

> Harding Street Station Units 5 & 6 have been released for commercial operation since December of 2015 and there have not been derates or outages associated with the conversions to date. The Induced Fan (ID) motor change was completed in October 2016. This concludes all major construction on this project. Punch list items are completed for Units 5 & 6.

Indianapolis Power & Light Company ("IPL"), Semi-Annual Update, May 2018, Cause No. 44339, p. 3.

Mr. Alvarez testified refueling and converting CEI South's A.B. Brown units to gas is a viable, cost-effective option and despite the magnitude of CEI South' estimates for the conversion of the A.B. Brown units ($118 million) and simple cycle turbines ($323 million), the cost of conversion and refueling still represented a very low capital cost for a viable option with a proven track record and extension of the A.B. Brown units' useful life. He stated preserving and extending the life of existing assets at a very low capital cost using proven technology provides greater service to ratepayers.

Mr. Alvarez testified the age of A.B. Brown Units 1 and 2 would not affect CEI South's ability to successfully adopt gas conversion and refuel these units and the results of CEI South's own gas conversion assessment and evaluation showed that for a low capital cost of $118 million, the A.B. Brown units could successfully be converted "from firing coal to 100 percent natural gas."[2] He explained although the A.B. Brown Unit 1 (vintage 1979) is the older of the two units, it is younger in age than the youngest AESI Harding Street gas-converted unit (Unit 7, vintage 1973) and provided his Table 12 comparing the ages of the A.B. Brown and Harding Street generating units. Mr. Alvarez testified another important aspect of this is gas conversion will definitely extend the life of the A.B. Brown units beyond the10 years life assumption CEI South assigned and used for these units in its analysis. He explained CEI South's response to OUCC discovery indicated that during its December 13, 2019, IRP stakeholder meeting, it picked a 10-year life assumption for the converted A.B. Brown units because no stakeholders suggested otherwise. He stated documents regarding the gas conversions of the Harding Street units (Cause No. 44339 and 44540) were publicly available at the Commission's Portal free of charge and readily accessible for CEI South's research. He explained IPL's "[r]efueling studies evaluated an additional ten-, fifteen, and twenty-year useful life for Harding Street 5 & 6." He concluded assigning a 10-year life assumption for the A.B. Brown conversion flawed CEI South's own analysis.

Mr. Alvarez addressed CEI South's claims there are other major expenses to continue operating the A.B. Brown units. He explained CEI South claims "[t]he A.B. Brown units are due for major turbine and generator overhauls in 2021 (unit 1) and 2022 (unit 2) at an estimated expense of $4 million - $5 million each" however, CEI South's (then Vectren) own response to question number 2, in the Commission's February 9, 2012, Docket Entry in Cause No. 44067, stated "[t]he AB Brown turbines were last overhauled in 2004. These turbines are normally overhauled on a 5- to 7-year cycle." Mr. Alvarez testified turbine and generator overhaul cycles are expected and typical of good power plant management practices by protecting and preserving ratepayers' investment whether the turbines are coal-fired, gas-fired or simple cycle. He stated if the A.B. Brown turbines and generators are due for overhaul soon, it would make sense to efficiently coordinate and consolidate the boiler conversion and refueling with the turbine and generator overhauling. He explained AESI gained efficiency by consolidating and coordinating the refueling and conversion work of the three units consecutively with a short time schedule.

Mr. Alvarez responded to CEI South's claims regarding Solid Particle Erosion ("SPE") damage to its turbine by-pass valve because of cycling. He described in Cause No. 45052, CEI South testified about converted units having incomplete combustion and in this Cause, CEI South is critical about converted units having SPE damage. He testified, as stated in his Cause No. 45052 testimony, these issues are solvable engineering problems and CEI South should bring this issue up with its boiler or turbine manufacturer prior to the next scheduled turbine and generator overhaul outage to address these issues and seek permanent solutions. Nevertheless, he stated, the preventions and solutions to these issues will become a part of the power plant's good management, operation, and maintenance practices.

Mr. Alvarez summarized the results of his analysis and evaluation. He testified the proposed CT Project is an inappropriate choice to replace the 490 MW capacity of A.B. Brown Units 1 and 2, and CEI South's analyses burdened the refueling option with unreasonable operating expenses and used a short expected-life assumption to screen out and render the refueling option undesirable in its analysis. On the other hand, CEI South bolstered the proposed CT Project with unfair flat-rate operating expenses and enhanced operating characteristics to elevate its choice for

[2] Pet. Ex. 7, p. 8, ll. 17 – 18.

selection. He stated refueling coal-fired boilers to gas-fired is a viable and cost-effective option to extend the life of the A.B. Brown legacy units and the gas conversion technology advancements in the last decade achieve the capability of maintaining 100% of the power plants' rated capacity after conversion. He further stated refueling the A.B. Brown Units 1 and 2 could be achieved at a reasonable range of around $200/kW and would require low capital outlay that protects and preserves ratepayer's interests in these existing assets. Finally, he concluded refueling the A.B. Brown Units 1 and 2 fits the requirements of a small customer base and the system demand of a small-sized utility like CEI South.

Ultimately, Mr. Alvarez recommended the Commission deny CEI South's request for a CPCN for its proposed CT Project and require CEI South to fully evaluate the refueling of the coal-fired A.B. Brown Units 1 and 2 to extend the life of these legacy units.

iii. Cynthia M. Armstrong, Senior Utility Analyst, Electric Division (Pub. Ex. 3). Cynthia Armstrong, Senior Utility Analyst in the OUCC's Electric Division, testified to environmental issues regarding the OUCC's recommendation for CEI South's requested environmental compliance projects and the Brown CTs. Specifically, she recommended denial of the proposed new CCR-compliant ponds at the Brown and Culley generating plants ("Pond Compliance Project") and approval of the Dry Ash Compliance Project. If the Commission approves the Pond Compliance Project, Ms. Armstrong offered an alternative recommendation to require CEI South to bear fifty percent of the cost of the ponds. She stated the alternative recommendation recognizes that even though CEI South's CCR obligations were known to be pending many years ago, CEI South unreasonably delayed decisions and has now submitted speculative cost estimates that could result in higher costs for consumers.

Ms. Armstrong's reasons for denying the Pond Compliance Project were 1) CEI South has not yet received approval from the Environmental Protection Agency ("EPA") that the proposed Brown and Culley ponds will allow it to qualify for the extension to use the existing Brown Ash Pond until October 2023; 2) CEI South provided inadequate cost estimates for the ponds; and 3) CEI South provided inadequate evidence that continuing to operate Brown Units 1 and 2 and Culley Unit 2 until October 2023 by constructing the new CCR-compliant ponds is less costly than immediate unit retirement.

Ms. Armstrong noted CEI South's witnesses Games' and Retherford's statements that to continue using the Culley pond until March 2023 and the Brown pond until October 2023, CEI South must pursue the fastest technically-feasible option for alternative capacity to qualify for the extension under the CCR Part A Reconsideration Rule. She acknowledged their claims that the proposed Brown and Culley 2 Ponds are the fastest technically-feasible options to provide storage for the CCR wastes Brown Units 1 and 2 and Culley Unit 2 produce and that Culley will not be able to use the existing ash ponds through October 2023 without constructing these ponds.

She stated CEI South filed its compliance extension requests with the EPA for the Brown Plant on November 25, 2020, and the Culley Plant on November 24, 2020. However, as of the filing date of her testimony, she noted the EPA's Part A Implementation website states CEI South's applications for Brown and Culley are still undergoing completeness reviews. She testified that until the EPA finalizes its review of CEI South's extension request, there is no certainty CEI South's plan to construct the ponds will comply with the CCR Part A Reconsideration Rule. She asserted that the possibility that the EPA will order CEI South to take other actions to meet these obligations makes a Commission approval of these projects too speculative, even though the deadline is approaching.

Regarding the project's cost estimates, Ms. Armstrong testified that CEI South has not provided reasonably accurate cost estimates for the Brown and Culley 2 CCR-Compliant ponds, nor has it accounted for the associated closure costs in its estimates. She indicated the new Brown pond could be completed by July 1, 2023, at an estimate of $13 million with ongoing O&M costs at $250,000, and the Culley pond could be completed by March 1, 2023, at a cost of $6 million with ongoing O&M costs at $100,000. She acknowledged CEI South's claims the new Culley pond could be used to hold Culley 3's Flue Gas Desulfurization (FGD) wastewater in the event the wastewater treatment facility approved in Cause No. 45052 is delayed. She emphasized that the estimates of both ponds are Class 5 estimates, which, according to the Association for the Advancement of Cost Engineering ("AACE"), is a conceptual cost estimate with an accuracy range of -20% to -50% on the low end and +30% to +100% on the high end. She therefore concluded that even absent additional EPA approval-related changes, CEI South's project cost estimates are so imprecise that they could double.

Ms. Armstrong emphasized the importance of a utility providing accurate cost estimates at the time it first seeks project approval from the Commission. She noted that cost deviations from the final project amount could change the reasonableness of selecting that resource or compliance option to meet customers' needs, as CEI South may forego another option that would have possibly provided greater customer benefits. She testified that once a project is approved, it is difficult to change course and select a better option. She explained that when a utility seeks subsequent approval regarding additional investment associated with a project, the issue becomes the incremental investment's reasonableness instead of the entire project's reasonableness and rejecting cost increases becomes increasingly difficult. She provided several past incidents of utility projects greatly exceeding their original estimates and indicated that utilities defended these significant cost increases by maintaining they were due to unforeseen or uncontrollable events such as increases in material prices. She countered that in her experience reviewing these projects, these cost increases should have been expected due to the utility providing conceptual, highly-variable Class 5 estimates at the time it initially sought a CPCN for the projects. She asserted that because of their inherent unreliability, Class 5 estimates cannot be used to establish that the costs represent the most reasonable alternative.

Ms. Armstrong further noted that CEI South has not included the costs to close the new CCR ponds in its project estimate for the Pond Compliance Project. She stressed the importance of considering closure costs when deciding to construct a new CCR pond, as the CCR Rule has strict requirements on how CCR surface impoundments must be closed. She explained that if the CCR impoundment is closed in place, it must have a final cover system that minimizes infiltration in compliance with the specific standards set forth in the rule. CCR units closed in place are also subjected to post-closure care requirements for at least 30 years after closure of the CCR unit is complete. She added that if a CCR impoundment is closed through removing CCR material, the CCR impoundment owner or operator must ensure any areas affected by releases from the CCR unit are removed and groundwater monitoring concentrations do not exceed groundwater protection standards. She indicated the costs of these closure requirements and post-closure care activities are significant and have the potential to impact the economic analysis of choosing to construct the CCR pond. She noted that Indiana electric IOUs have spent, or will be spending, hundreds of millions of dollars closing and remediating their ash ponds. She acknowledged that while the closure costs associated with the proposed Brown and Culley 2 ponds will be less than the costs associated with closing larger and older unlined ponds, these closure costs could be significant enough to shift the results of the economic analysis to construct the ponds and keep operating Brown 1 and 2 and Culley 2. She added that the environmental liability of a new pond carries unknown risks of additional remediation costs if the unit were to be compromised in any way that releases material from the pond.

Regarding CEI South's support to continue operating Brown Units 1 and 2 and Culley Unit 2 until October 2023, Ms. Armstrong showed that CEI South did not evaluate any resource portfolio where Brown Units 1 and 2 and Culley Unit 2 were retired prior to 2023 in its 2020 IRP. She stated that the deadlines for triggering closure of a CCR impoundment are before 2023.

She explained that the CCR Part A Reconsideration Rule required all unlined CCR surface impoundments, CCR units showing groundwater exceedances for multiple constituents, and CCR units failing the aquifer location restriction to cease receiving CCR by April 11, 2021, unless the source is seeking a compliance extension. She stated that the original 2015 CCR Rule required CCR impoundments showing groundwater exceedances or failing the aquifer location restriction to cease placing CCR and non-CCR waste streams in the impoundment by no later than April 2018 or April 2019, respectively. She added that in the 2018 Phase 1, Part 1 Amendments to the 2015 CCR Rule, the EPA extended the date for ceasing placement of CCR and non-CCR waste streams in surface impoundments to October 31, 2020, for CCR impoundments failing to meet the aquifer location restriction or impacting groundwater in excess of groundwater protection standards. She explained that without the ability to sluice, store, or dispose of CCR waste streams in the ash ponds, Brown Units 1 and 2 and Culley Unit 2 cannot operate. She asserted that an alternative compliance option would have been to stop generating CCR and retire Brown Units 1 and 2 and Culley Unit 2 by the April 11, 2021, deadline, which would have avoided the requirement for CCR-compliant ponds. She noted that CEI South can still revise its site-specific alternative deadline applications and avoid constructing the CCR-compliant ponds if it immediately retires the coal-fired generating units.

She cited I.C. § 8-1-8.4-6(b)(1)(D), which requires a utility to provide alternative plans demonstrating the proposed compliance plan is reasonable and necessary. She argued that without an economic analysis comparing the costs of 2021 retirement dates for Brown Units 1 and 2 and Culley Unit 2 with the costs of continuing to operate these units until 2023, it is not possible to determine the reasonableness of CEI South's request for the new ponds. She criticized CEI South for presuming the only pathway to compliance is to rely on its own generation. She indicated that if it is possible to replace Brown Units 1 and 2 over the short term with energy and capacity purchases, CEI South should explore that option.

Ms. Armstrong described the OUCC's review of CEI South's (Vectren's) 2020 IRP and agreed that the OUCC recognized that changes to the CCR and ELG Rules made during the Trump Administration were unlikely to extend the lives of Brown Units 1 and 2 and Culley Unit 2 as coal-fired units past 2023. She noted the 2020 IRP was not clear regarding how CEI South would be able to operate Brown Units 1 and 2 in compliance with the CCR Rule when the deadline for ceasing to send CCR to the Brown Ash Pond was October 31, 2020. She explained the OUCC participated in a teleconference with CEI South's environmental staff on September 9, 2020, to clarify how CEI South intended to comply with the CCR Rule after the cessation deadline. She stated that CEI South's environmental staff indicated they were evaluating the possibility of constructing the CCR-compliant pond, but she said the OUCC did not know the complete details of CEI South's compliance plan until CEI South filed its request in this case. She explained that the OUCC usually cannot obtain the level of detail during the IRP review process that it receives in CPCN cases and the agency is limited to specific details and costs the utility provides during the IRP process. She indicated that the OUCC was unaware these ponds would be used for holding CCR for only three months at Brown and six months at Culley prior to the October 2023 cessation/retirement date.

She reiterated the Class 5 estimates CEI South provided could increase by 30%-100%, and indicated that, based on this range, the final costs could be as high as $17.056 million to $26.240 million for the Brown Pond and $7.748 million to $11.92 million for the Culley 2 Pond. She pointed to the low capacity prices observed in MISO Zone 6 in recent years and reasoned significant potential cost increases in the Pond Compliance Project could impact the economics of constructing the new ponds.

She stated it was premature to determine whether CEI South should recover the Culley and Brown pond development costs while CEI South awaits the EPA's decision for extension. She asserted that CEI South should have revealed its full CCR compliance strategy for the Brown and Culley Plants prior to this filing. While Ms. Armstrong acknowledged the CCR Rule was amended several times since the original rule was finalized in 2015 (due to litigation and changes made during the previous Administration), she stated that it has been clear for some time CEI South would need to eventually stop sending waste to the existing ponds and close them. She noted that, except for Indiana Michigan Power Company, all other IOUs presented CCR Compliance Plans for their existing facilities to continue operation in the 2016-2018 timeframe. She testified that Duke Energy Indiana ("DEI"), Indianapolis Power & Light ("IPL"), and Northern Indiana Public Service Company ("NIPSCO") recognized their facilities were unlikely to meet the structural stability requirements or aquifer location restrictions by the original CCR Rule's rapid compliance deadlines, and that any available compliance options would take longer than two years to implement. She concluded that if CEI South failed to plan for alternative compliance options and quickly respond to CCR Rule changes, the OUCC would not support recovery of pond development costs.

While the Part A Reconsideration Rule significantly changed the Alternative Closure Requirements set forth in 40 C.F.R. §257.103 from the original 2015 Rule, Ms. Armstrong noted ambiguity in the 2015 CCR as to a unit's ability to qualify for the date-certain boiler cessation provisions without having to make additional investments in disposal capacity. She explained that the original Alternative Closure Requirements allowed a source to continue operating past the cessation deadline as long as: 1) the operator could show there was no alternative disposal capacity and 2) the generating unit and the ash pond were closed by 2028 (for ash ponds 40 acres or greater). However, she noted the operator was required to make efforts to obtain alternative disposal capacity, and increases in operating costs or the inconvenience of obtaining such disposal capacity were not sufficient to support the "no alternative disposal capacity" qualification. She testified that in the cases she evaluated and testified in regarding utility compliance plans in the 2016-2017 timeframe, other Indiana utilities were reluctant to make use of the Alternative Closure

Requirements, as they were not certain if the costs to continue to obtain or develop additional capacity would result in actual cost savings.

She recommended denial of the Pond Compliance Project due to CEI South's inadequate evidence supporting the decision to continue operating Brown Units 1 and 2 and Culley Unit 2 until October 2023, lack of EPA approval for an extension to continue operating the CCR ponds, and CEI South's failure to provide reasonably accurate cost estimates for the ponds or account for associated closure costs of the new ponds. She provided an alternate recommendation that CEI South shareholders be responsible for fifty percent of the costs if the Commission approves the Pond Compliance Projects, asserting that CEI South should assume some of the costs because it has unreasonably increased the risk to its customers and failed to consider cost effective alternatives.

Next, Ms. Armstrong described the Dry Ash Compliance Project, which involves constructing a silo to accept dry fly ash from CEI South's coal-fired generating units and a barge loading facility to load ash on barges to send downriver to CEI South's ash customer. She noted that CEI South estimates the Dry Ash Compliance Project will cost $12 million, which is a Class 3 estimate. She indicated that due to the Brown Ash Closure Project converting the current ash barge loading facility to handled ponded ash, CEI South can no longer transport or load dry fly ash on barges. She explained that CEI South is currently either trucking fly ash to the CEI South ash customer in Missouri or to a coal mine for beneficial reuse or disposal. She highlighted that depositing fly ash in coal mines could be impacted by future environmental rule changes, weather-related restrictions, and mine bankruptcy. She indicated that the other options CEI South considered for future fly ash disposal were either not possible, more expensive, or riskier to implement over a longer period. She agreed that CEI South considered multiple options for continued dry fly ash disposal. Although she noted the Dry Fly Ash Compliance Project was not the least cost option CEI South considered, she supported approval of the Dry Ash Compliance Project because it does not carry the same risks of future availability and environmental liability that the coal mine and landfill disposal options present.

Ms. Armstrong discussed CEI South's environmental assumptions supporting its decision to retire Brown Units 1 and 2. She stated CEI South assumed costs for environmental equipment necessary to comply with the CCR Rule and the Electric Steam Generation Effluent Limitation Guidelines ("ELGs") beyond 2023 are consistent with other Indiana electric IOU's compliance costs. She noted CEI South's concerns that the current Flue Gas Desulfurization systems ("FGDs") installed on Brown Units 1 and 2 would need to be replaced to continue operating past 2024. She indicated that new FGDs will cost hundreds of millions of dollars and create additional wastewater treatment and waste disposal issues for the plant. She also noted that CEI South assumed compliance costs for the Affordable Clean Energy ("ACE") Rule were no longer applicable as the rule had been vacated. She noted ACE Rule costs were not significant for Brown Units 1 and 2 and indicated compliance with the CCR and ELG rules and expected FGD replacements were driving the retirement decision for Brown Units 1 and 2.

She testified to the environmental benefits of natural gas generation, noting that natural gas emits far less sulfur dioxide ("SO_2"), nitrogen oxide ("NOx"), particulate matter, and CO_2 and generates significantly less quantities of waste and wastewater than coal-fired generation. She added that constructing the combustion turbines at the Brown Plant at the same time it retires

Brown Units 1 and 2 would allow CEI South to take advantage of emission netting when applying for the Brown CTs' air permits. She explained that emissions netting would allow the CTs to avoid Prevention of Significant Deterioration ("PSD") applicability, which results in a more complicated permitting process that can lead to additional operating limits for the units. She indicated that converting Brown Units 1 and 2 to operate on natural gas could also qualify for emissions netting and that the air permits for gas conversion would be the same as the permits necessary to construct the Brown CTs with the same timelines for issuance.

iv. Kaleb G. Lantrip, Utility Analyst, Electric Division (Pub. Ex. 4).

