STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH (CEI SOUTH) FOR: (1) APPROVAL OF CEI SOUTH'S 5-YEAR PLAN FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS PURSUANT TO IND. CODE CH. 8-1-39 ("TDSIC PLAN"); (2) AUTHORIZATION OF TDSIC TREATMENT AS PROVIDED IN IND. CODE CH. 8-1-39 FOR THE ELECTRIC TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (AND THE COSTS THEREOF) SET FORTH IN CEI SOUTH'S TDSIC PLAN; (3) APPROVAL OF CEI SOUTH'S USE OF ITS TDSIC RATE ADJUSTMENT MECHANISM AND RELATED ACCOUNTING DEFERRALS, PURSUANT TO IND. CODE 8-1-39, FOR THE TIMELY RECOVERY AND DEFERRAL OF COSTS RELATED TO SUCH TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (INCLUDING FINANCING COSTS INCURRED DURING CONSTRUCTION); AND (4) APPROVAL OF OTHER RELATED RATEMAKING RELIEF AND TARIFF PROPOSALS CONSISTENT WITH IND. CODE CH. 8-1-39.	**) CAUSE NO. 45894**

<u>SUBMISSION OF CAC'S EXCEPTIONS TO PETITIONER'S PROPOSED ORDER</u>

Citizens Action Coalition of Indiana, Inc. ("CAC"), respectfully submits its exceptions to Petitioner's proposed order in the above-referenced Cause to the Indiana Utility Regulatory Commission.

Respectfully submitted,

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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 12th day of October, 2023, to the following:

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CAC Exceptions to Petitioner's Proposed Order
October 12, 2023

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH (CEI SOUTH) FOR: (1) APPROVAL OF CEI SOUTH'S 5-YEAR PLAN FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS PURSUANT TO IND. CODE CH. 8-1-39 ("TDSIC PLAN"); (2) AUTHORIZATION OF TDSIC TREATMENT AS PROVIDED IN IND. CODE CH. 8-1-39 FOR THE ELECTRIC TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (AND THE COSTS THEREOF) SET FORTH IN CEI SOUTH'S TDSIC PLAN; (3) APPROVAL OF CEI SOUTH'S USE OF ITS TDSIC RATE ADJUSTMENT MECHANISM AND RELATED ACCOUNTING DEFERRALS, PURSUANT TO IND. CODE 8-1-39, FOR THE TIMELY RECOVERY AND DEFERRAL OF COSTS RELATED TO SUCH TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS (INCLUDING FINANCING COSTS INCURRED DURING CONSTRUCTION); AND (4) APPROVAL OF OTHER RELATED RATEMAKING RELIEF AND TARIFF PROPOSALS CONSISTENT WITH IND. CODE CH. 8-1-39.	**CAUSE NO. 45894**

ORDER OF THE COMMISSION

Presiding Officers:
David Ziegner, Commissioner
Wesley Bennett, Commissioner
Jennifer Schuster, Senior Administrative Law Judge

On May 24, 2023, Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner," "Company," or "CEI South") filed its petition and case-in-chief with the Indiana Utility Regulatory Commission ("Commission") requesting, among other things, authorizations and approvals for the following: (1) Petitioner's 5-year plan for transmission, distribution, and storage improvements pursuant to Ind. Code ch. 8-1-39 ("TDSIC Plan"); (2) TDSIC treatment as provided in Ind. Code ch. 8-1-39 for the electric transmission, distribution, and storage improvements (and the costs thereof) set forth in Petitioner's TDSIC Plan; (3) use of its TDSIC rate adjustment mechanism for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs of the TDSIC Plan, including financing costs incurred during construction; (4) deferral of twenty percent (20%) of approved capital expenditures and TDSIC costs of the TDSIC Plan, and interim deferrals of such costs, until such costs are reflected in CEI South's retail rates; (5) grant confidential treatment for certain confidential and proprietary information submitted in this Cause; and (6) other related ratemaking relief and tariff proposals. Petitioner's case-in-chief consisted of direct testimony, attachments and workpapers from the following witnesses:

- Richard C. Leger, Senior Vice President, Indiana Electric (Pet. Ex. 1)
- Stephen R. Rawlinson, Director of Electric Engineering (Pet. Ex. 2)
- Jason D. De Stigter, Director, Utility Investment Planning, 1898 & Co. (Pet. Ex. 3)
- Matthew R. Thibodeau, Senior Vice President and Senior Project Director, Sargent & Lundy (Pet. Ex. 4)
- J. Christopher Freeman, Manager, Corporate Security (Pet. Ex. 5)
- Chrissy M. Behme, Manager, Regulatory Reporting (Pet. Ex. 6)
- Matthew A. Rice, Director of Indiana Electric Regulatory and Rates (Pet. Ex. 7)

A Petition to Intervene filed by Citizens Action Coalition of Indiana, Inc. ("CAC") was granted by the Presiding Officers on June 13, 2023, and the CAC was made a party to this Cause.

On August 16, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") and the CAC filed their direct testimony and exhibits constituting their respective cases-in-chief. The OUCC's prefiled case-in-chief included testimony and attachments from the following witnesses:

- Kaleb G. Lantrip, Utility Analyst, Electric Division (Pub. Ex. 1)
- Gregory L. Krieger, Utility Analyst, Electric Division (Pub. Ex. 2)
- Derek J. Leader, Utility Analyst (Pub. Ex. 3)

The CAC's prefiled case-in-chief included testimony and attachments from Benjamin Inskeep, Program Director (CAC Ex. 1).

On August 29, 2023, CEI South filed its rebuttal testimony, attachments and workpapers for witnesses Rawlinson (Pet. Ex. 2-R), De Stigter (Pet. Ex. 3-R), Thibodeau (Pet. Ex. 4-R), Freeman (Pet. Ex. 5-R), Behme (Pet. Ex. 6-R) and Rice (Pet. Ex. 7-R). On September 15, 2023, Petitioner filed its response to the Commission's Docket Entry Questions dated September 13, 2023 (Pet. Ex. 9).

A field hearing was held in this matter on September 13, 2023, at 6:00 p.m. (local time) at Old National Events Plaza, Locust Room, 715 Locust St. Evansville, IN 47708. An evidentiary hearing was held in this matter on September 18, 2023, at 9:30 a.m., in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the evidentiary hearing, the prefiled evidence of CEI South, the OUCC and the CAC was admitted into the record without objection. No members of the general public appeared or participated at the evidentiary hearing.

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

1. Notice and Commission Jurisdiction. Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Ind. Code § 8-1-2-1(a) and an energy utility as defined in Ind. Code § 8-1-39-4. Under Ind. Code §§ 8-1-39-10 and 8-1-39-11, the Commission has jurisdiction over a public utility's plan for eligible transmission, distribution, and storage improvements. Under Ind. Code ch. 8-1-39 ("TDSIC Statute") and Ind. Code § 8-1-2-42, the Commission has authority over certain changes to CEI South's rates and charges. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. Petitioner's Characteristics. Petitioner is an Indiana operating public utility incorporated under the laws of the State of Indiana. Petitioner has its principal office at 211 NW Riverside Drive, Evansville, Indiana 47708. Petitioner has charter power and authority to engage in, and is engaged in, the business of rendering retail electric service within the State of Indiana under indeterminate permits, franchises, and necessity certificates heretofore duly acquired. Petitioner owns, operates, manages, and controls, among other things, plant, property, equipment, and facilities that are used and useful for the production, storage, transmission, distribution, and furnishing of electric service to approximately 150,000 electric consumers in Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick and Spencer counties.