Kaleb G. Lantrip, Utility Analyst in the OUCC's Electric Division, testified about CEI South's proposed accounting and ratemaking treatment. Ultimately, he recommended the Commission deny CEI South's requested accounting and ratemaking recovery associated with its proposed CT projects, consistent with Witness Alvarez and Boerger's recommendations to deny CEI South's CPCN on the generation assets. Mr. Lantrip also recommended denial of Petitioner's request that the Commission grant recovery, even in denial of the CPCN, of $12 million in study/pre-work costs involved in planning for the CT projects, especially CEI South's inclusion of $5 million in IRP-related costs.

Mr. Lantrip recommended the Commission approve CEI South's proposal to use its Environmental Cost Adjustment ("ECA") rider's accounting and ratemaking treatment, but only on the Dry Fly Ash Recycle Project, consistent with Ms. Armstrong's recommendations on reviewing CEI South's proposed environmental projects.

Specific to CEI South's CT project ratemaking proposals, Mr. Lantrip discussed the Petitioner's proposed ratemaking deferral of PISCC and depreciation expenses from the time the CT Projects are placed in-service to the time that those costs are included and approved in a general rate case proceeding. While not supporting CEI South's proposal, Mr. Lantrip did not take issue with Petitioner's proposed accounting treatment on the CT Projects, or the use of a 30-year useful life for depreciation purposes.

Mr. Lantrip discussed how CEI South's ECA mechanism currently works, including recovery of 80% of costs through the ECA revenue requirement filings and deferral of 20% for future recovery, as well as CEI South's authority for Construction Work in Progress ("CWIP") and post-in-service carrying cost treatment of plant investment. Furthermore, CEI South proposed recognizing retired assets as an offset to gross plant balances in calculating the depreciation expense collected in the rider. Mr. Lantrip testified that he agrees in general with this recognition of retired assets effect on reducing gross plant. In conclusion, Mr. Lantrip noted that Petitioner is not requesting cost recovery in this filing, but did include an illustrative example schedule of what the ECA revenue requirement might resemble if the compliance project was approved by the Commission.

Mr. Lantrip completed his testimony by analyzing Petitioner's request to recover the CT projects' planning costs. He particularly objected to the request that CEI South should be permitted to defer the approximately $12 million in costs, even in the event that the CT CPCN's are not approved by the Commission, for later inclusion in a general rate case or alternative generation project. Pub. Ex. 4 at 9-10. In response to discovery, CEI South broke down the major parts of the $12 million, $2 million of which was due to CT projects' direct planning costs from 2020 to mid-

2021, and $5 million of which was from the generation asset planning cost pool which was established as part of CEI South's most recent IRP process. Mr. Lantrip's recommendation was based on IRP-related costs being a non-recurring cost of doing business as a utility, and that CEI South had previously expensed its planning costs when its Cause No. 45052 generation CPCN had been rejected in 2019. He stated there is no Commission precedent for allowing the separate recovery of IRP planning costs. *Id*. at 10.

C. Intervenor Citizens Action Coalition of Indiana.

i. Kerwin L. Olson, Executive Director, CAC. Kerwin L. Olson, Executive Director of Citizens Action Coalition of Indiana, provided testimony focused on the unaffordability of CEI South's electric rates and on the Field Hearing held to receive public input on CEI South's proposal. Beginning with unaffordability, Mr. Olson highlighted the fact that CEI South's rates are the highest in the State and among the highest in the region and country:

- Over the last twelve years, CEI South has had the highest bills in the State for a residential customer using 1,000 kWh per month among (1) all investor owned electric utilities and (2) all jurisdictional electric utilities. CAC Ex. 1 at 5.
- The Commission's own 2021 Residential Bill Survey shows CEI South maintained the highest electricity rates in the State over the last ten years. CAC Ex. 1 at 5–6.
- According to data from the United States Energy Information Administration, CEI South's average electricity bill in 2020 far exceeded the average bill in Indiana and the United States, as well as in the neighboring state of Illinois, Kentucky, Michigan, Ohio, and Wisconsin. CAC Ex. 1 at 6.

In light of the high costs of CEI South's monopoly electric service, Mr. Olson urged the Commission to prioritize customer protection and minimizing the risk of even higher future rates. CAC Ex. 1 at 8. He continued to emphasize that CEI South's service territory includes Evansville and Vanderburgh County—areas experiencing higher poverty levels and lower household incomes than Indiana's statewide averages. CAC Ex. 1 at 8–9. He emphasized the importance of considering the effect of rate increases on customers. CAC Ex. 1 at 9.

Additionally, Mr. Olson relayed his experience at the Field Hearing held in October 2021 in Evansville, where Hoosiers shared their reactions to CEI South's proposal:

> The customers that spoke included grandparents, parents, veterans, an IT professional, a financial advisor, a lawyer, a schoolteacher, a college professor, a township trustee, and many concerned citizens. The voices spoke in unison and asked the Commission to reject CenterPoint's plan. No one spoke in favor.

CAC Ex. 1 at 10. Mr. Olson provided a transcript of the Field Hearing as evidence, reflecting the voices of the ratepaying public: "These voices represent a party who has a substantial interest in this case—a party whose interests should be balanced with those of the utility, the large customers, and other intervenors in this proceeding, all of whom have an interest in achieving a fair and balanced outcome." CAC Ex. 1 at 11.

ii. Anna Sommer, Principal at Energy Futures Group. Anna Sommer, Principal at Energy Futures Group, brings nearly 20 years of experience in electric utility regulation and related fields, including particular expertise in integrated resource planning and related planning exercises. CAC Ex. 2 at 2. Since 2015, Ms. Sommer and her team, on behalf of CAC, have reviewed and provided comment on the integrated resource plans of all five investor-owned Indiana electric utilities, including CEI South. CAC Ex. 2 at 4.

Ms. Sommer offered CAC's earlier comments in CEI South's IRP, with limited corrections based on new disclosures from CEI South. CAC Ex. 2 at 8. Responding to claims by CEI South Witness Bacalao, Ms. Sommer clarified that the Company's scorecard was not vetted by stakeholders and does not address critical comments on the methodology used to develop the scorecard and the manner in which it was presented. CAC Ex. 2 at 13.

Ms. Sommer expressed concern about the lack of transparency in CEI South's modeling. Although CAC expected to license Aurora for the purpose of this case, CEI South refused to disclose the entirety of the modeling files claimed to support its proposed resource choice. Instead, CEI South maintained that computational data scripts used by its consultant, Siemens, to write information into the model and/or modify results as the model performs its optimization, could not be disclosed—not even under the protection of non-disclosure agreements. CAC Ex. 2 at 14–15. As Ms. Sommer explains, CEI South's refusal to disclose its modeling files prevented independent review and evaluation, leaving the parties and the Commission unable to verify fully that modeling was conducted correctly and as represented. CAC Ex 2 at 17.

Although the parties were not able to fully review the modeling, Ms. Sommer testified that the modeling files CEI South was willing to disclose included a number of flaws. Among them:

1. CEI South used an artificially low capacity value for solar resources;
2. CEI South modified a solar RFP bid to limit its selection;
3. CEI South restricted the model from selecting generic solar, wind, and battery storage resources until after 2025, thereby only allowing thermal resources to be selected in 2024;
4. CEI South inappropriately shifted the capital cost projections for new solar, wind, and battery storage resources;
5. CEI South assumed unreasonable cost savings for building a second turbine in 2025;
6. CEI South relied on a 2019 industrial sales forecast that cannot be externally validated, does not account for pandemic impacts, and so far, overstates actual industrial sales;
7. CEI South used limited and unreasonable assumptions to model demand response resources; and
8. CEI South improperly evaluated capital costs in its stochastic modeling.

Because CEI South would not provide parties with all its modeling input files, Ms. Sommer was unable to independently rerun the model with corrections for these flaws. Instead, Ms. Sommer was only able to work through a Siemens employee who, based on an agreement between the parties, would receive certain input changes from Ms. Sommer, rerun the model under those changed inputs, and provide results. CAC Ex. 2 at 15–16.

Under that process, Ms. Sommer provided corrected input assumptions to Siemens to be applied to CEI South's High Tech and Renewables by 2030 cases. CAC Ex. 2 at 28. Ms. Sommer summarized the results of both deterministic runs: neither optimization resulted in selection of new gas generation; the High Tech case favored more demand response and solar, achieving a lower

PVRR; and the Renewables by 2030 case favored more solar, storage, and wind resources at nearly the same PVRR. CAC Ex. 2 at 28–30. Ms. Sommer observed that these modeling runs show the cost-effectiveness of retiring coal units and replacing that capacity with a combination of demand response, solar, wind, and storage. CAC Ex. 2 at 30.

Via supplemental testimony, Ms. Sommer explained, after weeks of working on further stochastic modeling together, that the Company's contractor, Siemens, changed course and refused to provide the results of CAC's stochastic modeling. CAC Ex. 4 at 1, 5–7. As a result, Ms. Sommer's supplemental testimony was limited to review of CEI South's stochastic modeling and reporting what she would have expected additional stochastic modeling to show. She critiqued CEI South's use of stochastic modeling to test capital costs for certain resources, noting that stochastics are used to test random variables, but capital costs of new resources do not randomly occur. CAC Ex. 4 at 2. Ms. Sommer continued to explain that CEI South only considered a change in capital costs for a solar PPA resource, and even with a 30% increase, that resource continued to be economically optimal. CAC Ex. 4 at 3. Ms. Sommer also noted use of summer-peaking gas forecasts in stochastic modeling was inconsistent with the winter-peaking forecast used in deterministic modeling and unrealistic—Henry Hub prices historically have been winter-peaking. CAC Ex. 4 at 4–5.

Ms. Sommer also testified that CEI South overstates the diversity and risk benefits of its proposed combustion turbines. CAC Ex. 2 at 44–46. She cautioned that CEI South's proposal lessens its fuel diversity, leaves no off-ramps to adjust based on changes in the coming years, and does not provide a good hedge against carbon regulation. CAC Ex. 2 at 46–47. Ms. Sommer noted that other resources are capable of providing the same—or better—quick start and ramping capabilities, particularly battery storage. CAC Ex. 2 at 47–48. Using the 2019 Polar Vortex to illustrate, Ms. Sommer noted that CEI South overstates the likelihood that gas resources will provide an effective physical hedge against high energy prices given their sensitivity to market conditions. CAC Ex. 2 at 50–52. Ms. Sommer also responded to claims from Witness Bacalao about potential for the proposed CTs to provide a capacity hedge, noting the risk of lower capacity market revenues than forecasted by the Company. CAC Ex. 2 at 54–58. Ms. Sommer also noted the potential for continued increases in key commodity indices, presenting risks of higher costs for the proposed new CTs. CAC Ex. 2 at 58–64.

Concerning the new pipeline lateral that CEI South claims would be needed to serve the proposed combustion turbines, Ms. Sommer observed that it appeared to be nearly the same as the one proposed in Cause No. 45052 to serve the then-proposed 850 MW combined cycle plant. CAC Ex. 2 at 6. Ms. Sommer explained that the combustion turbines, however, could not possibly use the full capacity of such a lateral; the proposed new lateral is capable of transporting nearly double the amount of gas that two F class combustion turbines could use at full burn. CAC Ex. 2 at 37–39. Ms. Sommer noted that CEI South did not appear to explore alternative options for gas transportation service to the proposed combustion turbines. CAC Ex. 2 at 33–34. Ms. Sommer concludes that CEI South has not provided sufficient evidence documenting any consideration of alternatives or confirming the requirements of the proposed combustion turbines. CAC Ex. 2 at 34.

iii. Joshua Keeling, Director, Cadeo Group. Mr. Josh Keeling is the Director at the Cadeo Group, where he leads the Distributed Energy Resources and Electrification team. He is an expert in demand-side management and integration of distributed energy resources. Upon reviewing CEI South's proposal to construct two new gas combustion turbines, Mr. Keeling found CEI South's 2019-2020 IRP analysis and all-source RFP results do not sufficiently account for the contribution that demand response resources could make to meeting the need for firm peaking capacity. CAC Ex. 3 at 9. In its resource optimization modeling, CEI South did not model any economic dispatch of demand response resources, did not allow for selection of resources beyond those already in their program portfolio, and did not incorporate a bid provided in response to the all-source RFP for 50 MW of demand response. CAC Ex. 3 at 26–27. CEI South further did not model or otherwise explore potential for dynamic rates (e.g., time of use, critical peak pricing, and/or peak time rebates). CAC Ex. 3 at 26. He also noted that CEI South's Demand-Side Management potential study, conducted in 2019, inexplicably excluded industrial customers and commercial opt-outs representing half of CEI South's load, and a number of cost-effective programs identified by the potential study have not been pursued. CAC Ex. 3 at 9–10. As a result, Mr. Keeling explained that demand response was not truly integrated in the planning process, and there was no exploration of how demand response could further contribute to meeting capacity needs. CAC Ex. 3 at 37.

Mr. Keeling also provided modeling inputs to CAC Witness Sommer that more accurately characterize demand response as a dispatchable and selectable resource in the model. CAC Ex. 3 at 28–30. When demand response resources were offered as dispatchable and selectable resources, the CEI South's model selected 250 MW of available potential. CAC Ex. 3 at 30. Mr. Keeling noted that these results show the cost-effective but untapped potential, and concluded that at least 200 MW of additional demand response could be achieved in a 5 to 7 year timeframe. CAC Ex. 3 at 41. Mr. Keeling further recommended adjustments to CEI South's IC and IO Riders to bring them in line with best practices, including allowing aggregation, improving notification periods, bettering program options for commercial customers, and considering new time-varying rate options. CAC Ex. 3 at 35–36.

D. Intervenor Industrial Group.

i. Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. (Industrial Group Ex. 1). *[We adopt IG's summary of its own witness]*

E. Intervenor Sierra Club.

i. Michael Goggin, Vice President, Grid Strategies, LLC (SC Ex. 1).

Mr. Goggin is Vice President of Grid Strategies, LLC, and testified on behalf of Sierra Club. Mr. Goggin's testimony was based on his expertise in renewable energy and power system integration, including his prior roles directing the research and analysis team of the American Wind Energy Association, serving as a consultant to the U.S. Department of Energy, and as an elected member of the Standards, Planning, and Operating Committees of the North American Reliability Corporation (NERC). Mr. Goggin recommended denial of the requested CPCN. Mr. Goggin based that recommendation on analysis of CEI South's IRP and more recent cost estimates for renewable generation, capacity on the MISO grid, errors in CEI South's assessment of the capacity value of wind and solar resources, the benefits associated with battery storage that were not incorporated into CEI South's modeling, and risks associated with reliance on natural gas that CEI South did not acknowledge in its testimony or IRP. SC Ex. 1 at 2-3.

Upon reviewing CEI South's IRP, Mr. Goggin observed that CEI South's own analysis showed an all-renewables portfolio would be less expensive than the preferred portfolio that included the two proposed CTs in three out of five modeled scenarios and that the CTs would only be cost-effective if gas prices remained low and peak load increased. SC Ex. 1 at 5. Mr. Goggin observed that CEI South's own modeling predicted the two CTs would operate at zero or near-zero capacity factors for the next twenty years and thus presented significant stranded asset risk. SC Ex. 1 at 9-10. Mr. Goggin also concluded that CEI South's capacity price forecasts were unjustifiably high, as capacity auction prices in Zone 6 have ranged from $1.50-$10/MW-day for the last five annual auctions and Zone 6 had 4,600 MW in import capacity to spare in the most recent MISO capacity auction. SC Ex. 1 at 19. Mr. Goggin observed that increased interzone imports actually improve grid reliability and the capacity value of wind and solar resources. SC Ex. 1 at 23.

Mr. Goggin then considered alternatives to the proposed CTs that CEI South had rejected. First, Mr. Goggin found that CEI South dramatically understated the capacity value of the renewable resources included in its IRP. Specifically, Mr. Goggin rejected CEI South's projection that summer solar capacity would fall below 29% and winter solar capacity would fall below 7% by 2023, a projection based largely on unrealistic estimates of renewable saturation within the MISO grid. SC Ex. 1 at 24-25. Mr. Goggin testified that a more realistic estimate that incorporates the benefits of geographic diversity and synergistic effects of overlapping wind and solar generation predicts a much higher and more gradually declining ELCCs; for example, the MISO Transmission Expansion Plan modeling from 2019 assumes solar capacity accreditation in MISO remaining at 50% through 2023 then declining steadily to 30% in 2033. SC Ex. 1 at 30. Mr. Goggin also pointed that CEI South witness Dr. Bacalao erred in simply assuming that a three-hour battery would simply have an ELCC that is 75% of a four-hour battery. SC Ex. 1 at 40. Batteries, Mr. Goggin testified, are more flexible, faster-ramping, and precise than gas-fired units in responding to changes in power-system frequency and provide a hedge against higher gas prices, advantages that CEI South's modeling did not fully capture. SC Ex. 1 at 43-44. Selection of batteries rather than the proposed CTs would also avoid the significant stranded asset risk of gas-fired generation and associated pipeline construction as well the risk of correlated outages among gas generators that CEI South failed to account for in its analysis.

F. Intervenor Sunrise Coal.

i. <u>Emily S. Medine, Principal, Energy Ventures Analysis, Inc. (Sunrise Coal Ex. 1)</u>. Emily S. Medine, a principal with Energy Ventures Analysis, Inc., testified on behalf of Sunrise Coal, Inc. Ms. Medine has four decades of experience in energy and power markets. Sunrise Ex. 1, Attachment ESM-1. Ms. Medine recommended denial of the requested CPCN to construct two new Combustion Turbines (CTs). Ms. Medine raised the following issues with the CPCN:

(1) A new lateral gas supply pipeline must be installed under the Ohio River from Kentucky. FERC approval for that new line is contested and subject to an environmental impact statement, creating risks that approval will be denied or appealed. Sunrise Ex. 1, at 5-6.

(2) The proposed CTs represent a significant and long-term investment in new fossil fueled generation. The 2019/2020 IRP on which CEI South relies to justify that investment as economic fails to account for material changes in circumstances, including (a) changes in the energy and power markets after 2019/2020; (b) current and future supply chain delays on timely construction of new capacity; and (c) the effect of timely construction by other utilities on MISO capacity and energy prices. Sunrise Ex. 1 at 15-24. Ms. Medine noted that other utilities have revised previously announced generation transition plans in response to changes in the energy and power markets and identified several that have done so. Sunrise Coal Ex. 1 at 18-24.

(3) The 2019/2020 IRP failed to consider all available options for meeting energy and capacity requirements at reasonable prices. Sunrise Ex.1 at 7. Specifically, it failed to consider alternative CCR compliance strategies enabled by 2020 regulatory amendments that could allow continued operation of the AB Brown coal units until the 2026 to 2028 timeframe. Sunrise Ex. 1 at 7-11. Ms. Medine notes that that such an alternative is further explained in the testimonies of Sunrise witnesses Nasi and Sutton. Sunrise Ex. 1 at 6-8.

Ms. Medine also countered concerns expressed by CEI South witness Games concerning the financial strength of Sunrise or its parent company. Sunrise Ex. 1 at 9-10.

Ms. Medine also addressed concerns express by Mr. Games about the adverse effect of coal plant cycling on operation and maintenance expense by noting that CEI South had failed to use all means possible to improve the dispatch of its coal units by lowering the dispatch costs when feasible.

Ms. Medine also opined that CEI South's commitment to early closure of coal-fired generation at the AB Brown station could be motivated by the benefit such closure has on CEI South's earnings. Sunrise Ex. 1 at 8-9.

ii. <u>Michael J. Nasi, Partner, Jackson Walker L.L.P. (Sunrise Coal Ex. 2)</u>. Michael J. Nasi, a partner with the law firm of Jackson Walker LLP, testified on behalf of Sunrise Coal, Inc. Mr. Nasi has over 27 years of experience practicing before state and federal environmental law and energy agencies. He has provided testimony before multiple state legislatures on various aspects on environmental law, with particular emphasis on air, water, and waste regulations on the electric power industry. He serves as regulatory counsel to a number of state and federal coalitions primary focused on coal-fired power generation regulatory issues. Sunrise Ex. 2, Attachment MJN-1.

Mr. Nasi testified that CEI South's submission to USEPA pursuant to 40 CFR § 257.103(f)(1), seeking the extension of the use of the CCR surface impoundment at A.B. Brown, did not evaluate all reasonable alternatives, and was in fact designed to require the closure of A.B. Brown by no later than October 15, 2023. Mr. Nasi explained that CEI South evaluated eight alternatives, and that of those eight, CEI South eliminated seven alternatives due to its claim that they were infeasible and/or would go beyond October 15, 2023 to implement. The alternative that CEI South selected could be completed prior to October 15, 2023 but it was designed to capture a fraction of the CCR flows. Since it was not designed to capture the entire CCR flow, the operation of the coal-fired boilers at A.B. Brown would have to be ceased. Mr. Nasi testified that CEI South failed to evaluate a hybrid alternative that entailed the conversion of the fly ash handling system to dry handling, thus reducing the significant portion of the CCR wastestream, and construction of a slightly bigger pond to serve the remaining fraction of the CCR wastestream.

Mr. Nasi further testified that a filing with USEPA pursuant to 40 CFR § 257.103(f)(2) could extend the life of A.B. Brown beyond October 2023, since under that provision the coal fired boilers must cease operation and the surface impoundment must complete closure no later than October 17, 2028. In response to testimony by CEI South witness Retherford that a filing under § 257.103(f)(2) is not possible given that the closure plan had been approved (in Cause No. 45280) and that closure plan did not contemplate completion of closure by October 17, 2028, Mr. Nasi stated that, from a regulatory standpoint, nothing prevents the filing of an amended closure plan. On this issue, Mr. Nasi further testified that the regulations specifically allow a facility to change course and pursue an alternative closure under § 257.103(f)(2), even if a prior filing under § 257.103(f)(1) has been made. Accordingly, from a regulatory standpoint, CEI South can amend its closure plan, and then pursue a filing under § 257.103(f)(2), thereby potentially extending the life of the boilers at A.B. Brown beyond October 2023.

Mr. Nasi also countered concerns expressed by CEI South witness of the challenges of continued operations of the A.B. Brown plant and costs of over $150 million. Mr. Nasi testified that the $69.4 million price tag associated with the installation of a Wet Electrostatic Precipitator is speculative and should not have been included as a cost for continued operation of the A.B. Brown plant. Mr. Nasi further testified that the $39 million cost associated with the conversion to a dry ash handling system may not be necessary as CEI South never evaluated an option of not converting that system.

Finally, Mr. Nasi testified that a new gas supply pipeline must be installed under the Ohio River from Kentucky which would require FERC approval, and the preparation of an Environmental Impact Statement. Mr. Nasi testified that it would not be prudent to proceed with the combustion turbine project prior to the resolution of the matter before FERC.

iii. <u>Tommy L. Sutton, Engineering Manager, Sunrise Coal, LLC (Sunrise Coal Ex. 3)</u>. Tommy L. Sutton, Engineering Manager for Sunrise Coal, testified for Sunrise Coal. Mr. Sutton has over 40 years of experience working in coal industry engineering and management in Western Kentucky, Indiana, and Illinois. Mr. Sutton explained how reclaimed CCR can be and are being beneficially used in coal mining operations. Sunrise Ex. 3 at 1-6. Mr. Sutton testified that Sunrise currently beneficially uses CCR from the Culley and Warrick powerplants at two of Sunrise's coal mines and is in discussions with CEI South to beneficially use CCR at a third mine. *Id*. at 4-5. Mr. Sutton said that to his knowledge CEI South has never approached Sunrise to discuss whether Sunrise could beneficially use CCR from the AB Brown station. *Id*.at 5. Mr. Sutton also said that had any such inquiries come from CEI South, he would have been involved in responding. *Id*. Mr. Sutton also said that Sunrise would be interested in discussing beneficial use of CCR from the AB Brown station. *Id*. at 5-6.

In his supplemental testimony Mr. Sutton testified that he had received from CEI South and reviewed its analysis of the estimated amount and content of the CCR currently in the AB Brown ash pond. Sunrise Ex. 4, at 1. Mr. Sutton said the analysis revealed nothing that would prevent the CCR at AB Brown from being beneficially used in southern Indiana coal mines, including those operated by Sunrise. Mr. Sutton also testified that the estimated quantity of CCR in the AB Brown ash pond could be moved to southern Indiana mines by truck in as little as four years running only about 300 trucks 250 days a year, which is less than the number of trucks that Sunrise runs daily out of its Oaktown mines.

G. CEI South's Rebuttal Evidence. *[We adopt CEI South's summaries of its own witnesses, except where testimonial statements are written as factual]*

4. Commission Discussion and Findings.

A. CPCN for CTs and related relief

i. Introduction

This CPCN request is governed by I.C. ch. 8-1-8.5, which requires CEI South to meet its burden of proof on numerous statutory elements, and requires us to make several specific findings, before CEI South's CPCN request can be approved. Failure to prove even a single required statutory element, or our inability to make any required finding, is fatal.

As we explain in detail below, we deny CEI South's CPCN because there are several statutory elements as to which CEI South did not provide sufficient proof, and there are accordingly several required findings that we cannot make on the evidentiary record before us. Overall, we find it inappropriate to saddle ratepayers with a long-term asset that will be rarely used and will require significant pipeline infrastructure. Given the long-term uncertainty as to the MISO energy and capacity markets, carbon regulation, and the cost of storage resources, we believe the appropriate time horizon for consideration in this proceeding is 2026-27, when CEI South will be able to construct generation selected through its next IRP. Based on the evidence presented we conclude that a long-term investment in gas generation is unnecessary to meet the short-term risk of capacity shortfall CEI South has identified.

We are mindful of our regulatory role, and whenever possible, we avoid supplanting a utility management's decisions with our own. That said, with respect to CPCN requests for major capital cost projects such as CEI South proposes here with no viable off-ramps over the economic life of the plants (which may be two decades or more), our regulatory oversight is critical for the protection of customers. Specifically, we note that before the CPCN procedures outlined in I.C. ch. 8-1-8.5 were enacted in the 1980s, utility investors and management risked their own funds to construct generating stations, and only when complete did they petition this Commission for a determination the new facilities were used and useful. If the Commission disagreed the utility might be denied both recovery of and return on some or all of its investment. Accordingly, utilities were financially at risk if they misread the future when deciding about investments in major capital projects.

Generating stations, and pipelines for that matter, have useful lives lasting many decades. Thus, there will always exist a risk that the future need for a certain amount of generation or a certain kind of generation may be misestimated. This risk has been shifted from utilities to customers by I.C. ch. 8-1-8.5, which guarantees a return on investment to utilities if they obtain a CPCN before new generation is constructed. Notably, I.C. ch. 8-1-8.5 did not change the ratemaking paradigm under which a utility earns a return on investment based, in part, on the value of generating resources it owns. This creates an incentive for utilities to construct new generation rather than purchase capacity or energy, and thereby increase (in absolute terms) its rate base and return on equity. This combination of guaranteed recovery if a CPCN is granted and increased recovery for generation versus energy purchases can create a one-way ratchet favoring over-build, to ratepayers' detriment.

Given these realities, our regulatory responsibility requires us to carefully scrutinize CPCN requests, especially when, as here, we are considering a nearly complete replacement of a utility's generation portfolio. In order to protect customers from imprudent investment, we will hold utilities to their burden of proof to satisfy each element of the statute.

In Cause No. 45052, the Commission rejected a CPCN for then-Vectren's proposed 850 MW CCGT. *In re Petition of S. Ind. Gas & Elec. Co.*, Cause No. 45052, 2019 WL 6770066 (Ind. Util. Regul. Comm'n Apr. 24, 2019). In doing so, we observed that the "proposal seems to close most off ramps for the foreseeable future" by installing a high proportion of then-Vectren's total load in a single unit and fuel type. *Id*. * 27. We also highlighted "the risk that any such investment may become uneconomic over the long-term" in a "period of seemingly quickening technological change." *Id*. * 22. Adopting the principles outlined above, we observed that, "[b]ecause unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment." *Id*. We urged then-Vectren to "maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes" in their resource mix. Id. *27, *quoting* 2018 Statewide Analysis. And we cautioned then-Vectren that its proposals for new generation must include "off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources." *Id*. * 27. We find CEI South has again proposed an outsized generation build that lacks off-ramps and that creates considerable stranded asset risk.

CEI South is the smallest investor-owned electric utility in Indiana and for twelve years has had the highest monthly residential bills in our Annual Residential Bill Survey (with the exception of 2010, where Marshall County REMC did). CAC Ex. 1, p. 5. Notably, CEI South does not fare well in terms of residential customer satisfaction, continuing its decline from fourth from the bottom in 2020 to second from the bottom in 2021. CAC Ex. 8, JD Power 2020 and 2021 Electric Utility Residential Customer Satisfaction Studies.

The short-term capacity need set forth by CEI South does not justify the risk posed by the proposed CTs and pipeline. CEI South witness Bradford explained that CEIS has made capacity purchases to cover its MISO capacity requirements through the 2024/2025 MISO capacity planning year. *See* Pet. Ex. 11-R at 7, discussing CEI South's "capacity purchases in the five-year period (2023 - 2028) following the closure of AB. Brown." And CEIS witness Greenley explained that resources acquired under the next IRP could be online by mid-2027 - in time for the start of the 2027/2028 MISO capacity planning year. Pet. Ex. 1-R, pp. 8, l. 17 – 9, l. 14, concluding with "we would expect to place in service the ultimate replacement generation by mid-2027." Therefore, the immediate need for the CTs that CEIS seeks to address are capacity requirements from June 2025 through June 2027.

As we must, we are required to determine if CEI South's evidence satisfies the burden of proof required by the CPCN statute. We begin with the evidence failing to sufficiently demonstrate necessity, which is the threshold requirement for granting a Certificate of Public Convenience and *Necessity*. I.C. § 8-1-8.5-2. CEI South has not demonstrated that it is presently required by regulatory mandate or other strictures to construct the proposed CTs. We are also unable to find that CEI South adequately considered or appropriately rejected capacity purchases as an alternative means of meeting customer load. I.C. § 8-1-8.5-4(1). We must also consider under I.C. § 8-1-8.5-4(2) whether CEI South has other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources. CEI South's analyses show insufficient alternatives to allow us to approve the significant investment CEI South proposes in new CTs and the necessary infrastructure to support them.

In addition, I.C. § 8-1-8.5-5(b)(1) requires that we find CEI South's construction estimate of $323-351 million, plus approximately $546 million for transportation capacity on the required pipeline, to be a best estimate. The evidence does not support that finding; CEI South was not willing to commit to a specific cost given that their uncapped price increases are built into the contract. More importantly, the cost and risk of this proposal do not justify the expense. Even if we found the estimates to be reasonable, the cost-benefit analysis says that the costs are too high for a very meager return.[3]

Moving on, I.C. § 8-1-8.5-5(b)(2)(A) requires that we find that CEI South's proposal is consistent with our 2018 Statewide Analysis. However, as we explain below, CEI South's proposal appears contrary to our Analysis regarding resource and fuel diversity, or the maintenance of off-ramps and flexibility. In addition, it does not adhere to the finding that MISO is primarily responsible for defining resource adequacy and operational reliability requirements. In the alternative, I.C. § 8-1-8.5-5(b)(2)(B) requires a finding that CEI South's proposal is consistent with its own IRP. I.C. § 8-1-8.5-5(d). On the evidence before us, there are simply too many questions and doubts concerning whether CEI South's IRP, and the modeling supporting it, fairly considered all resource alternatives. There is ample reason to be concerned that the IRP's design and screening preordained heavy gas and a capital-intensive outcome.

Ultimately, I.C. § 8-1-8.5-5(b)(3) requires that we find that public convenience and necessity support the projects, necessarily implicating the public interest. Here again, the evidence is insufficient to find that CEI South's proposal is in the public interest. For example, it is clear that CEI South's significant near future costs will burden its electric customers independent of our decision in this case. The potential bill impact of the capital cost of the proposed CTs and a new gas pipeline to feed the CTs, plus the annual fixed cost to operate and maintain that gas line, is enormous. When considering the public interest this case, we cannot ignore the significant impact on customers and the economy of southern Indiana. This is a stark risk to CEI South's customers, based on a thirty-year bet on natural gas facilities that have capacity factors that never make it into

[3] Because CEI South's proposed CTs are more than 80 MW, I.C. § 8-1-8.5-5(e) requires that we find that CEI South's cost estimates for engineering, procurement, and construction are the result of competitive bidding, unless it is commercially impractical, and that we consider both reliability and solicitation of bids from others to supply electricity. We discuss this further below.

double digits. All these factors weigh against approving CEI South's CPCN request. Our inability to make the required finding for any one of the above requires denial of CEI South's CPCN request.

ii. I.C. § 8-1-8.5-2 (necessity for certification).

CEI South's claims that its request for the two CTs is consistent with its IRP. However, at the hearing, CEI South Vice President Power Generation Operations Wayne Games repeatedly stated that he disagreed with key findings of the IRP with regard to the two CTs. The IRP concluded that the two CTs would run at an annual capacity factor of about 1-3% (and in many years, the second CT operates for zero hours), as backup generation used only at critical times and turned on a few times a year. IG Ex. 1 at 3; SC Ex. 1 at 8. Mr. Games disagreed with that conclusion and stated that he believed that the CTs would run far more often and be turned on multiple times per day. Mr. Games' testimony at the hearing raises doubts about whether CEI South's projections for the CTs are consistent with its IRP.

Regardless, consistency by itself does not mean automatic Commission approval. The Commission must find that all elements of the statute are met. One of the required elements to support a CPCN is expressed in its title – a utility must show that there is a necessity for the requested project. In this case, CEI South claims a necessity for two CTs approximating 460 MW that is not supported by the evidence. *In re NIPSCO*, Cause No. 43396, 2008 WL 2434152 at *23 (Ind. Util. Regul. Comm'n May 28, 2008) ("Our threshold inquiry addresses whether NIPSCO has demonstrated a need for additional generating capacity in this proceeding.")

CEI South needs to consider alternatives to such a significant capacity build-out, including smaller unit additions, alternative environmental upgrades, the addition of renewables, and procurement of readily available conservation and load management (in particular, demand response resources that could be as simple as revising their current industrial tariff and educating customers on the availability and benefits of demand response). CEI South did not properly evaluate these alternatives in its 2019/2020 IRP. This is underscored by the fact that should we approve its request, CEI South would be well in excess of MISO's current required planning reserve margin of 8.7% until 2038. CAC Ex. 2, pp. 46-47. Should CEI South's old load forecast from 2019 that it relied on turn out to be too high, as past forecasts have been, CEI South will add unneeded excess capacity and an expensive pipeline at great cost to its ratepayers. We find that given the evidence, CEI South does not have the demand to justify this plant.

iii. Ind. Code §§ 8-1-8.5-4 and -5. In order to succeed on its CPCN request, CEI South's evidence must permit us to make all the required findings under I.C. §§ 8-1-8.5-4 and -5. As explained below, there are many such required findings that we cannot make on the evidentiary record before us.

a. *Ind. Code § 8-1-8.5-4(1) (current and potential arrangements with other electric utilities for interchange, pooling, purchase, or joint ownership).*

In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities." I.C. § 8-1-8.5-4(1). Three findings in this area are most-pertinent to our decision. “The statute does not limit the Commission’s discretion to weigh the importance of each alternative in determining the public interest.” *In re Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, 2002 WL 32089933 at *14 (Ind. Util. Regul. Comm’n Dec. 19, 2002).

First, CEI South has suggested that it would be too risky for CEI South to rely on MISO markets for any extended period of time to meet energy or capacity needs. Like other Indiana utilities, CEI South is an active participant in the MISO energy and capacity markets, and any inquiry under I.C. § 8-1-8.5-4(1) must begin with recognition of that fact. *See N. Ind. Pub. Serv. Co.*, Cause No. 43396, 2008 WL 2434152 at *25. CEI South customers pay for the cost of membership in MISO and benefit from such membership. Those benefits include increased reliability for CEI South customers. Unlike the Texas grid, for example, Indiana is not an electric-grid island. Indiana utilities can draw on resources across a broad region and can generate revenues by selling power to utilities in other states. CEI South continues to take a one-sided view of market risk, treating purchases from the market as inherently risky without acknowledging that over-building its generating capacity also creates risk for its ratepayers. In Cause No. 45052, we found that “Vectren South’s Strategist model limited the amount of capacity purchases that a given portfolio could make.” *Cause No. 45052*, 2019 WL 6770066 at *22. CEI South’s preferred portfolio in the 2019-2020 IRP relies on an even lower level of annual capacity purchases: 4 MW after 2024. Pet. Ex. 5 at 17. We find that CEI South has over-emphasized the risk of capacity purchases in this proceeding, at least in the near term.

Second, we find that CEI South’s choice of two gas CTs is not supported by a comparison to short-term capacity purchases, at least through planning year 2027/2028, when CEI South will have an opportunity to fully implement a preferred plan from its upcoming 2022-2023 IRP. Both CEI South’s actually executed short-term capacity purchases and its forecasted capacity prices are lower than the capacity cost of the proposed CTs. CEI South has failed to explain why the premium it proposes to pay for constructing generation immediately is outweighed by the risk of increased capacity prices beyond 2027/2028, or why that risk is not counterbalanced by the uncertainties associated with a rapidly changing grid.

CEI South has already committed to capacity purchases, that in combination with CEI South’s other resources, are sufficient to meet its MISO resource adequacy requirements through the 2024/2025 MISO planning year. CEI South has also committed to some capacity purchases in the planning years 2025/2026, 2026/2027, and 2027/2028, although the level of these purchases is under half of the amount of capacity that CEI South has purchased in planning year 2024/2025 and about one quarter of the purchases in planning year 2023/2024. Pet. Ex. 11-R at 7, Table FSB-R1. Without the construction of the proposed CTs, these existing capacity contracts alone are not sufficient to meet CEI South’s projected resource adequacy requirements for these three planning years: 2025/2026, 2026/2027, and 2027/2028.

The prices of CEI South’s existing capacity purchases compare favorably to the IRP forecasted capacity prices. CEI South Witness Bradford testified that the IRP reliably estimated forecasted capacity pricing by comparing the IRP’s forecast of future years’ capacity prices to the actual bilateral purchases recently made by the Company for planning years 2023/2024, 2024/2025, 2025/2026, 2026/2027, and 2027/2028. Pet. Ex. 11-R at 7, Table FSB-R1. We note that the IRP capacity forecast is at least at the same order of magnitude as the Company’s experience of actual bilateral market prices for these years. But we observe also that for every future planning year, the actual purchase price CEI South has paid is lower than the forecasted price, and the actual purchase prices do not reflect an upward trend in pricing, unlike the Company's IRP forecasted prices. The actual prices paid in those years are significantly lower; the gap between forecasted prices and actual contracted prices also widens in the latter years.

More to the point, these *actual* capacity prices CEI South has paid for the next six years are lower than the gross capacity cost (*i.e.* without taking into account any energy revenue) of the two proposed CTs.[4] In discovery, CEI South was asked for the MW-day capacity cost of the proposed CTs and declined to produce it. We, though, calculated a rough estimate of the cost at $385.50 per MW-Day, which includes the transportation cost of the pipeline.[5] Further, the maximum capacity price that CEI South could pay under MISO's current annual capacity market construct, the Planning Resource Auction ("PRA"), is capped[6] by the MISO administratively determined Cost of New Energy ("CONE"), which equates to $244.16 per MW-day, as of 2021-2022. CAC Ex. 7 at 1. CEI South has capacity available to it for short-term purchase that is far cheaper than CONE, but we observe that its risk of exposure to the market is also somewhat limited by this cap.

Should CEI South choose to meet less than all of its Planning Reserve Margin Requirement (as set by MISO) via a Fixed Resource Adequacy Plan (which uses capacity the Company owns or controls) – and thus choose to satisfy its residual annual capacity need through MISO's PRA – CEI South would be exposed to PRA clearing prices, which, for Local Resource Zone 6 where CEI South is located, have historically been far lower than the prices represented by bilateral capacity purchases. The past eight PRAs (starting with 2014-2015) have seen clearing prices for Zone 6 of $16.75, $3.48, $72.00, $1.50, $10.00, $2.99, $5.00, and $5.00 per MW-day. CAC Ex. 7; SC Ex. 1, Att. MG-9 at 9. Additionally, FERC will likely decide this year on MISO's proposed

[4] As CEI South's own evidence shows the projected capacity factor of the proposed CTs will never exceed 5% each. IG Ex. 1 at 3; SC Ex. 1 at 8. Any energy revenues associated with the units are therefore likely to be minimal.

[5] The annualized capital cost and ongoing fixed operations and maintenance costs of the CTs, plus the annual fixed contractual cost of the pipeline is. $385.50/MW-day. This figure is derived per the following calculation of the annualized capital cost of the CTs plus the ongoing fixed costs of the CTs and pipeline ($351,400,000*7.71%/(1-(1+7.71%)^-30)+$27,300,000+$2,725,000)/428.9 MW/365.24 days = $385.50/MW-day, where $351,400,000 is the high-range capital cost of two CTs per Pet. Ex. 2-R at page 33, 7.71% is CEIS's weighted average cost of capital, 30 years is the proposed book lifetime of two CTs per page 27 of Pet. Ex. 5, Att. MAR-2, $27,300,000 is the annual fixed cost of the pipeline contract, and $2,725,000 is the annual fixed operations and maintenance cost of the two CTs, 428.9 MW is the MISO-accredited capacity of the two CTs, and 365.24 is the number of days in a year. While the pipeline cost for years 21-30 of the CTs' operation is unknown because it is outside of the 20-year pipeline contract, even if the cost were drastically lower than under the 20-year contract it would not meaningfully reduce the discounted annual average total cost of the CTs and pipeline below $385.50/MW-day, as any pipeline cost savings realized in years 21-30 will have little net present value due to the 7.71% discount rate. We take administrative notice of this calculation, which relies on inputs that are in the record.