3. Requested Relief.

By its Petition, CEI South requests the following relief:

(1) A finding that the investments contained in CEI South's 2024 – 2028 TDSIC Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2;

(2) A finding of the best estimate of the cost of the eligible improvements included in CEI South's TDSIC Plan;

(3) A finding that public convenience and necessity require or will require the eligible improvements included in CEI South's TDSIC Plan;

(4) A finding that the estimated costs of the eligible improvements included in CEI South's TDSIC Plan are justified by the incremental benefits attributable to the plan;

(5) A finding that CEI South's TDSIC Plan is reasonable;

(6) Approval of CEI South's TDSIC Plan;

(7) Authorization of TDSIC treatment as provided in Ind. Code ch. 8-1-39 for the eligible transmission, distribution, and storage improvements included in the Plan, through CEI South's existing TDSIC rate adjustment mechanism,

which was approved in this Commission's September 20, 2017 Order in Cause No. 44910;

(8) Approval of the use of Petitioner's TDSIC rate adjustment mechanism for timely recovery of 80% of the approved capital expenditures and TDSIC costs of the TDSIC Plan, including allowance for funds used during construction ("AFUDC"), post-in-service carrying costs ("PISCC"), projected and annualized property tax and depreciation expense, and amortization of deferred depreciation expense, plan development costs, and PISCC;

(9) Authorization of the deferral of 20% of the approved capital expenditures and TDSIC costs for the TDSIC Plan, including depreciation, AFUDC, and PISCC for recovery as part of its next two general rate cases; and

(10) Authorization to utilize interim deferrals related to the recovery of 80% of approved capital expenditures and TDSIC costs of CEI South's TDSIC Plan, which will be recovered via the TDSIC rate adjustment mechanism, until such costs are reflected in rates via the TDSIC rate adjustment mechanism or in base rates.

(11) Approval of other related ratemaking relief and tariff proposals.

4. Evidence Presented.

A. CEI South's Case-in-Chief. CEI South witness Leger testified that CEI South's first TDSIC plan, approved in Cause No. 44910 (the "44910 TDSIC Plan"), was a seven-year plan that expires on December 31, 2023. He stated CEI South is on track to complete the committed scope within the $446.5 million program cap established in Cause No. 44910 in the second half of 2023. Mr. Leger explained the TDSIC Plan proposed in this Cause is needed to fulfill CEI South's obligation to continue providing effective, safe, and reliable electric service to its customers. Pet. Ex. 1 at 5. CEI South witness Rawlinson summarized what CEI South has accomplished through its investments under the 44910 TDSIC Plan. Pet. Ex. 2 at 5-6. Mr. Rawlinson described the reduction of risk achieved through completion of projects in the 44910 TDSIC Plan. *Id.* at 17-19. He explained, however, there is an ongoing need for CEI South to undertake new and replacement capital investment for purposes of safety, reliability, and system modernization. *Id.* at 7.

i. Overview of Plan.

Mr. Leger and Mr. Rawlinson both testified that the five-year TDSIC Plan, covering the period of January 1, 2024 through December 31, 2028, consists of approximately $454 million in proposed investments across seven different Programs: (1) Distribution 12kV Circuit Rebuild, (2) Distribution Underground Rebuild, (3) Distribution Automation, (4) Wood Pole Replacement, (5) Transmission Line Rebuild, (6) Substation Rebuild, and (7) Substation Physical Security. Pet. Ex. 1 at 6; Pet. Ex. 2 at 8. Mr. Leger and Mr. Rawlinson explained that the improvements, upgrades and, in some cases, new technologies and/or approaches included in the TDSIC Plan have been carefully selected by CEI South to preserve and further enhance system safety, reliability and resiliency with an aim of reducing the likelihood of equipment failures and unplanned outages. Pet. Ex. 1 at 6; Pet. Ex. 2 at 7-8. Mr. Leger testified that overall safety and reliability are improved by replacement of aging infrastructure to address the causes of outages, equipment failures, and interruptions in service, while the enhanced controls around distribution and transmission lines and substation equipment described in the TDSIC Plan will enhance safety. Pet. Ex. 1 at 6.

Mr. Leger provided an overview of the benefits generated by the TDSIC Plan, including enhanced reliability, resiliency and safety and stated all customers benefit from avoiding interruptions or reducing the duration of a service interruption. *Id.* at 8. He testified that the TDSIC Plan will strengthen CEI South's electric system and prepare it to meet customers' future expectations and needs. Even during outage events, Mr. Leger explained the Programs in the TDSIC Plan will improve the system's ability to serve customers and the overall customer experience by improving identification and isolation of outages and improved restoration times and accuracy regarding estimation of restoration times. *Id.*

Mr. Rawlinson testified that while CEI South has worked hard to maintain the system and reliably meet the needs of customers, the Company also understands more must be done to improve the region's energy infrastructure to meet the requirements of a transforming electric grid. Pet. Ex. 2 at 3. He testified that the transition to renewable generation resources, electrification, and FERC Order 2222 will transform the way the grid is utilized in the coming years and therefore the Company must prepare its transmission and distribution assets to accommodate renewable generation, Electric Vehicles ("EV"), and Distributed Energy Resources ("DER"). *Id.* at 3-4.

Mr. Rawlinson explained that the TDSIC Plan is presented and organized at both the programmatic and a project level so that it can be viewed in different ways. It can be viewed by investments across programs and projects; program type and the projects within each program; and by year. Pet. Ex. 2 at 10. He outlined each of the programs in the TDSIC Plan as follows (Pet. Ex. 2 at 11-12):

Distribution 12kV Circuit Rebuild Program: This Program includes the replacement of: (a) obsolete and aged conductors, within a protection zone, with higher capacity and stronger aluminum cables, (b) aging wood poles with poles based on current, more robust material standards, and (c) other hardware and equipment as needed to satisfy current engineering and material standards designed to improve reliability. In addition, CEI South will incorporate looping (circuit ties) with modern switches, where applicable, that will improve grid resilience by providing alternate feeds for reenergizing customers during extended outages.

Distribution Underground Rebuild Program: This Program involves the replacement of deteriorating underground ("UG") bare concentric neutral cable with jacketed cable. The Program also includes the replacement of aged conductors, within a protection zone, with conductor that meets current engineering and material standards. In addition, CEI South will incorporate looping that will improve grid resilience by providing alternate feeds for reenergizing customers during extended outages.

Distribution Automation ("DA") Program: This Program consists of installing DA capable equipment to allow automatic switching of customers during an outage event. This type of equipment can be opened and closed remotely from CEI South's Control Room allowing for reduced mobilizations to return the system to normal conditions. The Program includes new reclosers, communication devices, and other supporting equipment. The associated communication and automation can be leveraged in the future to enable more complex schemes to manage the evolving distribution system to accommodate EVs and DERs.

Wood Pole Replacement Program: This Program includes a wood pole treatment and replacement program that utilizes inspection data of approximately 11,000 poles annually with the flexibility to address urgent and emergent situations as those are identified.

Transmission Line Rebuild Program: This Program involves rebuilding aging transmission line sections to reduce the risk of failure, taking into consideration future communication and capacity needs. Projects can include reconductoring, wood to steel pole conversions, and Optical Ground Wire ("OPGW") installation. The deployment of OPGW (or fiber optic communications) facilitates substation to substation and substation to control center communication, and is used in a variety of communications use cases including high-speed protective relaying, SCADA, and backhaul for corporate network traffic from power generation locations, service centers, substations, etc.

Substation Rebuild Program: This Program consists of rebuilding and replacing obsolete and/or end of life substation equipment. Assets replaced include transformers, breakers, relays, communications, and others. Modernized substation engineering designs and material standards facilitate both flexibility and optionality to manage a modern grid.

Substation Physical Security Program: This Program addresses the evolving security threat at CEI South's substation facilities by investing in additional security measures.

CEI South witness Freeman described in testimony the addition of various security monitoring control technologies and fencing to substations. He explained that the specific controls being added at each site have been determined based on the criticality rating of each substation. The controls include tools to deter, delay, detect, and report substation intrusions. Pet. Ex. 5 at 2. Mr. Freeman emphasized that unauthorized entry into a substation is commonly associated with criminal activity related to theft of materials onsite, theft of copper components, gaining unauthorized access to industrial control or cyber systems, or sabotage of equipment on site. He testified that unauthorized entry can result in damage to station components resulting in a service outage and/or resulting in increased risk to authorized personnel on site. Mr. Freeman explained that unauthorized entry presents a significant risk of severe injury or death to the intruder due to contact with live electrical components. Any issues caused in the substation due to an intrusion can ultimately result in electric service reliability issues for customers. *Id.* at 3.

Mr. Freeman testified that the threat of physical attack on the electric grid has increased in the past few years. *Id.* at 4. He gave examples of recent articles reporting on Department of Homeland Security warnings of domestic violent extremists who "have developed credible, specific plans to attack electricity infrastructure since at least 2020, identifying the electric grid as a particularly attractive target." Pet. Ex. 5 at 4 (citing Brooks, C., *3 Alarming Threats To The U.S. Energy Grid – Cyber, Physical, And Existential Events*, Forbes (Feb. 15, 2023), *available at* https://www.forbes.com/sites/chuckbrooks/2023/02/15/3-alarming-threats-to-the-us-energy-grid--cyber-physical-and-existential-events/?sh=6e7e871c101a.) He also cited a recent notable attack in North Carolina, when two substations were shot at, causing transformer damage. The damage to the transformers left more than 40,000 people without electricity for multiple days. This created multiple issues for the area requiring opening shelters, closing schools, declaring a state of emergency, and issuing a nightly 9pm curfew. Pet. Ex. 5 at 4 (citing Lavigne, L. "State of Emergency Declared in Moore County after power substations hit with gunfire," WRAL.com (Dec. 4, 2022), *available at* https://www.wral.com/state-of-emergency-declared-in-moorecounty-after-power-substations-hit-with-gunfire/20613409/).

Mr. Freeman outlined in confidential testimony the details of the full security monitoring controls that are being added and the locations at which they will be installed. Pet. Ex. 5 at 5. He also described the upgraded fencing controls being added at certain locations. *Id.* at 6. He described basic intrusion monitoring controls being added as well. *Id.* at 6.

Mr. Rawlinson testified that CEI South will require the ability to move projects already within the five-year Plan timeline, as well as remove, adjust, or add projects. As explained in more detail below, CEI South will provide details on any updates to its Plan in its semi-annual tracker filings. Pet. Ex. 2 at 13. The TDSIC Plan provides a list of all proposed projects, a unique project identifier (work order number), a short project description, the planned year of construction, the estimated cost of the project, the location of the project, and the program to which it belongs. As CEI South implements the TDSIC Plan, the exhibit will be updated semi-annually to identify changes to applicable projects, such as timing (year) or cost (estimate). *Id.* at 16. He testified that while CEI South has developed a detailed TDSIC Plan that identifies specific projects to be completed in specific years, CEI South recognizes the need for flexibility within the Plan as paramount, to stay responsive to changing risks to the ever-evolving electric system and to maximize the investments the Company is proposing. CEI South will evaluate and, as needed, reprioritize the proposed projects within the planned years and update the TDSIC Plan in the semi-annual filings to reflect any changes needed. In addition to moving projects within the five-year Plan as system needs change, Mr. Rawlinson testified that it is also important to have the ability to move a project into the five-year Plan from the Potential Substitution Project ("PSP") list. The PSPs may be selected to move into the Plan as an output of the Company's constant assessment of the electric grid and its associated risks. Mr. Rawlinson stated the PSPs underwent the same engineering and estimating process as the projects in the five-year Plan. *Id.* at 20. He described the types of projects listed as PSPs. *Id.* at 20-21.

Mr. Rawlinson testified that the eligible improvements included in the 2024 – 2028 TDSIC Plan are required or will be required to maintain the safety, integrity, and reliability of CEI South's transmission and distribution systems consistent with the public convenience and necessity. *Id.* at 37.

ii. Plan Development.

Mr. Leger described the process CEI South undertook to develop the 2024 – 2028 TDSIC Plan, working with 1898 & Co. ("1898") to employ an objective-driven decision-making approach and then performing a quantitative and qualitative evaluation for each investment. Pet. Ex. 1 at 6-7.

Mr. Rawlinson testified that CEI South, in collaboration with 1898, identified and prioritized potential Programs and associated Projects that meet the following goals: maintain and enhance CEI South's grid reliability and resiliency, manage life-cycle investments from aging equipment, and modernize CEI South's grid for long-term customer benefit while continuing to deliver service safely. Upon identification, Mr. Rawlinson said the Programs and associated Projects were subjected to a screening process to validate they met the requirements of the TDSIC Statute. He testified that this process ensured that each Program met the eligibility criteria of new or replacement transmission or distribution projects and defined purposes such as safety, reliability, system modernization or deliverability ("TDSIC Purposes"). He explained that further analysis and review ensured that CEI South could provide necessary estimates and cost benefits. Lastly, Mr. Rawlinson explained that CEI South considered whether each proposed Program met criteria including sufficient detail, the extent to which they produced incremental benefits, and were unique and feasible. Pet. Ex. 2 at 13-14.

Mr. Rawlinson testified that that in general, CEI South's Engineers, Planners, Field Operations, and System Operations reviewed the qualifying list of projects for prioritization based on known field conditions, outages, and load growth. He said multiple protection zones were then rolled into a single Project to align with current construction practices. According to Mr. Rawlinson, this consolidation was performed to gain productivity from reduced mobilization and demobilizations of the workforce when work is grouped together at the same location. Projects were then reviewed to identify, with a high level of confidence whether the project could be executed as proposed. A portfolio of Programs and corresponding Projects was then prioritized to develop the specific improvements included in the Plan and schedule for executions in a logical and efficient manner. Pet. Ex. 2 at 14.