[6] MISO Tariff, Module E-1, § 69.A.7.1.c.x. This provision has been proposed by MISO to be adjusted for a new seasonal PRA construct, in the pending FERC Docket No. ER22-495.

change to a seasonal capacity market construct in Docket No. ER22-495. Should the nature of the MISO capacity market change as envisioned by MISO, it would be prudent for CEI South and this Commission to wait until the next IRP process to fully incorporate the implications of that change.

Third, we also observe that CEI South's choice of two CTs is not supported by an all-source requests for proposals ("RFP"). In its 2019-2020 IRP, CEI South issued an all-source RFP that purported to address this Commission's criticisms in Cause No. 45052 that its prior RFP was "unduly restrictive given the rapid changes in technology and costs being seen in the market, especially regarding renewable energy." *Cause No. 45052*, 2019 WL 6770066 at *23 – 24. In the RFP conducted with the 2019-2020 IRP, responses included numerous battery and combined solar and storage options. Tellingly, however, CEI South did not receive any bids for a combustion turbine. We appreciate that CEI South issued an all-source RFP during its 2019-2020 IRP, and continue to believe that such all-source solicitations are an IRP best practice. Consistent with our findings in Cause No. 45052, we find that CEI South failed to explain why it selected a technology for which it did not receive *any* competitive bids in its own RFP. In any event, unlike in other CPCN proceedings, we cannot base an approval here on a competitive solicitation.

In sum, we find that CEI South has not presented evidence sufficient to justify its decision to reject capacity market purchases as one alternative to its proposed construction of the proposed CTs to fulfill its resource adequacy obligations. The construction of two proposed CTs, with total capacity approaching half of CEI South's load, considering the long-term costs and risks for customers is, at a minimum, premature, given the availability of alternatives for meeting resource adequacy requirements that are lower cost and that entail less risk.

b. *Ind. Code § 8-1-8.5-4(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 also find the CPCN application for the CTs must be rejected as a result of our analysis under I.C. § 8-1-8.5-4(2). As we note in our discussion regarding whether CEI South provided a "best estimate," a failure to fully examine these options means that CEI South has not met the statutory requirements for the grant of a CPCN.

(1) *Refurbishment.*

In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. I.C. § 8-1-8.5-4(2). We agree with the OUCC and Sunrise that CEI South did not fully and properly consider options to extend the life, or refurbish, existing units as required by I.C. § 8-1-8.5-4(1).

Looking to I.C. § 8-1-8.5-4(2), we now consider the issue of refurbishment. As discussed by OUCC witnesses Dr. Boerger and Mr. Alvarez, the cost in the economic modeling provided by CEI South between conversion of the two A.B. Brown units and building the two new requested turbines is close. Pub. Ex. 1, p. 17, ll. 1-7. But "close" does not incorporate all the relevant factors, and the evidence showed that CEI South improperly weighted its analysis against refueling option by failing to consider shared savings and other cost reductions.

Specifically, CEI South argued that it needed the proposed CTs for capacity while also acknowledging that the proposed units would only operate for short periods of time, characterizing them as "peakers." CEI South's projected capacity factors for the two proposed turbines showed that the new units' capacity factor never went over six percent, and in fact were at zero for multiple years. Tr. B- 8 – B- 9; OUCC CX 1. Mr. Games attempted to disavow this projection (produced in discovery) as inaccurate but acknowledged that the information had been provided by the Company. Tr. B- 8, ll. 15-25. In contrast, CEI South's response to OUCC DR 5.7 (OUCC CX 2) showed that the refueled units would have higher capacity factors, a fact Mr. Games also tried to disavow. Tr. B-9, ll. 15-16. The refueled units' higher capacity factors were derived from CEI South's 2019 IRP, which was used to determine CEI South's preferred portfolio in this case. Tr. B –8, ll. 11-14. This is consistent with other Indiana utilities' experience with refurbished coal-to-gas units. CEI South acknowledged "that the refueled Harding Street are outliers operating more than normal when comparing capacity factors to other coal to gas conversion in the US and MISO." OUCC CX 11. Nonetheless, Mr. Games disagreed with the higher capacity factors contained in CEI South's own IRP for the Brown units.

We find CEI South's efforts to distinguish the AB Brown units from the Harding Street refurbishment unavailing. Mr. Games' rebuttal stated AES Indiana's refueled Harding Street units provided only voltage support. Pet. Ex. 2-R, p. 25; Tr. B- 32. But when questioned on cross-examination, Mr. Games admitted that the Harding St. units' "refueling [was] necessary to provide dynamic reactive power, system reliability, avoid transmission upgrades, supply dynamic voltage support, improve voltage support, and avoid potential load shedding events[.]" Tr. at B- 32, ll. 20-23. Mr. Games then admitted that the Harding St. units provided IPL with reliability – and "reliability is primary." Tr. B- 33, l. 14. And in one of CEI South's discovery responses regarding the Harding Street conversions, OUCC CX-11, CEI South referred to the Harding Street units as "outliers operating more than normal", thereby acknowledging that the units ran frequently. The refueled Harding Street units have supplied AES Indiana with the type of service that CEI South stated it needed from the proposed CTs.

Indeed, we already recommended CEI South (then Vectren) give serious consideration to refueling in their prior petition for new generation at the Brown station in Cause No. 45052. We stated then that "[a] reasonable alternative would have been the refurbishment of these units through refueling. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT - approximately $45 million for both A.B. Brown units." *Cause No. 45052*, 2019 WL 6770066 at *24 (citation omitted).

What was true in 2019 is still true now. While we do not mandate a utility's choice of generation technologies, we are required to ensure that "[in] acting upon any petition for the construction…of any facility for the generation of electricity, the commission shall take into account…other methods for providing reliable, efficient and *economical* electric service, *including the refurbishment of existing facilities*[.]" I.C. § 8-1-8.5-4 (emphasis added). Refurbishment of the existing Brown units is one option to provide CEI South with capacity and generation to support its load that would have less economic impact on customers than the proposed CT units. As we said in Cause No. 45052,

> Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future... This conservative solution and risk avoidance strategy stands in stark contrast to proposed [CTs].

2019 WL 6770066 at *25.

This is underscored by the fact that in addition to the $323 million[5] for the plants themselves, CEI South is proposing to pass through the cost of a pipeline costing customers $27 million annually *even if the plants are not producing energy.* In addition, if we grant CEI South the right to build the two new CTs, CEI South will pursue the recovery of the balance of the current A.B. Brown through securitization of the undepreciated balance.

In contrast, if CEI South refuels the A.B. Brown units, "Brown would continue to be reflected in rate base under a refueling option." Pub. Ex. 7, CEI South Resp. to OUCC DR 11-3. As testified to by Dr. Boerger, refueled units would be fully depreciated in ten years, even with the addition of the equipment for refueling. Securitization would be unnecessary. The proposed CTs will be depreciated over a period of thirty (30) years. Creating a 30-year burden on customers during a period of electric generation transition makes no sense, unless one considers that it will have the beneficial effect for CEI South's shareholders of increasing rate base and the concomitant returns. Under the proposed alternative, CEI South's customers – already subject to the highest rates in Indiana - will be burdened with the cost of two new CTs, the pipeline, *and* the retired plants for new plants, all in exchange for a projected capacity factor of - at most – six percent. The refurbishment option—which entails considerably less capital expenditure—provides for a retirement "off-ramp" and thus "would seem to provide a potential bridge to the future[.]" *Id.* CEI South improperly rejected this shorter-term, less expensive, and more flexible option.

(2) *Conservation*.

As described below in our evaluation of CEI South's consideration of load management, pursuing the untapped demand response potential in CEI South's service territory would provide the capacity value to mitigate, offset, or defer the need for the proposed 460 MWs of new gas-fired CTs. Evidence of record shows at least 250 MW of demand response capacity that can be procured within a matter of a few years, and is the most cost-effective solution for CEI South's capacity shortfall.

We have previously recognized that "[s]aving energy is the most cost-effective way of meeting future energy supply needs and has the corresponding benefit of reducing the need to build additional generation capacity." *Comm'n Investigation re Demand Side Mgt.*, Cause No. 42963, Ph. 2, 2009 WL 4886392, 281 P.U.R.4th 51, Final Order p. 30 (Ind. Util. Regul. Comm'n Dec. 9, 2009). In fact, while we "recognize[d] the need to approve additional generation capacity as necessary to meet the needs of customers and ensure Indiana's ongoing economic success, [we] also recognize[d] that an important component of long-term planning for Indiana's generation needs is the effective utilization of DSM programs by jurisdictional utilities that have a duty to serve their ratepayers in a cost effective manner." *Id*. This is in concert with our obligations under I.C. § 8-1-8.5-3 to develop statewide analyses to determine long-range needs for expansion of electric generation. Specifically, our statewide plan must examine "the comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership of facilities, refurbishment of existing facilities, *conservation (including energy efficiency)*, *load management*, distributed generation, and cogeneration" (emphasis added). Each utility is also obligated to "assess a variety of demand side management and supply side resources to meet future customer electricity service needs in a cost effective and reliable manner" through its IRP process. I.C. § 8-1-8.5-3(e)(2).

CEI South's consideration of conservation as it relates to the highly cost-effective and readily available demand response resource was inadequate and flawed, and its failure to reasonably explore and model this option biased IRP results against conservation and reinforced CEI South's preferred CTs resource path.

(3) *Load Management*.

Pursuing the untapped demand response potential in CEI South's service territory could provide capacity value that would likely mitigate, offset, or defer the claimed need for the 460 MWs of new gas-fired CTs, but CEI South failed to reasonably consider this readily available, highly cost-effective resource.

Demand response ("DR") is comprised of "[c]hanges in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or [] incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[7] Demand response was historically developed to meet resource adequacy needs to offset the need for peaking generation and/or new transmission, but CEI South has foregone any serious analysis or reflection on its shortcomings, biasing its preferred path to build large CTs that (under its own IRP analysis) will rarely be used. Notably, demand response is a resource where, unlike the expensive and irreversible construction of a large physical asset, programs can be piloted, launched, modified, shut down and relaunched within a period of a few years, making it an effective way to address short term capacity needs like CEI South's situation. It is also compelling, given the economic distress in CEI South's service territory, that the bulk of spending on demand response programs goes directly to CEI South customers, particularly with respect to large nonresidential customers, benefitting economic development in the service territory.

Evidence of record shows that CEI South could acquire significant capacity in a short period of time to eliminate, defer, or at a minimum reduce building these gas combustion units and the related pipeline. The potential is there. Modest assessments of CEI South's demand response potential show at least 227 MW by 2027 with over 200 MW of that consisting of just C&I curtailment. CAC Ex. 3, Attachment JK-2. And, CAC's conservative modeling exercise acquired all incremental DR resources to meet capacity needs, resulting in approximately 250 MW in capacity need reduction over the life of the assets. CAC Ex. 3, pp. 29-30; CAC Ex. 2.

But, CEI South has been doing less than the bare minimum and modeling at that de minimis level. CEI South's current interruptible tariff participation has no more than three customers

[7] https://www.ferc.gov/electric/industry-activity/demand-response/national-assessment-andaction-plan-demand-response

enrolled for a total of 37.3 MW of potential peak demand savings (despite large customers comprising 44% of CEI South's remaining electricity sales). But, even with these three customers' ability to achieve 3.3% of the utility peak demand (38.5 MW), CEI South did not effectively manage the program and achieved 0 MW of actual peak demand savings for the past five years. CAC Ex. 3, pp. 14-15.

The fact that Riders DLC, IC, and IO have not changed in substance since they were introduced in CEI South's 2007 base rates case, despite a consistent lack of participation, demonstrates CEI South's lack of interest in developing this cost-effective resource.[8] CEI South has great candidates for participation: seven customers each with a load greater than 10 MW, and a total of 68 customers each with a load of 1 MW or more that comprise 300 MW total of load. Pet. Ex. 10-R, page 16. CEI South also has additional customers above the 250kW threshold that could be eligible for its interruptible option rider. But, CEI South has simply ignored looking into why their programs have not met their obvious potential. Instead, CEI South continues to make excuses, making unsupported and unsubstantiated claims like, for example, that automotive, food processing, and ethanol industries cannot participate, or are not interested in participating, in demand response programs. Pet. Ex. 10-R, p. 12.

It is telling to us that the record is absent of any showing that CEI South sought to ascertain from its industrial customers not already enrolled in an interruptible tariff the terms and conditions that would be necessary for the customer to do so, or made any adjustments to its IC or IO tariffs in response to customer feedback in the previous five years. CEI South has not offered any evidence either that it attempted to modify its interruptible tariff in order to retain the customer from exiting the tariff; or sought to serve all or a portion of this customer's load through an interruptible tariff.

This lack of seriousness also translated into CEI South's poor consideration of DR in its MPS and IRP analyses. First, CEI South has not adequately considered DR potential. In fact, no incremental industrial demand response was even included for evaluation in the most recent (2019-2020) IRP. CAC Ex. 3 at 26:11-12. There was also no detailed engineering analysis or market study of DR deployment potential in the service territory, evidence showing CEI South's consideration of DR aggregators, a cost-benefit analysis of the implementation of DR programs for the industrial sector within its service territory, or any analysis of availability and capacity of dispatchable behind-the-meter generators ("BTMG") that could participate in DR programs beyond the CHP analysis referenced in the Company's most recent IRP. CEI South simply has not done the research.

Second, CEI South undervalued DR in the IRP in modeling DR as a fixed shape, rather than dynamically dispatching DR resources into the model when economically warranted. We are concerned that CEI South did not allow these resources to provide capacity value to their fullest potential or adapt their dispatch behavior to changing load-resource balance over the study period and scenarios. It is uncontroverted that this led to the IRP modeling software, Aurora, not assigning any capacity value to DR for the purposes of resource optimization. CAC Ex. 3 at 26:5-10.

[8] We note that CEI South's argument that these tariff updates cannot take place outside a base rates case falls flat. Nonetheless, given that CEI South is due for a base rates case before the conclusion of its TDSIC plan ending in 2023, it is a moot point.

We note too that CEI South received one bid for 50 MW of DR in response to its All Source RFP but this resource was not incorporated into any of the portfolios considered in the IRP. 2019-2020 IRP at Fig. 6-5; CAC Ex. 3 at 27:1-2.

We cannot find that CEI South adequately considered DR as a resource when it is likely that properly accounting for DR in its IRP analysis would have significantly reduced or eliminated the need for the construction of the CTs, especially given the shortcomings in CEI South's research of or engagement with this resource. A robust IRP should consider all cost-effective options on the supply and demand sides, treating both on an equal playing field when considering a balanced portfolio. For CEI South, this would mean considering not just a small subset of DR programs already in effect; rather, CEI South should have included a broader portfolio of options with clear targets included as "must run" resources and uncertain options included as selectable resources within the model. DR is a dispatchable resource, and its operation should be modeled as such.

It is not too late for CEI South to make changes in time to meet the capacity shortfall, without the construction of the CTs and pipeline infrastructure: As noted above, significant potential for C&I interruptible DR exists with CEI South's realized enrollment in DR far lower than peer utilities in the State and MISO broadly, despite large customers comprising near 50% of CEI South's remaining electricity sales. CAC Ex. 3, p. 32. Evidence of record shows that simple changes to CEI South's interruptible tariffs and shortcomings in marketing and outreach for large customers could make a significant difference in time to meet the claimed shortfall.

We find it reasonable to explore changes to the interruptible tariff like reducing the minimum curtailment amount to participate in the program (which currently stands at 250 kW), fostering aggregator participation in the market to reduce barriers to customer acquisition,[9] including additional notification times that adjust the capacity payment proportional to their selected period, right-sizing penalty amounts, and integrating CEI South's interruptible tariffs into its EE programs. These are common sense fixes that could bring significant MWs into CEI South's portfolio. At a minimum, CEI South should show evidence of seeking customer input and engaging in adequate utility research to attempt to improve participation and satisfaction with CEI South's interruptible tariffs.

Further, while CEI South offers its demand response portfolio to MISO's Planning Resource Auction as a load-modifying resource ("LMR"), CEI South is not currently procuring any resources that would qualify as LMR-BTMG, Emergency Demand Response, Demand Response Resource ("DRR") Type 1, or DRR Type 2 as contemplated in the MISO tariff. We agree that marketing and engagement to address this shortfall should be considered.

[9] We have previously "strongly encouraged" our jurisdictional utilities to "explore opportunities with [aggregators or curtailment service providers] which may further enhance participation in demand response by customers of all sizes, classes and sophistication". Commission Investigation, Cause No. 43566, 284 P.U.R.4th 225, 2010 WL 3073664 at Order p. 47 (IURC July 28, 2010). Twelve years later, CEI South has failed to take seriously this encouragement from the Commission, and its customers have been deprived of competent investment in load management.

CEI South should have also seriously considered: (1) voluntary price-based programs immediately, with a focus on opt-in rate programs (such as TOU and CPP) and no-risk opt-out offerings (such as PTR and BDR), given that ratepayers should get the benefits of the AMI rollout they paid for; (2) direct load control or automated demand response options, which can often double as energy management tools for energy efficiency programs such as the Company's strategic energy management offering; and (3) rolling out DLC and/or ADR programs to help address commercial customers.

Finally, we must note the doubt surrounding the accuracy of CEI South's load forecast. If CEI South's load forecast is overly optimistic, as it has been in the past, ratepayers will be burdened with paying for plant and infrastructure investment that is not necessary to serve CEI South's load. Pub. Ex. 2, pp. 3, 16; CAC Ex. 2, pp. 46-47. CEI South's industrial sales forecast in its latest IRP assumes a rate of growth that exceeds that forecasted by its load forecast consultant, Itron. It also includes significantly more industrial sales than were included in the Company's 2016 IRP forecast–the same forecast used in the CCGT petition that was denied. CAC Ex. 2, pp. 18-19. We cannot verify whether these industrial sales are likely to happen or not, given the CEI South's last load forecast was Fall 2019 and CEI South did not share the updated information on industrial sales and forecasts not reflected in this load forecast. *Id*., pp. 19-20. CEI South touts the addition of a single industrial customer; however, cross exhibits admitted at the hearing make it unclear as to whether this is truly the additional load CEI South claims, given the relationship to the acquisition of Warrick plant. CAC CX 29, CAC CX 30. This brings into doubt whether 460 MW is a realistic assessment of the capacity shortfall and further highlights the inadequate consideration of load management as an alternative.

CEI South did not adequately consider load management for providing reliable, efficient, and economical electric service.

(4) *Renewable Resources (including Cogeneration).*

The Commission also finds that CEI South improperly rejected renewables as an alternative method for providing reliable service to customers. *See* I.C. § 8-1-8.5-4(2) (requiring consideration of renewables as alternative to proposed facility). Importantly, CEI South understated the capacity contribution of wind, solar, and batteries—including renewable resources CEI South has already constructed or plans to construct—toward meeting MISO reserve margin requirements. The need for the proposed CTs is thus overstated and construction risks overbuilding generation at ratepayers' expense. Moreover, CEI South improperly rejected batteries as an alternative generation resource for meeting this much smaller gap between (i) installed and planned capacity and (ii) the Company's resource adequacy requirements under the MISO tariff.

CEI South claims the proposed CTs are needed to meet a short-term capacity shortfall that cannot be met through existing or planned renewable construction. In calculating this shortfall, CEI South assumed a dramatic decrease in solar and wind capacity value over the next decade. We find that this assumption is not supported by the record. As witnesses Goggin and Sommer demonstrated, the consensus among other utilities, grid operators, and the National Renewable Energy Laboratory is that solar and wind will retain far higher capacity values than predicted by CEI South, even as the total amount of renewable resources on the grid increases, in part because solar and wind have complementary peak generation times-of-day and because geographic diversity of installed resources smooth out daily generation curves. SC Ex. 1 at 25-27. CAC Ex. 2 at 26-27.

MISO, not CEI South, will ultimately determine how CEI South's generation is valued to meet resource adequacy requirements. We therefore credit MISO's 2019 Transmission Expansion Plan (MTEP) and MISO's April 2021 Futures Report which project solar will have a capacity value of 50% until 2023 and then steadily decrease to 30% in 2033. SC Ex. 1 at 30; CAC Ex. 2 at 26. CEI South assumed solar would have a 26.3% capacity credit in 2025/26, declining even further from there each year to 19.6% in 2033/34. Pet. Ex 5-R (Rice Rebuttal), pp. 8-9. Moreover, MISO has actually *increased* wind accreditation in this time from 12.9% to 16.3% over the past decade. SC Ex. 1 at 35. If CEI South's installed and planned solar and wind generation are accredited consistent with MISO projections for solar and current wind accreditation, the discrepancy between CEI South's claimed accreditation and the actual MISO projection adds 165 MW (150 MW for solar and 15 MW for wind) to CEI South's total capacity position for 2026/2027, reducing by half the gap between existing and new capacity and MISO Planning Reserve Margin Requirement that CEI South claims must be filled before its next IRP.