Except with respect to select projects that could not go through the Risk Model because there were either no assets being replaced or the asset was being replaced for deliverability instead of reliability, include distribution substation expansions, capacitor banks rebuild/installation, and 12kV rebuilds for new circuits, Mr. Rawlinson testified that all Projects that were identified by the 1898 & Co.'s AssetLens Analytics Engine ("Risk Model") and included within the Plan were selected based on a benefit to cost ratio ("BCR") of 1 or greater. Pet. Ex. 2 at 14-15.

Mr. Rawlinson confirmed that none of the TDSIC Plan investments and costs are currently reflected in CEI South's rate base in its most recent base rate proceeding (Cause No. 43839, Order issued April 27, 2011). Pet. Ex. 2 at 16.

Mr. De Stigter explained the purpose of the objective-driven decision-making approach employed in development of CEI South's TDSIC Plan is to identify and align investments to CEI South's Plan Objectives (Deliver Service Safely, Maintain Reliability & Resiliency, Manage Asset Lifecycles, and Modernize the Grid) and TDSIC Purposes (Safety, Reliability, Economic Development, Modernization). As part of this approach, he said 1898 & Co. developed a business case value framework to measure an investment against achieving the Plan Objectives. Pet. Ex. 3 at 3. Mr. De Stigter explained that the business case value framework includes both quantitative and qualitative value drivers for each investment. Each of the value drivers is directly linked to one of the CEI South Plan Objectives and indirectly to one or more TDSIC Purposes. For the quantitative evaluation, 1898 & Co. utilized a risk and resiliency-based planning approach to provide a business case for each investment. Mr. De Stigter said the evaluation leverages 1898 &

Co.'s AssetLens Analytics Engine (also referred to as the "Risk Model"), an asset investment planning tool to evaluate the life-cycle benefits of replacing transmission and distribution infrastructure and deploying smart devices across the distribution system. *Id.* at 4. The business case evaluation employs a data-driven, bottoms-up methodology utilizing robust and sophisticated analytics to calculate the risk and resiliency benefit of investments. Pet. Ex. 3 at 4.

1898 & Co. and CEI South prioritized the investments into the Plan to provide the most value to customers after accounting for CEI South execution constraints. Pet. Ex. 3 at 4. For the investments identified using this quantitative approach, the business case also included qualitative factors as additional benefit streams. Mr. De Stigter testified that approximately 81.2 percent of the Plan investment level was developed using this approach. *Id.* at 4-5. He went on to explain that CEI South also identified investments based on other system needs. These investments were identified by CEI South planning, engineering, field operations, and maintenance teams ("CEI South System Stakeholders"). The business case for these investments is based on their alignment to CEI South Plan Objectives and TDSIC Purposes. According to Mr. De Stigter, approximately 18.8 percent of the Plan was developed using this approach. He testified that many of these investments are needed to manage safety risks and to continue to deliver electric service. *Id.* at 5.

Mr. De Stigter testified the customer is the central focus of CEI South's TDSIC Plan. He then described the four main customer-centric objectives for the Plan: Deliver Service Safely, Maintain Reliability & Resiliency, Manage Asset Life Cycle, and Modernizing the Grid. Pet. Ex. 3 at 8-9. He explained how these objectives align with the TDSIC Purposes identified in the TDSIC Statute, and how each of the investment programs in the TDSIC Plan align to CEI South's objectives as well as TDSIC Purposes. *Id.* at 10-12. Mr. De Stigter described in detail the high-level value framework approach 1898 & Co. and CEI South adopted to identify, prioritize, and justify investments. *Id.* at 13-14.

Mr. De Stigter testified that CEI South and 1898 & Co. also identified PSPs from the risk and resiliency analytics project identification approach. He stated these PSPs each had quantified benefits that justified the cost. Given the uncertain nature of project execution and unknown challenges, Mr. De Stigter testified the PSPs provide CEI South needed execution flexibility as realities outside of CEI South's control cause changes to the execution of the TDSIC Plan. One example Mr. De Stigter provided is supply chain issues with power transformers that may cause a delay in substation projects. Pet. Ex. 3 at 16.

iii. TDSIC Plan Benefits.

Mr. Rawlinson described the benefits of the TDSIC Plan in detail. He explained that the Programs in the TDSIC Plan are designed to strengthen CEI South's electric system and prepare the system to meet customers' future expectations and needs. Some of the main benefits of the TDSIC Plan include reduction in number and duration of unplanned outages, as well as overall improvements to system reliability and safety through the replacement of aging assets, improved deliverability, and enhanced abilities to monitor real time system performance. Additional benefits include improved system ability to serve customers even during outage events, quicker identification and isolation of customer interruptions and outages, improved accuracy with estimated restoration times and faster outage restoration; all of which add up to increased system hardening, resiliency and overall improved customer experience. Mr. Rawlinson testified that a more resilient system maintains service to customers even when some system components fail. He said CEI South understands the importance and related savings, not only to the system but also for customers, of replacing aging, poorly performing assets before they fail. He said the proactive replacement of assets before failure enables the Company to plan the work rather than be reactive in an emergency. Mr. Rawlinson explained that planned work creates fewer customer disruptions and reduces after-hours work and emergency work. Pet. Ex. 2 at 31.

With respect to hardening and resiliency, Mr. Rawlinson testified that CEI South recognizes hardening as the ability for the electric system to physically withstand damages from severe weather or extreme events. He explained that while resiliency is one of the outputs from a hardened system, resiliency is also impacted by the modernization of the system assets, because a modernized system is a smarter system and allows the grid to react faster and more effectively to severe events. Pet. Ex. 2 at 9. While a more hardened system helps prevent damage, Mr. Rawlinson testified that a resilient system facilitates quicker recovery when those damages or outages do occur. *Id.* He stated a direct benefit of replacing aging assets that have surpassed or are nearing their end of life is avoiding outages caused by those assets failing. *Id.* Mr. Rawlinson described the Company's engineering and construction standards have evolved over time since those initial assets were put into service. He said the newer standards provide a more hardened system leading to better resiliency through severe events such as weather. *Id.* Mr. Rawlinson testified that all seven of the Programs in the TDSIC Plan support resiliency and hardening of CEI South's electric system and overall grid. *Id.* He noted that modernization projects, such as distribution automation, supervisory control and data acquisition ("SCADA") upgrades, microprocessor relay upgrades and optical ground wire installation increase flexibility and functionality of the overall electric system. *Id.* at 10.

With respect to the reliability and modernization aspects of the TDSIC Plan, Mr. Rawlinson testified that the 2024 – 2028 TDSIC Plan is designed to maintain and enhance CEI South's grid reliability and resiliency, manage life-cycle investments from aging equipment, and modernize CEI South's grid for long-term customer benefit while continuing to deliver service safely. He explained that replacing aging infrastructure and implementing new or upgraded technology that was not previously available allows the Company to better serve its customers in a safer way for them, the public, and those that work on the electric system. In particular, replacement of aging infrastructure to address the causes of outages, equipment failures, brief interruptions, and enhance controls around distribution and transmission lines and substation equipment benefits customers in the long-term by increasing overall safety and reliability. Mr. Rawlinson stated that, where applicable, CEI South also incorporated looping into projects that will improve grid resilience by providing alternate feeds for reenergizing customers during extended outages. By investing in the assets to ensure proper life-cycle management, Mr. Rawlinson stated the system should provide reduced future reactive/restorative costs to customers from aging equipment failures. He explained that by proactively replacing those assets, the Company will maintain and improve reliability by lowering the number of outages that customers experience during blue sky days, extreme weather events, and unexpected system changes. The projects that have been identified to replace aging assets are designed based on updated engineering and material standards that help meet the needs for today and the needs of the future grid. Mr. Rawlinson testified that grid flexibility and optionality are key aspects of the Company's overall modernization strategy. A modernized grid will position CEI South to better meet its customers' future energy needs by ensuring electric reliability and providing a flexible, resilient, secure, sustainable and adaptable platform for DER integration and other consumer benefits. Pet. Ex. 2 at 10-11.

Mr. Rawlinson testified that the Company's TDSIC Plan will increase and continue to advance the electric grid design to support renewable investments by the state and by customers. He said CEI South's Distribution Automation ("DA") Program that was started in the 44910 TDSIC Plan is a great example of this system support. He explained the DA scheme builds out the ability to have a communication restoration scheme which in turn can assist DER applications to come back online quicker. CEI South's 2024 – 2028 TDSIC Plan will carry on that modernization and increase the system communication and intelligence. Programs in the TDSIC Plan such as Substation Rebuilds, DA, and some Distribution 12kV Rebuilds and Transmission Rebuilds directly support this effort. Distributed Energy Resources could potentially push electricity onto the transmission system although the system was originally designed for one-way power flow to the customer. Per FERC Order 2222, utilities will need a host of monitoring and control systems to support the grid as DER/EV penetration evolves over time. Mr. Rawlinson explained that a two-way smart grid is better adapted to accommodate the evolution of the power system. Circuit tie advancements and added visibility through DA and distribution upgrades support a two-way smarter electric grid system. Pet. Ex. 2 at 13.

With respect to the Substation Physical Security projects, Mr. Freeman testified that the purpose of the security projects described in his testimony is to add additional security control measures at the Company's substations to prevent a physical attack on those assets. Due to the inherent risk of severe injury or death due to a trespasser entering a substation, these added controls increase public safety. Further, these added controls will help protect system reliability. Previous attacks on electric substations have led to mass outages lasting for a number of days. Mr. Freeman testified that these outages put the health, safety, and welfare of the Company's customers and the public at-large at risk and can cause millions of dollars in property damage. Moreover, due to the possibility of damage to system components, these added controls increase reliability and increase safety of CEI South employees and contractors working on site. Pet. Ex. 5 at 7.

Petitioner's Witness Thibodeau presented the economic impact analysis performed by Sargent & Lundy ("S&L") to calculate the projected economic benefits of the estimated capital expenditures associated with the projects included in the TDSIC Plan, including net employment, labor income, value added to the market, wages injected into the economy (output), and federal, state, and local taxes. Pet. Ex. 4, Attachment MRT-1. He explained that S&L reviewed and evaluated the economic impact of CEI South's projected construction and development expenditures associated with CEI South's 2024 – 2028 TDSIC Plan. S&L's study was limited to capital expenditures relating to transmission and distribution systems and did not include the economic impact of operation and maintenance ("O&M") expense. S&L's Economic Impact Report estimates the direct, indirect, and induced impacts of these expenditures on two different geographic regions—Indiana and the remaining United States. Each impact is broken down into the following types: supported employment, labor income, value added (Gross Domestic Product), and total economic output. From these impact types, estimates of wages, federal taxes, and state and local taxes were then calculated. Pet. Ex. 4 at 3-4. S&L used a combination of analytical processing in Microsoft Excel 2021 to organize the expenditures into an economic framework as well as the impact analysis for planning (IMPLAN) version 7.2 software for modeling the economic impact of the expenditures. *Id.* at 4. The cost input used in the analysis is entirely based on the direct project costs that are proposed by CEI South. The results of the analysis quantify the estimated employment, labor income, GDP (value added), economic output, and tax income resulting from the proposed projects. *Id.* at 6-7.

Petitioner's Witness De Stigter also describes additional customer benefits identified in the Risk Model as the avoided costs to customers by the replacement of assets prior to failure. As further explained in detail in Mr. De Stigter's testimony, the Department of Energy has an Interruption Cost Estimate ("ICE") calculator which was used to produce this analysis. Pet. Ex. 2 at 32.

iv. Cost Estimates.

Mr. Leger explained that CEI South engaged with both internal and external subject matter experts ("SMEs") to arrive at the cost estimates and that, with the exception of the Wood Pole Replacement Program and the five Substation Physical Security Surveillance System Projects, each Project within the complete TDSIC Plan was estimated to follow the recommended practices of AACE International ("AACE"), with Projects planned to be completed in the first two years of the TDSIC Plan designed to AACE Class 2 criteria and the remaining projects designed to AACE Class 4 estimate criteria. Pet. Ex. 1 at 9.

Mr. Rawlinson presented the estimated cost of the TDSIC Plan. He said CEI South has created a detailed cost estimate for each Project, including PSPs, for all Programs within the TDSIC Plan except the Wood Pole Replacement Program and the five Projects in the Substation Physical Security Program. The Wood Pole Replacement Program and Substation Physical Security Surveillance System Projects do not represent a specific location and therefore have an estimated cost at the Program level by planned year but do not have unique projects identified with an associated estimated cost for this filing. For all other projects, each detailed cost estimate includes a line-item breakdown of the cost including engineering, contract labor, material, construction and material loadings, land, easements, and survey work as applicable. As explained below, escalation and contingency are included in the total best estimate. A comprehensive list of the best estimates of the TDSIC Plan can be found in Petitioner's Exhibit No. 2, Attachment SRR-1 (CONFIDENTIAL). *See* Pet. Ex. 2 at 28-29.

Mr. Rawlinson testified that CEI South's methodology for developing estimates was a thorough process which included both internal and external SMEs. The Company started with the project identification and selection process described above. Over 5,000 prospective projects were identified as an outcome of that process and CEI South intends to complete 319 projects within the five-year Plan. An additional 114 projects were identified as PSPs. As noted earlier, Mr. Rawlinson explained that all 423 of the projects, outside of the Wood Pole Replacement Program and a portion of the Substation Physical Security Upgrades, have detailed cost estimates. He explained that the Wood Pole Replacement Program and Substation Physical Security Surveillance System Projects have an estimated cost at the Program level by planned year, but do not have unique projects identified with an associated estimated cost in Petitioner's filing. Pet. Ex. 2 at 22.