By devaluing the contribution of wind and solar generation to meeting its resource adequacy obligations, CEI South has overstated its need for the proposed CTs. Renewables offer greater capacity benefit as an alternative to the proposed facilities than is reflected in CEI South's IRP modeling.

In addition to addressing a putative capacity gap between its renewable plans and PRMR, CEI South claims that CTs will complement the intermittent nature of solar and wind generation. But CEI South failed to demonstrate that CTs are preferable to batteries to meet this need for fast-ramping supplemental capacity.

We note, as an initial matter, that CEI South appears to have overvalued this ancillary service relative to simply meeting MISO reserve requirements. Large, well-connected grids like MISO are equipped to handle demand and reliability needs, including the deployment of a wide range of resource additions over a geographically diverse area in variable weather conditions. CEI South is obligated to meet its resource adequacy obligations as a MISO participant and to demonstrate sufficient fuel diversity and resource reliability to avoid unreasonable risk to its ratepayers, but it is not required to—indeed, it physically cannot—ensure the reliable operation of an interconnected grid extending not just through Indiana but the entire Midwest.

To the extent CEI South has identified resources with fast-ramping capabilities as a priority as a means of meeting these RTO obligations and as a hedge against a changing grid that will increasingly value such resources, we find that CEI South improperly rejected battery storage as such a resource. The record shows, and CEI South did not contest that batteries can respond much more quickly, flexibly, and precisely to market signals or changes in power system frequency than gas-fired units can, ramping from full charge to full discharge output in seconds or less in response to dispatch signals and offer better ancillary services such as frequency regulation, that may come to be increasingly valued by MISO with greater renewable penetration. SC Ex. 1 at 2. Batteries also offer economic advantages over CTs, as they can be installed quickly and in relatively small numbers, allowing flexibility over time to respond to construction price fluctuation and changes in customer load, thereby mitigating stranded cost or the risk of overbuilding. CEI South's witness Rice concedes that battery prices are expected to fall over time. Pet. Ex. 5-R at 48.

CEI South offered several reasons for rejecting batteries as a renewable alternative to the proposed CTs, none of which were satisfactory. First, witness Rice asserts that batteries cannot provide for "long duration events where the sun is not shining and the wind is not blowing." Pet. Ex. 5-R at 46. But CEI South offered no evidence as to how frequently such events were predicted to occur, why the use of battery resources could not be staggered to cover longer periods, or how the risk of such prolonged periods of reduced solar or wind generation compared to the types of gas supply disruptions CEI South experienced in February 2021. Second, CEI South points to the fact that only one "small" battery project was offered as part of its All-Source RFP. Pet. Ex 5-R at 46. But the RFP produced *eight* storage PPA or purchase proposals and *zero* CT proposals. Pet. Ex. 5 at 7, Attachment MAR-1 at 157. Far from supporting the choice of CTs over batteries, the results of the All-Source RFP from 2019 (which do not reflect the past two-plus years of battery technology development) demonstrated more commercial options for batteries than new gas generation. Third, CEI South suggests that battery storage is not yet ready for implementation. Not so. "[E]xisting grid-connected battery resources and projects in development…for interconnection through 2025 now total over 113 GW." Pet. Ex. 5-R, Workpaper MAR-3 (NERC LTRA) at 39.

CEI South's unfavorable comparison of batteries to the proposed CTs on *economic* grounds reflected an improperly low estimation of their capacity accreditation. CEI South assumed a battery's capacity in *megawatts* is directly proportional to its duration in *hours*, leading it to conclude that a 3-hour battery resource would offer a 71% capacity value. SC Ex. 1 at 39. This assumption is contradicted by NREL analysis showing 2-hour batteries offer 100% capacity value until battery penetrations reach a relatively high level. *Id*. We credit NREL's conclusions, which considerably reduces the total amount of nameplate storage capacity of batteries required to replace the proposed CTs and calls into question CEI South's conclusion that CTs are the more economical alternative.

In sum, the Commission finds that it is premature to reject batteries as an alternative fast-ramping technology to supplement renewable baseload generation over the next two decades or more on a cost basis. Given the large doubts about whether CEI SOUTH needs additional capacity and whether CTs are the lower-cost source of capacity, the Commission finds that CEI South should weigh the optionality value offered by fast modular battery installations against the significant risk of stranded assets from long lead-time investments in CTs.

Indeed, CEI South's own IRP analysis favors renewables rather than the proposed CTs. All four of the competitive portfolios selected by CEI's South IRP process rely heavily on renewable generation resources. CEI South's IRP analysis further showed that an entirely renewable portfolio was likely to be lowest cost. Pet. Ex. 5 at 15-17, Attachment MAR-1 ("MAR-1"), page 91. In three of the five scenarios modeled to test these four competitive portfolios, the Renewables 2030 Portfolio, which includes no new gas generation and retires Culley Unit 3 in 2029-32, had a lower cost than CEI South's preferred portfolio.[10] MAR-1, Figure 8-2, page 246. Significantly, the

[10] The Renewables 2030 Portfolio includes 300 MW of wind in 2022, 731 MW of solar and 126 MW of storage in 2023, and 415 MW of solar in 2024. Pet. Ex. 5, Table 1, page 17.

Renewables 2030 Portfolio had a lower ratepayer cost in the IRP Reference Case Scenario that represents the "most likely future conditions." Pet. Ex. 5, Attachment MAR-1 at 91.

By selecting the High Technology portfolio and proposing construction of two CTs, CEI South rejected its own IRP analysis based on unfounded assumptions about the relative risk of gas and capacity price increases. CEI South selected a portfolio that performs best when gas prices drop below $3/MMBtu indefinitely and the Company's peak load grows 35% in the next seven years. Neither assumption is warranted based on past performance; gas prices reached $6.30/MMBtu in 2021, and CEI South has 10% lower peak customer load now than five years ago. CEI South averred that it declined to select the Renewables 2030 Portfolio to avoid the risk of significantly increased capacity prices, because Renewables 2030 relies on a higher proportion of capacity purchases. As discussed above, however, that the risk of dramatically increased capacity prices is overstated relative to past MISO capacity market performance and CEI South's current capacity purchase agreements. SC Ex. 1 at 18-19.

Finally, we are concerned that although CEI South has represented that the CTs are a means of enabling a primarily renewable portfolio, when asked about off-ramps in the case of excess capacity buildout, witness Rice pointed to reduced solar acquisition relative to the IRP and shorter solar PPAs. Pet. Ex. 5-R at 47-48. Just as troubling as CEI South's unreasonable selection of a preferred portfolio, CEI South has also failed to follow its own preferred portfolio, proposing more gas generation and less solar, wind, and batteries than called for by its 2019/20 IRP plans.[11] This departure compounds the IRP's under-weighting of gas-related risks. Given CEI South has repeatedly emphasized the need for flexibility in the face of changes to the MISO grid, and our continued belief that (as we stated in in Cause No. 45052) CEI South should prioritize flexibility against the possibility of market changes that may render assets uneconomic, we are disinclined to authorize construction of a project that may substitute for, rather than supplement, the transition to renewable generation CEI South has promised.

c. *Ind. Code § 8-1-8.5-5(b)(1) (best estimate of construction).*

We are guided by I.C. § 8-1-2-0.5, which mandates we use all practicable means to "create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services present and future generations of Indiana citizens." We note that our discussion on modeling bears heavily on our analysis in this section. Under I.C. § 8-1-8.5-5(b)(1), the Commission must "make a finding as to the best estimate of construction, purchase, or lease costs" presented in a CPCN request. CEI South's presentation of cost figures does not meet this "best estimate" standard on multiple fronts, making it very challenging for the Commission to even begin to make such a finding.

CEI South's application and rebuttal testimony explain that the best estimate of the cost of the two CTs, as of December 20, 2021, was $334M. We find that the statute requires us to take a holistic view of the project in determining whether CEI South has met its burden to demonstrate that it has provided a best estimate. Because the two CTs cannot operate without the construction of a gas pipeline, we must factor into our analysis whether CEI South has provided the best

[11] *Contrast* Pet. Ex. 5 at p. 25 to MAR-1 at 232 (High Technology portfolio includes purchase or construction of 1,572 MW of renewable generation and storage prior to 2033).

estimate of the cost of the *entire* project, including the capacity reservation on the proposed new gas pipeline. CEI South's testimony states that CEI South customers will have to pay $27.3M per year, through a twenty-year contract, for the pipeline capacity reservation. Pet. Ex. 8, p. 7, l. 3; p. 4, l. 12.[12] The overall cost over the twenty years of the contract will be $27.3M * 20 years = $546M. Therefore, ultimately, the total cost of this CT + pipeline project is $880M.

Given the infirmities in CEI South's modeling, CEI South's failure to account for continuing price increases, and CEI South's failure to negotiate the lowest cost for these resources, we cannot accept that $880M is the best estimate of costs for the CTs + pipeline project.

(1) *Flaws in CEI South's modeling*.

CEI South proposes to build the two CTs simultaneously in 2024. CEI South makes two conflicting claims about the purported cost savings from building the CTs simultaneously, rather than delaying construction of the second CT by nine years, as in the lower-cost Renewables + Gas Portfolio from CEI South's 2019-2020 IRP. First, CEI South witness Jason Zoller claimed that delaying the second CT for five years would result in 25% higher costs. Mr. Zoller did not analyze an actual plan to construct the second CT five years after the first, and further acknowledges "a detailed review was not conducted." Pet. Ex. 7, p. 19, ll. 14-21. CEI South witness Dr. Nelson Bacalao, on the other hand, claims that CEI South modeling actually contained an error, and should have included $52 million in savings from building the two CTs simultaneously. Pet. Ex. 6, p. 16, l. 16 - p. 17, l. 18. Dr. Bacalao cites figures from Volume 2 of the Integrated Resource Plan, but does not give any explanation for the $52M figure or support it in any way. By contrast, the comments of Citizens Action Coalition to CEI South's Integrated Resource Plan analyze the claimed $52M savings closely, and determine that they are not supported. Public IRP Comments pp. 26-27. Due to the conflict between the two CEI South's estimates of claimed savings, and the lack of support for those claims, we cannot accept the credibility of either CEI South estimate of the cost savings from building the CTs simultaneously.

(2) *CEI South's failure to account for continuing price increases.*

Intervenors raised concerns over escalation of costs, which CEI South acknowledged were valid. Pet. Ex. 2-R, pp. 30-31. CEI South agreed that costs for the CTs had risen significantly from the costs in CEI South's original modeling, due to "an unusual price escalation in 2021 and future uncertainty regarding where commodity prices for material and supplies costs will go in the next couple of years." *Id*., p. 32.

In the Engineering, Procurement, Construction ("EPC") Contract that CEI South negotiated with Kiewit, CEI South agreed to capped increases for some, but not all, of the variable

[12] This does not include the actual fuel that the CTs will use when they are in operation for 1-2% of the year - the fuel costs will appropriately be considered in the Fuel Adjustment Clause proceedings, but the costs of pipeline construction, operation, and capacity reservation, which apparently are being borne by CenterPoint via its Precedent Agreement with Texas Gas, must be considered here.

costs in the contract. These caps, if met, would add more than $34M, or 7.2%, to the current project cost estimate. *Id*. at 34, Table 2.

Beyond that, the EPC Contract also envisions increases for other variable costs, without any cap to protect CEI South customers. For example: at the hearing, Mr. Games discussed price adjustments based on increases in the price of metal and metal products, as measured by the Federal Reserve's Producer Price Index. Tr. A-27, l. 24 - A-32, l. 15. The June 2021 Purchase Price Index was 294.2; as of January 2022 it stood 13% higher, at 333.606. Mr. Games explained that "it's only fair [to Kiewit] to have some kind of price adjustment index to cover these type of increases…" Tr. A-31, ll. 10-12.

The price increases that CEI South customers will have to pay, due to increases in the price of metal and metal products, are detailed in the EPC Contract's Exhibit EE Section 5.5. Specifically, Exhibit EE Section 5.5 sets forth how price increases will impact the contract price. According to the formula provided in the Contract, if the Producer Price Index at the time of the Notice To Proceed is the same as it stood in January 2022, CEI South customers would pay a significant increase for these two CTs. CAC CX 1.

CEI South's rebuttal testimony argues that a different EPC contract for the two CTs would have faced the same price increase issues, and "would not have improved the project's financial position." Pet. Ex. 2-R, p. 31. But CEI South did not evaluate whether the recent price increases would have affected the decision to build the two CTs at all. Again - the portfolio with the two CTs was not the least-cost option from CEI South's modeling. Without Commission approval, CEI South was not locked into the decision to construct the CTs - and price increases of this magnitude (compared to the cost inputs used in the IRP) required CEI South to re-evaluate. Given that this case concerns just a short-term capacity need in 2026 and 2027, we cannot commit CEI South customers to absorb these price increases, capped and uncapped, for a long-term capacity resource.

(3) *CEI South's failure to heed market signals regarding the pricing and availability of gas-fired resources*.

In our 45052 order, we ruled that CEI South's Request For Proposals had been "unduly restrictive", and failed to obtain valuable market data about what resources were available at the lowest cost. 45052 Order p. 21. In response, CEI South conducted an All-Source RFP beginning in June 2020 "to gather resource availability and pricing information for various resources…" Pet. Ex. 5, pp. 6, 28. This All-Source RFP provided a clear market signal about the availability and pricing of gas-fired power plants: CEI South received no bids at all for single-cycle combustion turbines, and quickly dismissed the handful of other gas-fired power plant bids the Company received. *Id*., p. 7, ll. 10-16.

However, CEI South ignored that clear market signal from the RFP results, and pushed forward with gas-fired resources without any strong bids from market participants. For every technology except gas plants, CEI South embraced the concept that the resources modeled for the IRP should be guided by the RFP bids: in its IRP modeling, CEI South only included only bids that were considered "Tier 1 bids": "only projects that provided a firm price and were either on CenterPoint Indiana South's system or included a delivered price were included within modeling inputs". Pet. Ex. 5, p. 6, ll. 20-25.

But since CEI South did not receive any "Tier 1 bids" for gas-fired generating plants and no bids at all for CTs, CEI South instead used generic price inputs for CTs in its IRP modeling. By choosing CTs based on that generic price input, CEI South conducted exactly the same type of "unduly restrictive" RFP that we rejected in Cause No. 45052.

On June 20, 2017, Vectren South issued a RFP for dispatchable resources, between 600 MW and 800 MW, located in MISO Zone 6. *Cause No. 45052*,2019 WL 6770066 at *23. We rejected the CPCN request resulting from a bid (for a CCGT) to that RFP, in part because the RFP was "unduly restrictive." *Id*. CEI South's October 2020[13] RFP was, if anything, more restrictive: it was limited to a specific technology (a 2x0 simple-cycle gas-fired combustion turbine) and a specific location (the A.B. Brown site). Pet. Ex. 7, p. 14, l. 27-p. 15, l. 3.

In sum, CEI South ignored the clear market signal from its All-Source RFP that CTs were not the best option to satisfy any outstanding capacity needs. CEI South next conducted the same type of restrictive RFP that we rejected in 45052. For those same reasons, we cannot accept the bid resulting from that restrictive RFP as the best cost estimate for a resource to satisfy CEI South's capacity needs in 2026 and 2027.

Ultimately, CEI South's case does not present an accurate and complete estimate of the cost of either the CTs (or the pipeline, as discussed below). Without this crucial information, CEI South has not met its burden to show that it has presented the best estimate of the project.

d. *Ind. Code § 8-1-8.5-5(b)(2)(A) (consistency with Commission's statewide analysis).*

I.C. § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether CEI South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. Included in that Report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including CEI South.

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

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

[13] Pet. Ex. 7, Confidential Exhibit JAZ-4, p. 5.

The evidence does not convince us that such a large, long-term shift from one fossil fuel to another fossil fuel puts CEI South on the path to appropriate fuel diversity.

On page 5 of the Statewide Analysis it says:

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

As we discuss in more detail elsewhere, CEI South's proposal appears to deprive it of future flexibility in utility resource decisions in order to minimize risks. To the contrary, CEI South's proposal saddles it and its customers with paying for an expensive, long-lived generating plant that seems likely to constitute the vast majority of CEI South's resource fleet for a long time. The burden on customers to pay a return on and return of that capital expense seems likely to significantly narrow CEI South's options for any future change of course to adapt to circumstances and changes.

In explaining the importance of sound long-range planning on page 56 of the Statewide Analysis, it says, "The credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." Nothing in CEI South's evidence convinces us that its proposal provides any off ramps that would allow CEI South to react to changing circumstances and make appropriate changes in resources. To the contrary, CEI South's proposal seems to close most off ramps for the foreseeable future.

Accordingly, we cannot find from the evidence that CEI South's proposal for the CTs is consistent with the Commission's Statewide Analysis.

e. *Ind. Code § 8-1-8.5-5(b)(2)(B) (consistency with CEI South's IRP).*

The Legislature has decided that before we approve any utility proposal to construct new generation, we must approve or disapprove, in whole or in part, the "utility specific proposal submitted under section 3(e)(1) of this chapter[.]" I.C. § 8-1-8.5-5(b)(2)(B), (d). This is the utility's IRP. I.C. § 8-1-8.5-3(e)(1). For the reasons detailed below, we disapprove of CEI South's IRP. Flaws in CenterPoint's 2019-2020 Integrated Resource Plan rendered the exercise unreliable and inaccurate, and preclude us from approving the proposed CTs.

Before discussing those flaws, we note that CEI South's preferred IRP portfolio, the nominal "High Tech" case, was neither the lowest risk nor the lowest cost portfolio identified in the IRP process. According to CEI South's IRP modeling, the "Renewables + Flexible Gas" (which includes just one CT in the 2020s) is expected to be lower cost (on an NPVRR basis) in all five scenarios studied. Even if we were to take CEI South's modeling at face value, we do not have confidence in the Company's selection of a preferred portfolio, especially with respect to the inclusion of two CTs.

Our confidence wanes further as evidence developed by intervenors highlights a concerning number of flaws in the inputs and methodology used in the IRP process. First, the

Company's IRP modeling contained multiple assumptions that tended to overstate the price of renewables and battery storage, limited the extent to which these resources could be selected during key periods in the optimization, inappropriately accredited new solar, and limited the availability of new demand response resources. These assumptions had the effect of biasing the resource optimization against renewables and battery storage. To similar effect, CEI South assumed a capacity value for solar resources that is much lower than what MISO is projecting or that which we find reasonable on the record, especially considering that solar additions have been lower than CEI South projected. This solar capacity value assumption has the effect of overstating the CEI South's need for capacity. In addition to appearing to disadvantage renewable and battery storage resources, we find that CEI South assumed unreasonable cost savings for building the second combustion turbine in 2025 compared to adding that at a later date, tilting the analysis further.

Second, the Company's modeling relied on stale and unrealistic sales forecasts. The Company's industrial sales forecast in its 2019-2020 IRP assumes a rate of growth that exceeds that forecasted by its load forecast consultant, Itron; has not been updated since Fall 2019; and strongly departs from the downward trend in industrial sales observed since 2017. CEI South declined to recast its sales notwithstanding significant changes since 2019 (e.g., impacts of the pandemic) and the fact that actual industrial sales were far lower than forecasted in 2019. An exaggerated view of growth can have the perverse effect of chilling economic development: If forecasted growth years into the future justifies greater capital investment in new generation resources today, cost of service may increase to a level that discourages entry of new energy-intensive or energy-conscious businesses. Further, even if the growth in industrial load were to materialize, declines in other customer classes compared to the IRP forecast would eliminate this impact on total load. CEI South has had negative load growth rate from 2013 to 2020 (-2.7%), and non-industrial load has declined in every year since 2018, while the IRP forecasted growth in all of these years, including, incorrectly, in the year 2019 before the pandemic.

We have previously observed the importance of refreshing data and rerunning models when significant changes have occurred, and reiterate those points here. *See e.g.*, Cause No. 45052, 2019 WL 6770066 at * 29 ("Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT."); *Indianapolis Pwr. & Light*, Cause No. 44339, 2014 WL 2091348, *29 (Ind. Util. Regul. Comm'n May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Including the cost of firm transportation capacity, the total cost of CEI South's proposal approaches the capital cost of the CCGT proposed in Cause No. 45052, and the impacts of the pandemic have had profound effects. Both points make it reasonable to question why CEI South would not update its industrial forecast, particularly after seeing actual sales in 2020 and 2021 notably lower than forecast. The need to update these stale projections is perhaps even greater here because of the impacts of the pandemic and supply chain issues, as well as the fact that CEI South's 2019-2020 IRP modeling, on its face, would appear to support just one CT or no CTs as lower-cost, lower-risk solutions.