Mr. Rawlinson described the process of estimating the costs as follows: Initially CEI South reviewed each Project's associated scope of work and leveraged historical cost information to create a high-level preliminary estimate. The Company then grouped these Projects into tentative planned years by Program using the preliminary estimates along with an expected annual Plan budget. As a result, a draft five-year Plan by year was created. Then, each Project within the complete TDSIC Plan was estimated to follow the recommended practices of AACE, formerly Association for the Advancement of Cost Engineering International. Pet. Ex. 2 at 22. He explained that AACE specifies five estimate classes, with Class 1 estimates representing those projects that have the greatest level of detail and an accuracy range of -10% to 15% and Class 5 having the least amount of detail with an expected accuracy range of -50% to 100%. *Id.* With the exception of the Wood Pole Replacement Program and the five Substation Physical Security Surveillance System Projects, all Projects, including PSPs, have a unique estimated cost at the AACE Class 2 or Class 4 accuracy level. Projects planned to be completed in the first two years of the TDSIC Plan were designed to AACE Class 2 criteria and the remaining projects, including PSPs, have been designed to AACE Class 4 estimate criteria. *Id.* at 23, 25, 28. Mr. Rawlinson testified that Class 2 estimates, which have accuracy ranges of -15% to +20%, balance the level of detail and confidence in design with appropriate engineering resource utilization to ensure accurate estimates and work plans are developed for projects to be executed in the next two years. He said Class 4 estimates have an accuracy range of -30% to +50% and are appropriate for projects completed beyond the first two-years by balancing a reasonable level of work scope detail and estimate accuracy while effectively utilizing engineering resources. *Id.* at 23.

Mr. Rawlinson went on to explain that designing all projects to a Class 2 accuracy level is not an effective or efficient use of resources due to potential changes in work scope and fluctuating material and labor costs that occur as time passes. He stated the Class 4 estimates will be refined about a year in advance of execution and then updated in the TDSIC Plan. *Id.* at 24.

With these criteria established, the estimates were developed with a combination of internal and external engineering resources using CEI South's engineering systems and standards. *Id.* at 24. For direct costs, CEI South worked with 1898 and CHA Consulting to utilize previously completed projects of similar size and scope, quotes from material vendors and SME knowledge of constructing projects in southwest Indiana to determine the direct capital costs for project estimation. With respect to indirect costs, Mr. Rawlinson stated the Company reviewed historical indirect capital costs in addition to long-term forecasted capital investments to derive a projected indirect percentage. That percentage was utilized in each project cost estimate. Mr. Rawlinson testified that CEI South used 12% for indirect capital costs in the Plan. *Id.* at 25-26.

Mr. Rawlinson stated escalation associated with inflation of materials, labor, and services is calculated on each project's summary work paper, which shows total project cost. He said CEI South worked with 1898, who utilized various economic, and inflation forecast information, to determine the short-term escalation at 4% per year starting in 2024 through 2028. *Id.* at 26.

With respect to contingency, he explained the contingency applied to projects was based on the amount of detail and confidence in the scope of work and design to ensure accurate estimates were developed for projects. CEI South used 12.5% contingency on projects in years 2024 – 2025 and 17.5% contingency on projects for years 2026 – 2028 and PSPs. *Id.* at 26. The percentage of contingency added to each project's summary work paper was determined by the comprehensiveness of the scope of work, level of engineering, complexity of the project, and site condition detail. Mr. Rawlinson explained the same percentage of contingency was not applied to all projects. AACE states that adding contingency increases the probability of underrunning the final estimate value and decreases the probability of overrunning the final estimate value. Contingencies are an applicable element of project estimates. He testified that the use of contingencies is standard practice throughout the utility industry to capture costs for unknowns which often occur and is required for the Company to create the best estimate of costs of eligible improvements. In order for CEI South to submit a best estimate of the cost, contingency has to be included. Submitting a best estimate is required by the TDSIC Statute. The Company knows there are always unknowns and risk is inherent with all projects and contingency is added to cover that unidentified variable. The contingency added to an estimate is included for items, conditions, or events for which the occurrence or effect is uncertain and that historically results in additional costs. *Id.* at 27.

v. Incremental Benefits Analysis.

Mr. Leger testified that CEI South engaged in a robust analysis of the incremental benefits of the TDSIC Plan as compared to the estimated costs and that the TDSIC Plan's incremental benefits justify its cost, while reducing risk associated with the electric grid and increasing overall reliability and safety of the system. Pet. Ex. 1 at 9. Mr. Rawlinson testified that each project and program completed in CEI South's TDSIC Plan will bring customers some combination of the following incremental benefits: enhanced system reliability, resilience, deliverability, safety and modernization. Pet. Ex. 2 at 31.

Mr. De Stigter testified that the Plan has a quantified benefit in excess of cost for a benefit cost ratio of 1.7. Additionally, for the 5 programs that included a quantitative business case, he showed that benefits are in excess of cost for each program. Further, for each individual investment for which a quantitative benefit was measured, the quantified incremental benefit exceeds the cost. Mr. De Stigter showed that many of the investments have additional qualitative benefits. Pet. Ex. 3 at 5-6 and Attachment JDD-2.

Mr. De Stigter testified that approximately 81.2 percent of the Plan investment was identified utilizing the Risk & Resiliency analytics approach. His testimony (at Figure JDD-11) showed the quantified business case results for each project (including nearly 270 individual investments), ranked from highest BCR to lowest. He said each risk & resiliency identified project has a quantified business case with benefits in excess of cost, BCR greater than 1. For all risk & resiliency analytics defined projects, Mr. De Stigter showed the total investment of $325.8 million (2023 dollars) produces life cycle PV of benefits of $681.3 million. In aggregate, all risk & resiliency analytics defined projects have a positive quantified business case with a total NPV of $355.5 million for customers and a benefit cost ratio of 2.1 Pet Ex. 3 at 30.

According to Mr. Rawlinson and Mr. De Stigter, there were Programs and Projects for which 1898 was unable to monetize the incremental benefits. The Wood Pole Replacement Program, Substation Physical Security Program, and a few select other Projects in the other Programs were not assessed through the Risk Model. Pet. Ex. 2 at 15. For the qualitative evaluated investments identified by CEI South System Stakeholders, Mr. De Stigter testified that the main benefit drivers are safety and delivering service, which both align to CEI South Plan Objectives and TDSIC Purposes. Pet. Ex. 3 at 5-6 and Attachment JDD-2. Mr. De Stigter explained the business case framework for these investments is based on their alignment to the CEI South Plan

Objectives, and by extension the TDSIC Purposes given the two are tightly aligned. He said approximately 18.8 percent, $85 million, of the Plan was identified by CEI South System Stakeholders (planning, engineering, field operations, and maintenance). Pet. Ex. 3 at 33.

Mr. De Stigter said the largest program from these identified investments is the Wood Pole Replacement Program with over half of the $85.3 million investment. He explained that this program improves safety, reliability and resiliency, and manages long-term costs by replacing poles with known defects based on inspections. Poles with known defects are at elevated risk of failing. *Id.* at 33-34. Mr. Rawlinson stated the Wood Pole Replacement Program will be inspection driven for the identification of assets that will be replaced. This Program involves inspecting 10 percent of wood poles across the CEI South system annually as part of a 10-year cycle, which is the industry standard. The Company will be inspecting the poles prior to identification for replacement. As part of the process, poles that have structural issues will be identified and those that can be restored will be treated, both internally and externally, to extend pole life. Those poles replaced or treated will meet the National Electric Safety Code ("NESC") requirements and CEI South's engineering design and material standards. Pet. Ex. 2 at 15.

Mr. De Stigter stated the Substation Physical Security is the second largest investment program, approximately 16.4 percent of the total, identified by CEI South System Stakeholders. He testified that intentional vandalism toward substations equipment has seen an increase recently, and these events can cause significant disruption to serving customers and can be costly to restore. The investments in this program will provide additional monitoring, specifically cameras, to help mitigate these events. Pet. Ex. 3 at 34.

He said the remaining investment of $26.3 million for transmission line rebuild, substation rebuild, and distribution 12kV circuit rebuild are mainly to mitigate against system capacity constraints and improve power quality. This accounts for approximately 30.8 percent of the investment identified by CEI South System Stakeholders. In terms of the total Plan, Mr. De Stigter testified that these projects account for approximately 5.8 percent of the total Plan investment. He explained that if capacity constraints are not mitigated, there is risk of overloading equipment causing it to burn or not being able to utilize switching schemes to minimize disruptions to customers. *Id*.

Mr. Rawlinson also discussed the qualitative benefits of the Substation Physical Security projects as well as the projects identified as deliverability, stating these projects are installation of new assets and not necessarily replacement of existing assets. He said these projects are needed to protect the transmission and distribution system from the threat of terrorist attack. The harm from interruptions and disruptions from intentional acts of violence are immeasurable, and so attempting to monetize incremental benefits would be pointless. Pet. Ex. 2 at 15. He explained that distribution substation expansion projects consist of the installation of power transformers and high voltage equipment to support required new distribution circuits for economic growth and switching capacity. Increasing capacity across the system supports planned switching and future Distribution Automation device installations to use during an outage event. He said distribution capacitor bank projects are being proposed to either rebuild or install new banks to improve the power factor on the selected 12kV circuits. Mr. Rawlinson testified that circuits with low or lagging power factor are inefficient and cause the utility to generate excess power to offset circuit losses. Improving the power factor on the distribution system will have a cumulative effect of improving the power factor on the transmission system, which reduces the overall power generation demand. For these reasons, Mr. Rawlinson said these projects do not lend themselves to be run through the risk model. Pet. Ex. 2 at 15-16.

Mr. De Stigter also showed the business case results for the PSP investments. He showed the total potential investment of $188.2 million produces life cycle PV of benefits of $359.1 ($190.0 + 169.1) million for a benefit cost ratio of 1.9. From an aggregate perspective, this investment category has a positive business case. The reactive cost benefits alone cover approximately 53 percent of the total investment. Pet. Ex. 3 at 35-36.

vi. Plan Updates.

Mr. Rawlinson testified that the TDSIC Plan will require periodic updating. He stated as Class 4 estimates change to Class 2 estimates, there may be increased or decreased project costs that require new cost estimates to be filed. He identified factors that may drive these changes, including the impact of market forces on major equipment suppliers and their costs, unforeseen changes in site conditions, and movement of planned construction years due to changing system or operational needs or availability of materials. Pet. Ex. 2 at 34. He explained that portfolio management to maximize efficiencies of the annual capital investments is achieved through these periodic updates. *Id*. CEI South proposes to update for actual costs every six months through the semi-annual tracker filings. In the semi-annual filings, CEI South proposes to include the actual completed costs of the projects for the current filing period and any variance commentary as required. *Id.* CEI South also proposes to update the TDSIC Plan at least once a year through a semi-annual filing. Mr. Rawlinson explained that means that, at a minimum, once per year, CEI South will include potential changes to the Plan that include new best estimate of costs as well as information related to projects that are moving between plan years, or projects that are moving in or out of the Plan. He stated the Company proposes to adjust project estimates once per year in one of the semi-annual filings. *Id.* at 35.

vii. Accounting Treatment.

Ms. Behme described the accounting treatment CEI South is requesting in this case. She stated CEI South is requesting: (1) Recovery of 80% of approved capital expenditures and TDSIC costs via a rate adjustment mechanism, including costs associated with (a) Capital investment in eligible projects, both completed and under construction, (b) Financing costs on projects under construction (i.e., allowance for funds used during construction or "AFUDC"), (c) Post-in-service carrying costs ("PISCC"), (d) Projected and annualized property tax and depreciation expense, (e) Amortization of deferred depreciation expense, planning development expense, and PISCC; (2) Deferral of 20% of approved capital expenditures and TDSIC costs, for subsequent recovery in a base rate case, including costs associated with (a) Capital investment in eligible projects, both completed and under construction, (b) Financing costs on projects under construction (i.e., AFUDC), (c) PISCC, (d) Projected and annualized property tax and depreciation expense, (e) Amortization of deferred depreciation expense, planning development expense, and PISCC; and (3) Interim depreciation and PISCC deferrals and subsequent recovery of deferred amounts via the rate adjustment mechanism. Pet. Ex. 6 at 4-5.

Ms. Behme explained that for purposes of the revenue requirement for CEI South's Semi-Annual TDSIC filings, new capital investment includes gross plant, both in service and Construction Work in Progress ("CWIP"), specific to investments under the TDSIC Plan as well as amounts associated with prepayments made in 2022 and 2023 for essential equipment ordered in advance. She testified that the prepayments were necessary in order to receive equipment by the 2024 – 2028 TDSIC Plan start date. Ms. Behme explained that the accumulated depreciation on these new capital investments, net of any cost of removal or salvage related to the disposal of assets retired and replaced because of these investments, will be included as a reduction to the gross plant balance. Ms. Behme also stated the PISCC on in-service investments not yet captured for recovery in the TDSIC will be added to the net new capital investments. She said CEI South will utilize the actual balance as of the filing cut-off date to calculate the annualized depreciation expense and PISCC not yet captured for recovery in the TDSIC. Pet. Ex. 6 at 5.

According to Ms. Behme, CEI South proposes that the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the weighted average cost of capital ("WACC"), by the total new capital investment related to the proposed TDSIC Plan. The same rate would be used to calculate pre-tax return on CWIP. *Id.* at 5 and Attachment CMB-1, Sch. 1, line 4 and Sch. 4, line 17. CEI South proposes to use a WACC for the TDSIC based upon the actual capital structure at the end of each respective measurement period in the TDSIC, inclusive of the typical items included in the Company's base rate case capital structure: (1) long-term debt, (2) common equity, (3) customer deposits, (4) cost-free capital, including deferred income taxes, and (5) investment tax credits. Ms. Behme testified that, consistent with the TDSIC Statute, the balances and cost of debt will be based on the actual amounts, and the cost of equity will be set at 10.4% as approved in the Company's most recent rate case order. This rate will be used in the TDSIC revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. Pet. Ex. 6 at 6.