Third, CEI South used limited and unreasonable assumptions related to demand response resources. Its analysis of demand response potential was limited in that CEI South only modeled existing resources without including any additional demand response resources to possibly be selected in the optimization modeling. And although the model used by CEI South is capable of modeling demand responses based on economic dispatch, that was not done here. Instead, demand response resources were modeled as a fixed shape, preventing the model from recognizing their full capacity value or potential to adapt dispatch behavior. Additionally, although CEI South received an RFP bid for 50 MW of demand response, that bid was excluded from modeling. In these ways, CEI South failed to model supply- and demand-side resources on a level playing field, possibly missing cost-effective demand side resources as a result.

Fourth, owing to the limited transparency around CEI South's IRP modeling, we cannot be certain that more mistakes, unreasonable inputs, or unsound methodologies were applied. Assurances that error checking was done by Siemens before this proceeding began hold little value given that (i) errors in several key inputs were identified only in the course of responding to discovery requests from intervenors (necessitating an extension of the procedural schedule of this case) and (ii) Siemens has not allowed any party to this proceeding to review all the modeling files. Witness Sommer cautions against reliance on evidence that cannot be fully reviewed by intervenors or this Commission (CAC Ex. 2 at 17-18), and we largely agree. As expressed by our Director of Research, Policy, and Planning: "Prudence dictates that credible and transparent analysis is essential for assessing reliability and cost ramifications." (Director's Final Report on the 2016 Integrated Resource Plans at 25). We strongly encourage CEI South and all regulated utilities to engage consultants willing to provide transparent work product and to use modeling software that will enable independent third-party review. If a modeling consultant will not allow disclosure of its modeling files—not even under the protection of routine non-disclosure agreements—it is a mistake to engage that consultant's services for an IRP process where credible and transparent analysis, available for review by stakeholders, is essential.

Fifth, correcting certain inputs in the IRP modeling results in the selection of a plan that is lower cost and does not include the combustion turbines. As reflected in witness Sommer's testimony, when given more realistic and reasonable inputs, the model favored investment in demand response, solar, wind, and battery storage resources. This suggests potential for lower-cost and lower-risk portfolios than that preferred by CEI South, if only the modeling process had more accurately characterized all resources—including supply- and demand-side opportunities—and modeled their potential performance on a level playing field.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with CEI South pointing to another gas resource conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co*., Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, (Ind. Util. Regul. Comm'n Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at *37.

CEI South touts the frequency with which its various modeling exercises and analytical steps selected CTs as confirmation that two CTs are the most appropriate resource option. Commissioners in Michigan recently cautioned against drawing just such a conclusion. *See, In re DTE Elec. Co*., Case No. U-18419, 2018 WL 2057719, 344 P.U.R.4th 185 (Mich. Pub. Serv. Comm'n Apr. 27, 2018) *43 ("The Commission expects that an effective IRP should produce results, under certain scenarios, that show the preferred course of action is not actually the best option. This is how we know the IRP is testing the robustness of the preferred course of action by examining how it performs under various assumptions, even if those assumptions may seem unrealistic today.") What CEI South touts as confirmation of its results has been judged elsewhere to potentially "give the impression that modeling results were steered or forced into a pre-determined result." *Id.*

An additional oversight in Mr. Rice's analysis is shown through his criticism of Dr. Boerger's analysis. Dr. Boerger noted that the discount rate used in Siemen's analysis did "not remove expected inflation." Pub. Ex. 1, p. 13, l. 14 - p. 14, l. 2. Mr. Rice responded that "[a]ll assumptions entered into the Aurora model were in real US dollars…which does not include the effects of inflation." Pet. Ex. 5-R, p. 40, ll. 5-8. However, the discount rate of 7.71% used by CenterPoint reflects the weighted average cost of capital, which is composed of the cost of debt and equity. (2019/202 Integrated Resource Plan, p. 257). This cost of debt and equity reflect the expectations of an investor investing in the utility, which include the expectation of inflation, as acknowledged by Mr. Rice on cross examination. Tr. I-32, ll. 16-20. Therefore, while Mr. Rice may argue that the discount rate is not intended to include inflation, the effects of inflation are already integrated into this rate, and Dr. Boerger was correct that inflation was not removed.

Another omission in Mr. Rice's analysis relates to the inclusion of pipeline costs in his modeling. The pipeline contract is over 20 years, and these costs are included in the analysis. However, the expected lifetime of the new CTs is 30 years. Tr. I-33, ll. 2-3. Mr. Rice acknowledged that and the end of the current gas contract, CenterPoint will "have to evaluate [its] options at that point and potentially sign an additional contract." Tr. I-33, ll. 8-9. Therefore, his analysis does not include an additional 10 years of gas transportation costs after the current contract expires, potentially adding significant cost.

The failure of Mr. Rice to account for these issues, in addition to the other errors noted his analysis, weaken his analysis and CenterPoint's proposal. Looking at the proposal as a whole, we cannot find sufficient support based on Mr. Rice's analysis.

For these reasons, we disapprove of CEI South's IRP. Approval of CEI South's IRP is a prerequisite to our approval of CEI South's proposal to construct new generation. I.C. §§ 8-1-8.5(b)(2)(B), (d). Therefore, our conclusion below must be that the application does not satisfy the requirements of Chapter 8.5. We note that our disapproval of CEI South's IRP "shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity." I.C. § 8-1-8.5-5(d).

f. *Ind. Code § 8-1-8.5-5(b)(3) (public convenience and necessity).*

I.C. § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CTs. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. I.C. § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate." "[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In that case, the court approved the Commission having included in its public interest determination consideration of the impact on employment in the coal industry. *Id*.

(1) Bill Impact, Economic Considerations in Service Territory.

Over the last 12 years from 2009 until 2021, CEI South has had the highest residential electricity bills in the State, based on a monthly consumption level of 1,000 kilowatt hours, for all investor owned electric utilities and all jurisdictional electric utilities (with the exception of 2010 where Marshall County had the highest electric bills among all jurisdictional electric utilities). CAC Ex. 1, pp. 5-6 and Attachment KLO-1. CEI South's average residential bill in 2020 far exceeded the average bill in Indiana and in the nation. *Id*., pp. 6-7 and Attachment KLO-2. CEI South residential electric bills are higher than our Midwestern neighboring states of Illinois, Kentucky, Michigan, Ohio, and Wisconsin too. *Id*.

CEI South's own witness refers to the "magnitude" of this additional investment in testimony when requesting accounting treatment from the Commission and states her concern for whether the Company's shareholders will suffer unless it is granted this extraordinary request. Pet. Ex. 9, p. 5, ll. 23-27. Yet, CEI South offers no relief to or risk minimization plan for its customers who have not only been suffering due to the highest bills in the State for years, but whose suffering will be exacerbated if we were to approve a request of such "magnitude" from CEI South's captive customers. For residential customers, the estimated impact is another $23 per month.

On top of that, CEI South has gone from fourth worst residential electric customer satisfaction to second worst, according to the J.D. Power survey results from 2020 and 2021, raising the question of what at all CEI South is doing well for its residential electric customers. CAC Ex. 8, pp. 3-25.

In making this decision, we are very aware that both the city of Evansville and Vanderburgh County experience higher poverty levels and lower household incomes than the averages for the State of Indiana as a whole. In particular, Evansville has an 83% higher poverty rate than the State as a whole with a 29% lower household income. CAC Ex. 1, p. 8 and Attachment KLO-3. The U.S. Department of Housing and Urban Development even declared Evansville a Promise Zone in 2016 as the "population within [Evansville] of nearly 39% of whom live below the poverty line." CAC Ex. 1, p. 9, quoting the City of Evansville's website. Notably, CEI South presented very limited economic impact evidence itself. We find it concerning too that not one individual spoke in favor of the proposed CT plan amongst dozens of attendees at the field hearing in this proceeding. CAC Ex. 1, p. 10 and Attachments KLO-4 and -5.

If it were unequivocally clear that CEI South's plan would be the least expensive for ratepayers in the long run, our decision might be different. But, for a variety of reasons we discuss elsewhere that is not clear. Accordingly, we find that potential bill impact of CEI South's plan weighs against our approval of it.

(2) Environmental concerns.

We are well aware that the Indiana and U.S. economies, indeed the world economy, will likely shift to relying significantly less on carbon emitting processes. The exact path by which that will happen cannot be known. It may be driven, in varying degrees by voluntary, collective action, by political pressure, by economic incentives and/or disincentives, and by government mandate. It may involve any combination of substituting lower carbon emitting technology in place of higher emitting technology or substituting non-carbon emitting technology for carbon emitting technology. CEI South's preferred plan is a long-term bet (with customer's money rather than the Company's) on substituting a carbon (and methane) emitting fuel (natural gas) for its current carbon emitting fuel (coal). CEI South advances this plan at the same time that other utilities are finding that substituting non-carbon emitting technology for carbon emitting technology is a feasible and preferred path. Given the current state of uncertainty, this large bet on carbon emitting natural gas seems unduly risky. A more flexible approach that leaves the ability to adapt to future circumstances seems more prudent, particularly when it appears more likely to mitigate the rate impact on customers.

(3) Risk.

As we observed in Cause No. 45052, citing the Statewide Analysis, "[a] key consideration in long-term resource planning is the need to *retain maximum flexibility in utility resource decisions to minimize risks*." *Cause No. 45052*, 2019 WL 6770066 at *27 (emphasis added). The proposed CTs do not minimize risk and, indeed, create a significant risk of stranded assets for ratepayers. CAC points out that CEI South's risk analysis took a one-sided view of capacity purchase and market purchase risks and did nothing to consider the risk of future methane regulations or restrictions. As we have discussed above, CEI South significantly overstated the risk of capacity market purchases, particularly in the period between the proposed CTs' initial operation and the next IRP, relative to the risk of a nearly-billion-dollar investment in a type of generation that is likely to be subject to significant environmental regulation in the future and which depends on construction and operation of a pipeline that has not been approved by the relevant federal agency, let alone built. CEI South's own capacity contracts do not support its forecasts as to future capacity prices and have a price per MW-day far beneath the estimated cost of the proposed CTs. CEI South's overweighting of the risk of capacity market purchases caused the Company to override the results of its own IRP, which pointed to an all-Renewables portfolio (as discussed above) as lower cost in three of the five scenarios modeled. Investing in 460 MW of gas generation is the *least* flexible option CEI South contemplated, and does not minimize risk.

We are further concerned that CEI South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.*, Cause No. 44794, 2017 WL 1632316 at *31 (Ind. Util. Regul. Comm'n Apr. 26, 2017). The proposed CTs introduce other types of risk not incorporated into CEI South's IRP analysis or case-in-chief. There is the upfront risk that the lateral pipeline necessary to serve the proposed CTs will not be approved by the Federal Energy Regulatory Commission. Sunrise Ex. 1 at 5-6. Gas prices have demonstrated significant volatility since CEI South completed its IRP, well exceeding (at times) prices CEI South did not forecast until 2035 or later. SC Ex. 1 at 46; *See Indianapolis Pwr. & Light*, Cause No. 44339, 2014 WL 2091348 at *29 (Ind. Util. Regul. Comm'n May 14, 2014)

("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). These prices may be inflated further by carbon pricing or other fossil fuel regulations. *Id*. Choosing to construct new generation at this time also introduces inflation risks, which CEI South has failed to fully mitigate in its construction contracts. As Winter Storm Uri illustrated, gas generators are vulnerable to correlated outages, which risk price spikes for customers and do little to address reliability concerns for the MISO grid as a whole. SC Ex. 1 at 49. Nor are prolonged gas outages limited to extreme weather events, as the continued outage at Eagle Valley has demonstrated. Cause No. 38703 FAC 133-S1.

Indeed, as a result of these season and correlated outages, there is a real possibility that the capacity accreditation of the proposed CTs will be less than CEI South anticipates. MISO has stated that if it switches to a seasonal capacity construct, correlated outages, including at times of peak usage (including the coldest days of winter) will be addressed in the performance-based accreditation of gas resources, which may lower the CTs' accreditation in winter.

Additionally, we are not persuaded that CEI South accurately presented or assessed cost risk associated with the proposed CTs. As reflected in the IRP, portfolios adding a single combustion turbine in the near-term (i.e., Reference portfolio and Renewable + Peak Gas portfolio) performed better than the preferred portfolio on the Cost Uncertainty Minimization objective. MAR-1 at 253, 259–60. Concerning cost risk for the proposed CTs in isolation, OUCC witness Alvarez provided testimony comparing CEI South's cost estimate to Lazard's Levelized Cost of Energy Analysis and the U.S. Energy information Administration's ("EIA") base and regional overnight capital costs for new electricity generating technologies. Pub. Ex. 2 at 10–11. Based on those comparisons, Mr. Alvarez opined that CEI South's cost estimate may be unrealistically low and there may be risks of cost escalations. Pub. Ex. 2 at 11. Although Mr. Games' rebuttal argued that Mr. Alvarez did not know the intended purpose of the Lazard data used for comparison, that criticism was shown to be a misrepresentation of Mr. Alvarez's deposition testimony. Tr. B-33 – B-37. Mr. Games offered no explanation himself of that intended purpose and did not say that the comparison is unsound. Pet. Ex. 2-R at 34–35. Nor did Mr. Games respond to Mr. Alvarez's EIA comparisons. Accordingly, we credit Mr. Alvarez's testimony as offering sound comparisons tending to show the potential for higher costs. That potential for higher costs is realized with the final EPC contract, which commits CEI South to a range of variable cost components and addresses inflation exposure via indexed pricing.

In light of these concerns, we conclude that CEI South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. Instead, the risk analysis depends on stale inputs, ignores known risks, and arbitrarily scores portfolios.

(4) *Pipeline*.

I.C. § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CTs. "[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995).

Though not directly seeking approval, the lateral pipeline must be treated as part-and-parcel of the proposed gas combustion turbines. But for the combustion turbines, there would be no need for the proposed new lateral, to be built, owned and operated by Texas Gas Transmission, from Robards, KY to the A.B. Brown site near Evansville. And but for the proposed new lateral, the proposed combustion turbines would lack an adequate fuel supply, according to CEI South's witnesses. In addition to their practical inseparability, the proposed new lateral significantly adds to the total cost to customers for the proposed combustion turbines. CEI South's contracted cost for the first twenty years of transportation capacity on the new lateral exceeds the estimated capital cost for the proposed combustion turbines. For these reasons, answering the question of whether the combustion turbines are required by public convenience and necessity requires examination of both the combustion turbines and the new lateral needed to supply fuel.

Our inquiry with respect to the new lateral is distinct from FERC's Certification process under the Natural Gas Act, which is presently pending.[14] Our concern is not whether the lateral meets the NGA's requirements under federal law. FERC's review of the proposed pipeline is separate from this proceeding. Rather, our interest is in assuring that CEI South's resource choice passes muster under Indiana law. It is our duty to examine whether the planned fuel supply mechanism for the proposed combustion turbines is reasonable, the result of competitive processes, cost-effective, necessary, and ultimately serves the public interest. We will also address CEI South's stated intention of recovering the new TGT lateral costs via its Fuel Adjustment Clause ("FAC").

CEI South relied on its analysis of pipeline needs for the CCGT proposed in Cause No. 45052. When CEI South informally pursued proposals from pipeline companies in the fall of 2020, it assumed construction of two H Class units, requiring 5,417 MMBtu/hour. As explained by Ms. Grizzle, at the time, CEI South had not decided between the F-Class and H-Class CTs, and thus conservatively sought bids capable of serving the higher-demand H-Class units. Tr. at C-11, ll. 8-15. But CEI South had selected F-class units as part of the preferred plan in its 2019-2020 IRP published a few months prior, on June 29, 2020. Two F-class combustion turbines would require 4,630 MMBtu/hour. CAC Ex. 2, Att. AS-7, at 16. At the time of negotiating with pipeline companies, Ms. Grizzle was advised by her colleagues that the H-class demand was the full requirements for the pipeline, rather than the requirements associated with the F-class CTs that had been selected in the Company's IRP. Tr. at C-9, ll. 18-21; C-11, ll. 16-25. CEI South's resulting contract with Texas Gas is based on the H-class hourly demand of 5,417 MMBtu/hour and has not been updated based on the F-class units that the Company is actually proposing in this proceeding. Tr. at C-10, ll. 19-23.

Again, the 20-inch pipeline intended to supply two F-class turbines is very similar to the one proposed to supply the CCGT the Commission rejected in Cause No. 45052, but is actually larger in capacity and costs a significant amount more to build (at $500 million) with no ownership by CEI South or customers compared to the CCGT pipeline (at $87 million) with CEI South ownership. Cause No. 45052, Tr. H-13, ll. 7-14. This, despite the facts that the proposed CTs are smaller than the CCGT proposed in Cause No. 45052, require less gas on an hourly basis, and are forecasted to run infrequently in all years modeled, if at all. We are concerned CEI South is using

[14] *See* FERC Docket No. CP21-467 (considering TGT's application for a Certificate of Public Convenience and Necessity under Section 7 of the Natural Gas Act, 15 U.S.C. § 717f).

electric customers a to finance excessive and unnecessary gas infrastructure expansion. E.g. CAC Ex. 2 at 36 ("CenterPoint is acquiring gas transmission capacity that greatly exceeds that which is needed to supply these units, and the Commission has no way to evaluate whether opportunities to acquire less transmission capacity are available.").

CEI South did not pursue a formal request for proposals for the pipeline. Instead, CEI South selected four pipeline companies from which to informally invite bids. Tr. at C-14, ll. 2-13. The solicitation was not made publicly available in written form for any pipeline vendor to see and respond to. Tr. at C-14, ll. 14-17. Rather, CEI South contacted the four potential vendors by e-mail and/or telephone. Tr. at C-14, ll. 18-21.

This would be a 20-year commitment to pay $27.3 million in annual costs to serve a pair of CTs with projected capacity factors of only 1%-3%, with no exit plan if the situation changes. There does not seem to be anything in the contract to construct the pipeline that allows for CEI South to exit from these obligations, even if one or both of the CTs are taken out of service during the 20-year term. The inability to exit the contract means that CEI South will be obligated to pay over half a billion dollars for firm gas delivery costs regardless of whether other capacity options arise during the 20-year period that may be preferable from a cost or environmental perspective to the proposed new CTs. Moreover, there does not appear to be anything in the pipeline contract that would provide meaningful protection to CEI South from the possibility that the pipeline will not be built in a timely fashion, or at all. In fact, CEI South did not evaluate if the $27.3 million annual cost of the pipeline would continue even if service is discontinued after 10 years. IG Ex. 1, p. 16, CEI South response to Sunrise 2-16, Attachment MPG-1, page 14.

CEI South also has made no effort to defray the $27.3 million annual cost of the pipeline. 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. CEI South has not presented any evidence to suggest that it will try to defray these CT costs, or even whether options such as curtailable gas delivery capacity sales might be a better avenue to reduce costs to CEI South customers. To the extent that such sales are feasible, CEI South should be required to minimize the cost burden on ratepayers by producing alternative revenue sources without impairing CEI South's ability to recall the capacity when needed to provide service to its customers. In addition, CEI South has not demonstrated that the location of the pipeline (or even the location of the CTs themselves) has been oriented on achieving cost efficiency. Notably, the proposed new gas lateral project involves crossing the Ohio River even though the TGT system and other pipelines already serve southwestern Indiana. And, CEI South did not meaningfully evaluate smaller and potentially more cost-effective firm gas transportation options.

Rather than attempting to defray the costs in any of these respects, CEI South just went back to the same interconnection point on the same TGT system as in Cause No. 45052 and failed to even use a formal RFP to responsibly competitively bid this project.

We are troubled too that CEI South gave conflicting information as to what the flow rate (in MMBtu/hour) required for the proposed CTs is. The informal RFP considered pipelines to fuel H-Class turbines, despite the fact that CEI South had already decided months earlier to go with F-Class turbines. Ms. Grizzle, who conducted the informal RFP phone call, testified that she had not been informed the gas turbine would be F-Class (Tr. C-44, ll. 1-7) although the Director of Indiana Electric Regulatory and Rates thought it a "fair assumption" she was. Tr. H-16.

It is not certain that the pipeline can even be built, given FERC is still considering the application for construction and is requiring an Environmental Impact Statement, a notable requirement where high-pressure gas infrastructure is being installed under a major waterway like the Ohio River. Under that schedule, a FERC decision on the pipeline may not occur until November 23, 2022. *See* FERC Oct. 7, 2021 NOI to Prepare EIS (Cause CP21-467-000) at page 6, attached to IG Ex. 1, Attachment MPG-2. At a minimum, CEI South should not incur any expenses or otherwise commence construction of the CTs or other infrastructure unless and until FERC issues its ruling. In discovery, CEI South indicated that if FERC denies the Petition, then it would have to purchase additional capacity until it determines what to do in the next IRP. IG Ex. 1, CEI South Response to Sunrise 2-4, Attachment MPG-1, p. 13. CEI South also has no idea if shorter FERC approval if proposed alternative routes. Although a FERC denial of the request to build the pipeline may not necessarily be either TGT or CEI South's fault, it is nevertheless a risk that should be considered in the context of evaluating CEI South's proposal in this proceeding.

Mr. Greenley suggested moving ahead with CT construction via a "Limited Notice to Proceed" is unavailing, but CEI South and Keiwit have a detailed contract, and that contract nowhere mentions a "Limited Notice to Proceed". We are concerned to hear a regulated utility offer sworn testimony that it intends to pursue activities not covered under the EPC contract.

CEI South is proposing to treat the costs of the new gas pipeline as a cost subject to recovery through its Fuel Adjustment Clause ("FAC"). CEI South proposes recovery of the pipeline contract cost through the FAC regardless of whether energy is generated by units; the TGT contract is based on a maximum demand reservation, regardless of how much gas is actually transported or consumed. The cost of the gas lateral does not vary based on the energy generation of the CT, and to the extent that the CTs are not generating electricity, inclusion of the pipeline costs violates the FAC statute, I.C. § 8-1-2-42.

The FAC statute enables electric utilities to recover "the cost of fuel to generate electricity[]" that are either higher or lower than what is embedded in rates. I.C. § 8-1-2-42(b).

> When such application is filed the petitioning utility shall show to the commission its cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity, for the period between its last order from the commission approving fuel costs in its basic rates and the latest month for which actual fuel costs are available….The commission shall conduct a formal hearing solely on the fuel cost charge requested in the petition…and shall grant the electric utility the requested fuel cost charge if it finds that:
> (1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible…
> (4) the utility's estimate of its prospective average fuel costs for each such three (3) calendar months are reasonable after taking into consideration:

> (A) the *actual* fuel costs experienced by the utility during the latest three (3) calendar months for which *actual* fuel costs are available; and
> (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

I.C. § 8-1-2-42(d) (emphasis added).

CEI South acknowledged that it would include the pipeline costs ($27.3 million/annually) in every FAC proceeding, regardless of whether the proposed CTs were running in the relevant three-month period. Should CenterPoint do so, it would be violating the statute's requirements that recovery is based on the "cost to…generate electricity" and the "*actual* cost". *Id.* In addition, the question of whether "the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible" cannot be answered positively if the cost *is not related to the generation of electricity.*

There are other reasons why an FAC proceeding is an inappropriate vehicle to consider the reasonableness of costs under the CEI South – TGT Precedent Agreement. Almost all of the Precedent Agreement cost is a fixed dollar amount that will not vary from year to year or quarter to quarter. This type of cost would be better considered in a base rate proceeding. Inclusion in the FAC is also inappropriate absent a close analysis of the reasonableness of the cost, which cannot be completed in the truncated procedural schedule of an FAC.

CEI South contracted with Texas Gas for the full capacity of the proposed new pipeline lateral (220,000 MMBtu/day) and did not attempt to negotiate a lower contractual demand level (with a lower total daily demand charge) despite that its CTs could use, at full burn, only around half the nominal 220,000 MMBtu/day level of gas transportation. Tr. at C-46 to C-49. According to CEI South (a combination utility that separately operates a gas distribution service), one reason it chose to contract for the full capacity of the pipeline lateral is to avoid the threat of bypass by gas customers. CAC Ex. 2, Att. AS-7, at 10-11, 14. CEI South Witness Ms. Grizzle confirmed that, as in Cause No. 45052, the Company views the avoidance of possible bypass by prospective gas customers (who could "bypass" the Company's gas service by contracting for spare capacity, if it existed, on the new pipeline lateral) as a "benefit." Tr. at C-16 to C-17.

It is difficult to understand why CEI South has contracted for capacity on the lateral – with what would be a ratepayer cost of $11.6 million annually for the lateral alone – that is around twice as much gas transportation as necessary to serve the CTs. To the extent that CEI South proposes to overcharge captive electric customers in order to protect the size of its gas utility customer base or usage base, this is unlawful cross-subsidization that the Commission cannot countenance.

We have consistently rejected utility attempts to force captive ratepayers to cross-subsidize other customers. For example, in a 2010 proceeding, the Commission examined a utility's application of a customer's gas bill payment towards his electric bill balance. *In re Complaint of Michael Brenston Against N. Ind. Pub. Serv. Co.*, Cause No. 43708, 2010 WL 2095672, at *5 (Ind. Util. Regul. Comm'n May 19, 2010). We determined that this constituted unlawful cross-subsidization and warned all utilities that cross-subsidization "should be avoided at all costs." *Id.*

CEI South here has not explained whether it is concerned about preserving the size of its gas utility business more out of concern for gas distribution ratepayers or as a strategic stance to protect shareholder value. Either way, it is unjust and unlawful for electric consumers to pay, through their electric bills, for a pipeline expense that is a form of insurance for CEI South's gas interests. Despite language in the Petition that might be read as seeking approval of the Precedent Agreement with Texas Gas (*see e.g.* Petition para. 24 and request for relief q.), the Commission declines to approve here the prudence or reasonableness of the Company's Precedent Agreement with Texas Gas or the costs implied thereby. Regardless of the Commission's ultimate decision on CEI South's CPCN request for the proposed CTs, CEI South will be required to initiate another proceeding and present evidence as to the prudence and reasonableness of Texas Gas pipeline-related costs, including how much of that is properly allocable to and recoverable from electric customers, should it seek to recover those costs in the future.

The risks and costs of the pipeline contract far outweigh the purported benefits.

g. *<u>Ind. Code § 8-1-8.5-5(e).</u>*

Indiana Code § 8-1-8.5-5(e) applies because CEI South proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. That section provides that before granting a certificate to the applicant, the Commission:

> 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[.]

Subdivision (2)(e) also provides that the Commission shall consider reliability and solicitation by the application of competitive purchased power capacity and energy bids from alternative suppliers as "factors" as part of its decision. We address the elements of I.C. § 8-1-8.5-5(e) in turn below.

(1) *Are the estimated costs of the proposed facility, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable?*

First, as discussed in our analysis of I.C. § 8-1-8.5-5(b)(1), CEI South received no bids at all for single-cycle combustion turbines, and quickly dismissed the handful of other gas-fired power plant bids the Company received. Pet. Ex. 5, p. 7, ll. 10-16. CEI South did not receive any "Tier 1 bids" for gas-fired generating plants and no bids at all for CTs, CEI South instead used generic price inputs for CTs in its IRP modeling. After choosing CTs based on that generic price input, CEI South conducted exactly the same type of "unduly restrictive" RFP that we rejected in

Cause No. 45052, one that was limited to a specific technology (a 2x0 simple-cycle gas-fired combustion turbine) and a specific location (the A.B. Brown site). Pet. Ex. 7, pp. 14-15. This does not satisfy the requirements of IC § 8-1-8.5-5(e).

Second, CEI South used the same lateral sizing calculations for the 850 MW CCGT denied in Cause No. 45052 from 2018 or earlier for the 460 MWs of CTs at issue in this case. Pet. Ex. 12-R, page 10, l. 7. But, the projected cost and ownership details are completely different. Over 20 years, customers will pay over $500 million dollars for transportation rights on TGT's lateral–more than the cost of the proposed CTs and neither customers nor CEI South will even own the pipeline. By comparison, the capital cost estimated in Case No. 45052 for practically the same lateral, to be self-built by Vectren Gas, was approximately $87 million, with estimated accuracy of plus/minus 20%. Cause No. 45052, Tr. H-13, ll. 7-14. CEI South used annual figures that are oversized to demonstrate the purported need for the new lateral and mainline storage capacity, even given highly unlikely gas consumption figures. In fact, CEI South and TGT both admit the 20" pipeline option provides approaching twice the volume of gas that the CTs could possibly burn. CAC CX 9-C; Pet. Ex. 12-R at 11-12.

There is no documentation in the record on the claimed analysis by TGT. CEI South witnesses never claim to have asked for or laid eyes on any supporting documentation from TGT showing that the 16" was not viable. CAC CX 3; CAC CX 13. So the record is devoid of sufficient information to determine whether it is technically feasible to deliver gas at 600 psi via 16" pipeline, as demonstrated by TGT proposed lateral, which reaches the AB Brown site in exactly that manner. *Cf*. CAC CX 7; Tr. D-21 to D-23. CEI South did not provide any other analytical documentation showing that any other supply configurations were feasible or preferable, besides the 20" lateral pipeline, i.e. the 45052 pipeline analysis. Thus, options, including but not limited to a 16" pipeline or conjoining capacity with Dogtown lateral, were never shown to have been adequately explored. CEI South has not been clear either about what other options have been evaluated when it comes to options for gas transportation service, so the Commission cannot make the most educated decision possible about what the most cost-effective decisions available to the Company are. We cannot find that the pipeline was competitively bid when CEI South used improper sizing, especially when the record shows the original TGT proposal included a 16" pipeline option, at a discount before it was revised after discussions with CEI South. CAC CX 10-C. Captive customers should not overpay for capacity that is not as closely sized to the maximum need as possible.

CEI South, on behalf of its customers, committed to all that supply from a 20" pipeline, on the logic that since the price offered was the same, they might as well contract for twice as much. CAC Cross. Ex. 8; Tr. at C-51, l. 18 - C-52, l. 7. However, we are unable to ascertain whether CEI South's contention is correct because of the failure of form in which CEI South bid the pipeline.

CEI South never conducted a formal RFP for pipeline services, rather its verbal informal RFP was conducted over the phone. Tr. C-14, ll. 14-21; D-4, l. 25 - D-5, l. 1. We are troubled too that CEI South gave conflicting information as to what the flow rate (in MMBtu/hour) required for the proposed CTs is. The informal RFP considered pipelines to fuel H-Class turbines, despite the fact that CEI South had already decided months earlier to go with F-Class turbines. Ms. Grizzle, who conducted the informal RFP phone call, testified that she had not been informed the gas turbine would be F-Class (Tr. C-44, ll. 1-7) although the Director of Indiana Electric Regulatory and Rates thought it a "fair assumption" she was. Tr. H-16.

CEI South also made no efforts to defray costs in its bidding of the pipeline, making seriously questionable decisions in terms of competitive bidding strategy. The open season for additional bidders for gas capacity on the proposed TGT lateral lasted just one week over major winter holidays, and—unsurprisingly—no additional bids were received. Tr. D-7 at ll. 2-16.

CEI South presented no evidence that it reasonable explored alternative routes for the pipeline or meaningfully evaluated smaller and potentially more cost-effective firm gas transportation options.

Most importantly, particularly in the absence of a formal RFP, we are concerned that CEI South did not try to negotiate rates at all with TGT. Tr. C-48 - C-49. Although CEI South emphasized the contract with TGT would provide no-notice service, this aspect of gas delivery is unrelated to the physical design of the pipeline proposed by TGT. In other words: CEI South did not need to pay for such a large pipe to secure priority for gas delivery. Tr. C-15 at ll. 5-12.

Based on the foregoing, we find that CEI South has not met its statutory burden of demonstrating that the estimated project costs are the result of competitively bid engineering, procurement and construction contracts.

(2) *Did the applicant allow or will it 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?*

Since CEI South is a public utility that was furnishing retail electric service to customers in Indiana on January 1, 2011, it qualifies as an "electricity supplier" as defined in I.C. § 8-1-37-6. As noted above, CEI South's proposal for a gas pipeline is even costlier than what we rejected in Cause No. 45052, and neither CEI South nor its captive customers would even own the pipeline. Here, over 20 years, customers will pay over $500 million dollars for transportation rights on TGT's lateral–more than the cost of the proposed CTs and neither customers nor CEI South will even own the pipeline. By comparison, the capital cost estimated in Case No. 45052 for practically the same lateral, to be self-built by Vectren Gas, was approximately $87 million, with estimated accuracy of plus/minus 20%. Cause No. 45052, Tr. H-13, ll. 7-14.

(3) *Reliability and solicitation of energy and capacity purchases as alternatives (Ind. Code § 8-1-8.5-5(e)(2)).*

Because the proposed facilities will have a generating capacity of more than eighty (80) megawatts, Indiana Code § 8-1-8.5-5(e) also directs us to consider reliability as a factor in determining whether CEI South has demonstrated the public necessity and convenience will be served by construction of the proposed CTs. The North American Electric Reliability Corporation (NERC) defines reliability of the North American bulk power system with respect to (1) the "ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times" (adequacy); and (2) the "ability of the electric system to withstand sudden disturbances" (operating reliability).[15] CEI South assures adequacy by meeting MISO reserve margin planning requirements, either through ownership of resources, power purchase agreements, or capacity purchases. CEI South has also emphasized aspects of operating reliability, such as maintaining transmission system voltage. But CEI South cannot single-handedly ensure the reliable operation of MISO's grid, including the integration of renewables—in fact, maintaining voltage support, and other grid services are primarily the responsibility of MISO—and CEI South should not burden its ratepayers with nearly $1 billion in new generation in an attempt to do so.

The Commission finds that CEI South overstated risks related to resource adequacy, particularly prior to 2028 (when new long-lead time projects, such as CTs, could be installed after their next IRP, incorporating technological developments and the proposed MISO seasonal construct), and that CEI South can maintain its share of the resource adequacy responsibility without taking on the substantial and long-term financial risk of constructing 460 MW of new gas generation. To the extent there are operational reliability issue at stake in this proceeding, those concerns do not justify the magnitude of the cost at issue.

Resource adequacy. All parties agree that the generation mix on the MISO grid is changing rapidly and there is significant uncertainty as to how the grid will change over the life of the proposed CTs. CEI South will conduct an IRP beginning this year and that CEI South will be able to install any generation identified as part of that IRP process by 2027. The Commission therefore focuses here on the period between 2024 (the earliest date the proposed CTs could begin operation) and 2027 to assess the importance of the proposed CTs for resource adequacy. The Commission rejects the CTs proposal because CEI South has proposed a plan to comply with its MISO reserve margin requirement that is high cost and entails the creation of significant long-term risks for customers, all to avoid a near-term risk that appears quite manageable: pursuing other components of its 2019-2020 IRP plan, including purchasing short-term capacity, to maintain the utility's flexibility as it undertakes a new IRP in the face of changing market conditions.

As an initial matter and as discussed above, modeling introduced by intervenor CAC suggests CEI South may have the ability to achieve at least 227 MW of demand response with its current customer base. CEI South improperly modeled demand response as part of its IRP and ignored the 50 MW DR bid in response to its all-source RFP when designing its candidate portfolios. Thus, when reasonable estimates of demand response are incorporated into CEI South's capacity projects, CEI South could have already secured all but approximately 200 MW (430 MW of two CTs minus 227 MW of demand response) of the capacity needed that would have been provided by the two proposed CTs to meet MISO's reserve requirement during 2025/2026, 2026/2027, and 2027/2028. Even without adjusting CEI South's *load* projection, we find it is able to meet its resource adequacy requirements without taking on the stranded asset risk of the proposed CTs.

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[15] Pet. Ex. 5-R, Workpaper MAR-3 (NERC, *State of Reliability* (August 2021), available at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2021.pdf), at 2

Although CEI South made much of the need to provide electricity when "the sun is not shining and the wind is not blowing," *e.g.* Pet. Ex. 5-R at 46, these characteristics of solar and wind output are already accounted for by MISO in its ELCC accreditation for wind and its accreditation of solar generation. The ELCC (Effective Load Carrying Capability) incorporates weather-related limitations on renewable generation by only accrediting these resources at a percentage of their nameplate capacity when assessing whether a utility has met its planning reserve margin requirement. As discussed above, we find that CEI South undervalued the solar and wind generation it has already installed or is planning to install based on its 2019/2020 IRP relative to MISO's own forecasts about how it will value wind and solar going forward. The 2019 MTEP anticipates solar accreditation will decline from its current value of 50% of installed capacity beginning in 2023 at approximately 2% per year. (We note that this forecast is based on levels of solar penetration that are higher than has actually been realized in the MISO grid.) SC Ex. 1 at 30; CAC Ex. 2 at 26-27. Properly accrediting capacity to solar resources, by using the MISO projection instead of CEI South's, adds 150 MW to CEI South's total accredited capacity for purposes of MISO's resource adequacy requirement for 2026/2027 planning year.[16] We credit the MISO forecast of solar accreditation decline, even noting that the solar penetration today is lower than the MISO forecast relied on by CAC witness Sommer and Sierra Club witness Goggin, so this is a conservative estimate. Thus, with the corrected load and corrected MISO forecast of solar accreditation decline, CEI South would only need to "replace" about 50 MW of accredited capacity from the two proposed CTs for the 2026/2027 planning year.

Similarly, although CEI South assumes its proposed wind generation will have an initial ELCC credit of 7.2% declining to 7.1% in the planning year 2027/2028, these estimates are based on out-of-date ELCC estimates using old technology. But as Sierra Club witness Goggin observed, those figures are based on installed wind projects in Indiana that are older technology than modern turbines. SC Ex. 1, pp. 32-35. It is reasonable to assume that modern turbines achieve ELCC accreditation that is higher than that 7.1% figure, especially, for winter, if MISO's proposed seasonal capacity construct is implemented.[17] By applying the higher ELCC number that is more-consistent with modern turbine technology, the Company should receive an extra 15 MW[18] of accredited capacity, at a minimum, from its wind project. This reduces the need to "replace" capacity that would have been provided by the two proposed CTs to around 35 MW.

In short, the Commission finds that, relying on MISO forecasts for wind and solar accreditation, CEI South's estimate of needed capacity in the near-term is double what is actually necessary to fulfill its obligations under the MISO tariff and thus to meet its resource adequacy

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[16] CenterPoint's assumes 835 MWs of nameplate solar by planning year 2026/2027. *See* Pet. Ex. 11-R, p. 8. At the MISO 2019 MTEP projected ELCC for that planning year, which is 43% (SC Ex. 1 at 30-31), those MWs of solar equate to 359.1 MW of accredited capacity. CenterPoint's projected ELCC for that planning year of 25% (*see* IRP Figure 8-7) would instead produce 208.8 MW of accredited capacity. The difference is 150.3 MW of extra capacity than CenterPoint is assuming, based on the MISO projections.

[17] MISO's proposed seasonal capacity market and seasonal capacity accreditation have been proposed in the pending FERC Docket No. ER22-495.

[18] 200 MW of wind at an ELCC of 7.1% equates to 14.3 MW in planning year 2026/2027. 200 MW of wind at an ELCC of 16.3% of equates to 32.6 MW in planning year 2026/2027.

reliability obligations. These adjustments alone eliminate the need for one of the proposed CTs, at least through 2028.

For the remaining amount of capacity, around 35 MW, CEI South has several options. One option would be to purchase more short-term capacity than what CEI South has currently purchased. Evidence shows that near-term capacity is available at a reasonable price that is at or lower than the 2019-2020 IRP's forecasted price. Further, as we found in the Co-ownership section, the actual price paid for short-term capacity prior to 2027 is far lower than the capacity cost of the proposed CTs. And, unlike the proposed CTs and proposed pipeline, there is little long-term risk associated with relying on capacity purchases. They are one-year only contracts. If capacity purchases become more expensive than expected in 2026-2027 and 2027-2028, then the Company could respond by building more of its own resources as a result of this next IRP or the subsequent one. It makes no sense for customers to pay a significant premium and take on long-term risk, as CEI South proposes here, only to avoid the possibility of a manageable short-term risk.

CEI South speculates that capacity prices for short-term purchases might significantly increase, but we are persuaded by CEI South's own capacity contracts for this near-term that increases of the magnitude CEI South identifies are unlikely. Moreover, and as discussed above, even the projected bilateral capacity prices for future planning years are less than the capacity cost of the proposed CTs, and capacity clearing prices through the Planning Resource Auction have historically been far lower than that. CEI South also cites the OMS-MISO Survey to assert that MISO anticipates a capacity shortfall by 2024. But this Survey includes unconfirmed retirements. If only firm retirements are counted, "MISO would be resource sufficient throughout the period." NERC LTRA at 59. According to NERC, "sufficient capacity is expected when considering all prospective capacity contributing to the prospective reserve margin in the 2021 LTRA even with a shift from baseload generation to ever increasing [variable energy resources]." *Id.* As both Sierra Club witness Goggin and CAC witness Sommer point out, MISO has previously predicted capacity shortfalls that did not arise, and MISO Zone 6 had more than 4,000 MW of unutilized import capability in the most recent Planning Resource Auction. SC Ex. 1, p. 18, l. 19—p .19, l. 2; CAC Ex. 2, p. 58, ll. 2-9. What CEI South characterizes as a reliability risk is actually a financial risk: whether CEI South can obtain sufficient energy and capacity on a yearly forward-going basis to ensure service during periods of renewable non-generation from existing resources on the grid at more or less cost than generating it itself. CEI South's theory that capacity prices might increase significantly in the mid-to-late 2020s is not supported by the record, which shows that the capacity remains relatively cheap in every year for which CEI South has sought bids.

A further option for MISO accredited capacity would be to install some batteries, perhaps at the A.B. Brown site or even closer to load. CEI South's 2019-2020 IRP called for some solar plus storage, including 126 MW of batteries in 2023, but CEI South has not yet proposed any storage. As prices for batteries continue to decline, this could represent an attractive option, in part because batteries have a very high capacity accreditation, can be deployed rapidly, and in many locations. Like Demand Response, batteries can be rapidly deployed if CEI South's load forecast unexpectedly increases or MISO reduces the ELCC for solar or wind beyond what it currently predicts or if short-term capacity prices do significantly increase.

In sum, we find that CEI South has overstated both the gap between its current and planned generation and MISO resource adequacy requirement and the financial and reliability risk associated with closing that gap through other available options, such as short-term capacity purchases, installation of batteries, or deployment of Demand Response. Conversely, we find that construction of 460 MW of gas-fired generation with an economic life of 20 years or more presents financial risks to ratepayers far out of proportion to the resource adequacy benefit these units offer in the near-term. CEI South will be better positioned to make informed decisions about medium- and long-term resource adequacy in their 2022/2023 IRP in light of rapid technological development and the implementation of a seasonal capacity construct by MISO.

Operational Reliability. CEI South's witnesses repeatedly claimed that the proposed CTs are required to maintain reliability in periods of low or no generation by wind and solar resources. This issue is almost exclusively covered by MISO in its accreditation of wind and solar resources, as a resource adequacy question. To the extent that CEI South argues this is an operational reliability issue, its concerns in this area are ill-defined in the record, and MISO is ultimately responsible for ensuring grid services are in place for a reliable grid, in conjunction with the many state commissions and utilities and other stakeholders. To the extent CEI South intends to suggest that CEI South must be able to generate electricity to meet its own demand at all times, this ignores the existence of the MISO energy and capacity markets and misstates the architecture of the North American grid. As CEI South witness Bradford testified in a prior proceeding, although a bulk electric system will need to adapt when a large portion of *system-wide* annual load is served by renewable generation, these issues do not apply at the individual utility level. *S. Indiana Gas & Elec. Co. d/b/a Centerpoint Energy Indiana S. (Centerpoint)*, No. 45501, 2021 WL 5052376, at *22 (Oct. 27, 2021).

CEI South is not a grid operator. MISO is the operator, as overseen by FERC. Although the Commission agrees with CEI South and NERC that "transformative thinking" is required to address the integration of variable resources into the grid, that transformative thinking can only be accomplished at the system level, and it is *system* operators who must have access to flexible resources. As discussed above, CEI South has not demonstrated that the price signals in the MISO market show a need for increased gas generation to accomplish these goals in the near term. We decline to burden customers with an investment of this magnitude given the medium-term uncertainty, especially when CEI South can meet its resource adequacy obligations as a MISO participant through relatively low-cost alternative measures.

We find that CEI South's proposal to meet its resource adequacy obligations through two CTs is high cost and high risk compared to many other viable alternatives. CEI South is in the process of, and can continue, obtaining the needed capacity with less stranded asset risk through going forward with other components of its 2019-2020 IRP preferred plan, capacity purchases, expanded Demand Response programs, and storage. CEI South's concerns with operational reliability are not concretely at issue here, and certainly do not justify the magnitude of investment in a single fuel source that they have proposed given the other lower-cost, low risk options available for meeting its resource adequacy obligations. As we stated in Cause No. 45052, "The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime." *Cause No.*

45052, 2019 WL 6770066 at *22. CEI South has failed to justify this risk in light of the alternatives—including demand-side alternatives—available to it.

iv. Conclusions regarding CPCN for new CTs.

CEI South is correct that not all intervenor parties agree what provides the best option for meeting CEI South's capacity needs between now and its next IRP. But far from supporting CEI South's proposal—which would commit close to $1 billion in ratepayer funds to a 460-MW facility dependent on an unapproved pipeline—the very diversity of options available argues against approving such a huge sunk cost at a time where *all* parties agree flexibility is required. As discussed at length above, we find that CEI South understated the capacity value of solar and wind resources and made significant errors in its modeling of batteries; has failed to develop meaningful demand response programs that could reduce its customer load at minimal cost; has projected load increases that are at odds with past trends; overridden the results of its own IRP risk modeling by overweighting the relative risk of capacity price increases to gas price increases; failed to meaningfully consider refurbishment of the existing A.B. Brown turbines as an alternative to new construction; entered into a 20-year contract term for gas supply without a fully competitive process and based on a different model of turbine than actually proposed; and ignored the results of the all-source RFP we urged in Cause No. 45052 by selecting a type of generation for which it did not actually receive any competitive bids.

CEI South's proposes to commit to 20 years or more to having more than a third of its capacity come from a carbon emitting technology. Given the present uncertainties about the future of carbon emitting technologies in the U.S. and world economies, such a heavy long-term bet on natural gas presents material downside risk to its customers, should things not go as anticipated, either with respect to carbon emissions or natural gas prices and availability.

Considerable uncertainty exists as to both the cost of fossil fuel infrastructure and the availability of alternatives ten, five, or even one year from now. But from the information available to us as regulators we do know that many people and companies are putting significant effort into finding less expensive ways to supply energy without emitting greenhouse gasses. So, without clear evidence to the contrary (which the Company's modeling evidence does not provide), we are reluctant to approve CEI South having most of its generation capacity tied to a greenhouse emitting fuel through the 2040s. We support CEI South's desire to diversify its generation portfolio. But based on the evidence we conclude CEI South's proposed plan in fact reduces the diversity and flexibility of its generation portfolio and introduces unacceptable future risks.

CEI South seeks to commit itself, and its customers, to a generation facility primarily to address a capacity shortfall that is overstated, without meaningful off-ramps, when numerous other, more flexible alternatives, are available: battery storage, capacity purchases, and refurbishment of the current A.B. Brown site. However, CEI South's preferred CPCN plan will certainly have the highest up-front capital cost that could result in the heaviest rate impact on customers. The other alternatives all appear to have significantly lower capital costs and thus less potential for rate shock.

For all these reasons we will deny CEI South's request for a CPCN to construct two new CTs and all associated relief requested by the Company.

B. CPCN for Compliance Projects and Related Relief

Prior to granting a certificate for federally mandated requirements, I.C. § 8-1-8.4-6(b) requires the Commission to make a finding that a proposed compliance project will allow the utility to comply with one or more federally mandated requirements.

In Cause No. 45052, in which we rejected CEI South's request for a CPCN to construct new combined cycle combustion turbine capacity, CEI South claimed that CCR regulations made it impracticable to continue operating its coal-fired fleet beyond 2023. *Cause No. 45052*, 2019 WL 6770066 *3. However, in the interim, the EPA amended its CCR regulations to create new regulatory opportunities to extend the deadline to cease CCR disposal into the AB Brown unlined ash pond. 85 FR 53516; Sunrise Ex. 2, pp. 5-22. As Mr. Nasi explained, those amendments offered CEI South two alternatives for requesting extension of its deadline to cease CCR disposal. Instead electing the alternative that would allow CEI South to operate the Brown units as long as possible provided closure of the ash pond at Brown were completed by October 17, 2028, CEI South elected the alternative that had an outside deadline of October 15, 2023 to cease disposal into the ash pond at Brown. CEI South's EPA Filing presented eight alternatives for disposal, seven of which CEI South analyzed only to determine if that alternative could feasibly dispose of the entire 8.8 MGD rather than some smaller quantity. EPA Filing, Section 5 Work Plan for Alternative Capacity (40 CFR § 257.103(f)(1)(iv)(A)(1)).

CEI South's analysis in its EPA filing seems designed to fail. Even giving CEI South the benefit of doubting that design was intentional, the analysis exhibits a failure to think outside of a "one size fits all" box. CEI South failed to recognize that it might combine multiple alternatives to achieve a feasible solution to its CCR disposal problem and thus retain the option to operate Brown units 1 and 2 longer. Additionally, as Mr. Nasi points out CEI South also had another regulatory filing alternative in which it would not have been required to analyze disposal alternatives. Instead, it could have simply committed to retire the Brown coal-fired boilers and complete closure of the ash pond at Brown by October 17, 2028. In rebuttal CEI South proffered no evidence that it analyzed the feasibility of completing closure of the Brown ash pond by October 17, 2028, or when it would need to cease operation of the Brown boilers to do so. This suggests that CEI South elected the EPA filing alternative with the earlier deadline without even studying the feasibility of filing under the alternative with the later deadline.

Regarding the Dry Fly Ash Project, CEI South previously received Commission authority to engage in beneficial reuse of its ash in Cause No. 45280. This approval came with the benefit of removal of ash from the waste stream and its subsequent use in cement manufacturing. In addition, CEI South agreed to offset the cost of the project with revenues received from the cement manufacturer. In this proceeding, CEI South seeks similar approval to install equipment that will allow it to ship dry fly ash to a customer, thereby removing the necessity for such ash to be placed in ponds. We find that CEI South's Dry Fly Ash project should be approved and note that the cost estimate provided is a Class 3, a category of estimate that provides a measure of assurance that costs will be within a reasonable range.

However, there are concerns with CEI South's other proposed projects. The OUCC's witness Ms. Armstrong testified that CEI South's proposed CCR-compliant ponds at the Brown and Culley generating plants ("Pond Compliance Project"), if approved, should come with the proviso that CEI South bear fifty percent of the cost. Her uncontested testimony showed that CEI South did not present evidence of its consideration of alternatives to the new ponds, such as retiring the Brown units by 2021. If CEI South had chosen to do so, it still would have had CCR remediation responsibilities, but not the obligation to build new ponds.

CEI South states the project will allow Brown Units 1 and 2 and Culley Unit 2 to comply with the CCR Rule, a regulation the EPA implements through its authority granted under the Resource Conservation and Recovery Act ("RCRA"). Thus, the CCR Rule qualifies as a Federally mandated requirement pursuant to I.C. § 8-1-8.4-5(3). However, CEI South's compliance plan relies on the EPA to approve an extension to allow Brown Units 1 and 2 and Culley Unit 2 to continue sending CCR material to its ash impoundments. Tr. E-9, ll. 8-11. Presently, the EPA has not yet granted CEI South's request. The OUCC's and Sunrise Coal's witnesses provided evidence that there were other CCR compliance pathways CEI South could have taken that would have provided more certainty for compliance. It is not possible to consider CEI South's pond compliance project to be federally-mandated if the federal agency charged with implementing it has not acknowledged these projects will meet the requisite standards to receive the extension to operate the ponds.

It is not the Commission's directive to determine (or assume) if CEI South has submitted a plan the EPA will approve. During the hearing, the Commission heard cross of Witness Retherford regarding the EPA's recent determinations of extension requests for other plants. Of the facilities requesting an extension request for which EPA completed its review, the EPA denied extensions for three out of the four facilities. Ms. Retherford stated the EPA's decision to deny extension requests from these three facilities revolved around whether the plant considered every possible option.

We recognize that the CCR Rule has been modified several times, but the obligation to mitigate CCR waste has been consistent. While the estimates for the Pond Compliance Project may seem reasonable, approximately $6 million for Culley and $13 million for Brown, CEI South provided a Class 5 estimate, which is based on a conceptual design and could double as engineering design progresses. Additionally, as the OUCC pointed out, CEI South did not consider or include the costs to close the new ponds. When considering the accuracy of the cost estimate along with the fact the Company is only seeking to operate these units for another 18 months, it may be more cost effective to secure capacity to meet CEI South's reliability needs than to construct the ponds. Note that CEI South will still need to secure capacity between the time the units must cease operation (October 2023) and the time its requested CTs are estimated to be in-service (mid 2024).

We also recognize that CEI South delayed its retirement decisions and is now forced to construct new ponds it might not otherwise have had to. We nonetheless find that the proposed pond costs are entirely too speculative. CEI South is still working with the EPA on conceptual designs. Tr. F- 26, l. 21 – F-27, l. 11. However, we are mindful of CEI South's obligations to comply with the CCR Rules. Therefore, we approve the ponds, subject to the following conditions precedent.

1. CEI South must provide the Commission and parties with evidence of EPA acceptance (or rejection) of CEI South's request for an extension for the compliance projects

within fifteen (15) days of receiving such notice. Any modifications of the proposed ponds as recommended by EPA should be identified with specificity, and Commission approval is required to proceed with any compliance project that is the subject of said extension.

2. To the extent that EPA approval or rejection modifies CEI South's proposed ponds, CEI South shall file a new compliance plan showing how it plans to meet the EPA's requirements.

3. Under all scenarios, CEI South shall provide an estimate for the ponds that is *at least* a Class 3 estimate, with sufficient detail to allow the Commission and all parties to review such an estimate for reasonableness.

4. CEI South shall not begin construction of the ponds until the foregoing conditions are met.

5. CEI South shall update on the progress of the Zero Liquid Discharge project.

CEI South's Class 5 estimate raises the possibility of costs doubling. This is coupled with the fact that under I.C. § 8-1-8.4-7(c)(3), a utility could recover up to 25% more than a Commission-approved estimate before having to seek additional authority. Given that CEI South's rates are already among the highest in the State, we must pay special attention to every project CEI South proposes, to ensure that the best estimate is approved. We find that this provisional approval strikes the right balance between customers and CEI South, protecting the utility's obligations while ensuring customers are not unnecessarily burdened.

C. If CEI South's CPCN for CTs is denied, request to defer costs for IRP planning and to bring this action as regulatory asset.

Finally, we turn to CEI South's request to recover the cost of its IRP and CT planning costs. CEI South is asking the Commission "in the event the CPCN for the CTs is not granted or the CTs are otherwise not placed in service, [to authorize] Petitioner 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." Direct Testimony of Steven Greeley, Pet. Ex. 1, p. 3, ll. 9-12. In support of the request, Ms. Gostenhofer stated that CEI South had "incurred significant costs that are required to conduct the planning resulting in the proposed CTs and then has incurred additional significant costs to develop the materials that are required to be submitted in this case." Pet. Ex. 9, p. 7, ll. 13-16. Ms. Gostenhofer's rebuttal testimony cited to the FERC Uniform System of Accounts ("USOA") governing costs "includ[ing] costs of studies and analyses mandated by regulatory bodies related to plant in service." Pet. Ex. 9-R, p. 8, ll. 6-8. The USOA notes that planning costs incurred for utility plant that is ultimately constructed should have such costs included as part of the utility plant's costs. *Id*.

We do not quibble with the general tenet that utilities may include the cost of planning and engineering in the estimate for utility construction. But we have not taken it as far as CEI South is requesting here: granting recovery of both IRP and planning costs, whether or not the proposed CTs are eventually constructed. While there is plenty of precedent for including planning and engineering costs in a CPCN approval, there is none when a CPCN is rejected. CEI South well knows this as a result of Cause No. 45052.

CEI South's requested recovery of these costs is through the establishment of a regulatory asset. Creation of a regulatory asset with associated carrying costs (earning a return) is premised on the theory that said asset will thereafter be placed in rates at the time of the utility's next rate case. CEI South asks us to deviate from the strictures of I.C. § 8-1-2-6, which mandates that items placed in rates be based on "tangible property", I.C. § 8-1-2-6(b), and that such property of the utility "be used and useful for the convenience of the public[.]" I.C. § 8-1-2-6(a).

While utilities have many avenues for recovery of costs incurred in the course of doing business, the general strictures of ratemaking have held that the cost must have a direct link to the provision of service to customers. Costs for bringing actions are rarely granted, with the exception of rate cases. Even then, recovery of rate case expense is subject to a review for reasonableness, because "[n]ot all expenditures are prudent and recoverable from ratepayers just because a utility claims to have incurred them." *Petition of Switzerland County Nat. Gas,* Cause No. 45117, 2019 WL 1767049 at *22 (Ind. Util. Regul. Comm'n Apr. 17, 2019), *citing Water Serv. Co. of Ind.*, Cause No. 44104, 2013 WL 1345652 (Ind. Util. Regul. Comm'n Mar. 27, 2013). And cases brought before the Commission on a regular basis, such as FACs or GCAs, do not result in the utility recovering the cost to bring the action.

Further, these are costs for which CEI South has not received prior Commission approval. Our Supreme Court recently had cause to address the issue of cost recovery absent prior approval:

> On whether Duke's past costs violate section 8-1-2-68, we turn to our precedent on retroactive ratemaking. In *[Pub. Serv. Comm'n v. City of Indianapolis*, 235 Ind. 70, 131 N.E.2d 308 (Ind. 1956)], we said that "[p]ast losses of a utility cannot be recovered from consumers nor can consumers claim a return of profits and earnings which may appear excessive." *Id.* at 315 (citation omitted). There we held that since a 1951 rate order had already been adjudicated, Indianapolis could not challenge that order as setting unreasonable rates in a 1954 proceeding. *Id.* at 309, 315. Relying in part on this precedent, the court of appeals explained in *City of Muncie v. Public Service Commission* that retroactive ratemaking includes "recoupment of actual operating losses not foreseen in the original rate-making process". 396 N.E.2d 927, 929 (Ind. Ct. App. 1979).

Ind. Ofc. of Util. Cons. Couns. v. Duke Energy Ind., LLC, --N.E.3d--, 2022 WL 713351 *3 (Ind. Mar. 11, 2022).

CEI South incurred IRP costs, as every electric generating utility does. But the incurrence of those costs, without prior approval or precedent, means that we would violate I.C. § 8-1-2-68 were we to grant the request. CEI South seeks approval in this CPCN proceeding to be granted authority to carry a past cost as a regulatory asset and later recover it in rates. Even though this is not a rate case, approving recovery of a past cost is an attempt to recover "actual losses not foreseen in the original ratemaking process[.]" *Id.*

We view our finding herein as part of our obligation under I.C. § 8-1-8.5-5(b)(3) to consider economic impacts of a utility's requested CPCN. As discussed above, CEI South's request already burdens customers with large, poorly defined costs. Adding CEI South's request to recover the costs of its IRP adds insult to injury. As part of the cost of doing business, utilities have not been granted the right to recover planning costs for unsuccessful projects, nor the blanket ability to recover the cost of every regulatory procedure. The Commission must review costs and find them reasonable and prudent to recover; a blanket approval of IRP costs after the fact does not meet that standard, as there is no Commission oversight of how a utility determines its resource needs. We therefore decline to grant CEI South the recovery of its IRP costs, as to do so would create a precedent that has not been authorized or contemplated. And because we deny the CPCN for the CTs, the planning costs are likewise ineligible for rate recovery.

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

1. CEI South's request for a certificate of public convenience and necessity under I.C. ch. 8-1-8.5 to construct two CTs providing approximately 460 MW of capacity and all associated relief requested is denied.

2. CEI South's request for a certificate of public convenience and necessity for the Dry Fly Ash Compliance Projects pursuant to I.C. ch. 8-1-8.4 and all associated relief requested is approved as described in this Order. CEI South is authorized to timely recover 80% of the approved federally mandated costs incurred in connection with the Dry Fly Ash 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. CEI South is authorized to defer 20% of the federally mandated costs incurred in connection with the Dry Fly Ash Compliance Projects for recovery in its next general rate case.

3. CEI South's request to defer the costs of bringing this action as a regulatory asset is denied.

4. CEI South's request herein for approval for CCR compliance projects is approved, subject to the following conditions precedent:

    a. CEI South must provide the Commission and parties with evidence of EPA acceptance (or rejection) of CEI South's request for an extension for the compliance projects within fifteen (15) days of receiving such notice. Any modifications of the proposed ponds as recommended by EPA should be identified with specificity, and Commission approval is required to proceed with any compliance project that is the subject of said extension.

    b. To the extent that EPA approval or rejection modifies CEI South's proposed ponds, CEI South shall file a new compliance plan showing how it plans to meet the EPA's requirements.

    c. Under all scenarios, CEI South shall provide an estimate for the ponds that is *at least* a Class 3 estimate, with sufficient detail to allow the Commission and all parties to review such an estimate for reasonableness.

d. CEI South shall not begin construction of the ponds until the foregoing conditions are met.

e. CEI South shall update on the progress of the Zero Liquid Discharge project.

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

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

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

APPROVED:

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

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Dana Kosco
Secretary to the Commission