Ms. Behme also explained that CEI South proposes that, as provided for in the TDSIC Statute, the remaining 20% of eligible revenue requirement amount shall be deferred in a regulatory asset for recovery as part of CEI South's next two base rate case proceedings with the Commission as further described by Mr. Rice. Consistent with the 80% portion recoverable in the TDSIC, the revenue requirement calculation will be used to derive the 20% deferred for future recovery. Pet. Ex. 6 at 6. Mr. Rice testified that the 20% that is deferred is to be recovered as a part of the "next general rate case." CEI South is required to, and will, file its "next general rate case" before December 31, 2023. The Company has proposed that the portion that has been deferred pursuant to the 2024 – 2028 TDSIC Plan by the cutoff in the rate case to be filed later this year would be recovered in the upcoming rate case. Pet. Ex. 7 at 4-5. Mr. Rice stated the remainder that is deferred over the remainder of the 2024 – 2028 TDSIC Plan would be recovered as a part of the general rate case after the one to be filed later this year. *Id.* at 5.

Ms. Behme testified that CEI South proposes to defer depreciation expense on the capital investments in the TDSIC Plan, from their in-service dates until the date TDSIC rates are effective. She stated commencing on the date the projects are placed in service, the depreciation expense will be charged to FERC Account 403, Depreciation Expense, with a corresponding credit to FERC Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. Pet. Ex. 6

at 6. Concurrently, Ms. Behme said the deferral of depreciation would be recorded as a charge to FERC Account 182.3, Other Regulatory Assets, and a credit for FERC Account 407.4, Regulatory Credits, until such point as the assets will be included in the TDSIC and recovered through rates. Ms. Behme testified that the proposed accounting for the deferral of depreciation is in accordance with GAAP and, specifically, Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 980. ASC 980 specifies that an entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes and the future revenue will be provided to permit recovery of the previously incurred cost. *Id.* at 7.

Ms. Behme explained that CEI South will amortize the cumulative deferred balances over time and include the amortization amount in the TDSIC revenue requirements. Specific to depreciation expense, CEI South proposes to amortize the deferred balance through the TDSIC over the life of the assets that generated the depreciation expense. Ms. Behme said the calculation will utilize the depreciation rates applicable to the class of plant as the basis for the amortization period, as approved in the most recent CEI South general rate case. *Id.*

Ms. Behme also explained that CEI South has incurred costs to assist in the development of the TDSIC Plan, including engineering and development of detailed cost estimates, incremental benefit analysis, and support during case development. She testified that these costs are directly linked with the TDSIC Plan proposed in this filing. CEI South proposes to defer these costs in FERC Account 182.3 for subsequent recovery in the proposed TDSIC. CEI South proposes to amortize and recover this deferred balance through the TDSIC over a period of five (5) years. *Id.* She said this is similar to how such costs were treated in the 44910 TDSIC Plan, although in the 44910 TDSIC Plan the costs were amortized over a shorter period of time. *Id.*

Ms. Behme testified that CEI South is seeking authority to recover through the TDSIC annualized depreciation, amortization, and property tax expenses. She said in order to provide for timely recovery, CEI South's proposed TDSIC mechanism will project an annualized level of expense related to the depreciation, amortization and property tax expenses associated with new capital investments. Depreciation expense included for recovery will reflect an annualized level of expense related to the gross new capital investment as of the cut-off date of the TDSIC filing. Property tax expense will also reflect an annualized level. Consistent with the current TDSIC, the annualized level will be calculated by multiplying the gross new capital investment by the then current or most recent tax rate for the projected period. Because the projected amount is calculated consistent with the actual property tax expense and because the property tax rates do not materially vary year over year, she testified that there will be no reconciliation of property tax expense. *Id.* at 8.

CEI South proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during the construction of eligible investments under the TDSIC Plan. Under CWIP ratemaking treatment, Ms. Behme explained that CEI South will recover, through the TDSIC, financing costs incurred during the construction period attributable to eligible capital investments. Pet. Ex. 6 at 8. She stated CWIP ratemaking treatment allows a utility to recover its costs in a timely manner and avoid the impacts of regulatory lag by recovering financing costs as the capital costs are being incurred. *Id*. In connection with CWIP ratemaking treatment, Ms. Behme stated CEI South will cease accruing AFUDC the earlier of the date in which the project expenditures receive CWIP ratemaking treatment through the TDSIC or the month after the investment is used and useful and the project is placed into service. *Id.* at 9.

Ms. Behme described CEI South's proposal to accrue PISCC on all eligible new capital investment from the date the investment is placed in service until the date when the investment is included in rates for recovery. *Id.* She stated the PISCC balance will be calculated as the gross new capital investment multiplied by the pre-tax rate of return at the overall WACC. *Id.* She explained that CEI South proposes to amortize the deferred PISCC regulatory asset balance through the TDSIC over the life of the assets that generated the deferred PISCC, using the depreciation rates applicable to the applicable class of plant asset. *Id.* at 10. Ms. Behme stated CEI South is not seeking the authority to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance previously discussed. *Id.*

Ms. Behme also described in detail the process that will be used to segregate and record the new capital investments under the TDSIC Plan while they are under construction. Pet. Ex. 6 at 10-11. She confirmed that the requirements of the FERC USOA will be followed in recording of the project construction costs. Actual retirements will be reflected in the filings, impacting the gross plant balance used to determine the recoverable depreciation expense. Other than the incremental cost of removal and salvage (discussed above), the retirement of property being replaced will have no change to the overall rate base. *Id.* at 11-12.

viii. TDSIC Revenue Requirement and Recovery.

Ms. Behme testified that in each semi-annual TDSIC filing CEI South will calculate a revenue requirement for the TDSIC mechanism, using a set of schedules from the 44910 TDSIC. Exemplars of these schedules are set forth in Attachment CMB-1. She stated the revenue requirement for the TDSIC, shown on Schedule 1, will include the return on new capital investments, property tax and depreciation expenses, both projected and amortized, as well as recovery of the regulatory assets recorded through the interim deferral of depreciation expense, plan development expense, and PISCC through amortization of the regulatory assets. Pet. Ex. 6 at 13. Ms. Behme explained the revenue requirement will be divided between Transmission and Distribution investments, consistent with FERC USOA guidelines, in order to align with the Company's TDSIC allocation proposal discussed by Mr. Rice. *Id.* She said CEI South will then multiply the Transmission and Distribution annual revenue requirement by 80% to achieve the recoverable portion of the revenue requirement. *Id.* Per the TDSIC Statute, 80% of approved costs is to be recovered through a periodic rate adjustment mechanism. Accordingly, the recoverable amounts for Transmission and Distribution investments will be utilized to derive semi-annual TDSIC rates and charges based on annualized billing determinants. *Id.*

While CEI South is not proposing a TDSIC revenue requirement amount for recovery in this proceeding, Ms. Behme did present illustrative schedules demonstrating how that amount would be calculated. Pet. Ex. 6 at 13-17 and Attachment CMB-1. She explained that excess accumulated deferred income tax ("EADIT") credits are initially included within this TDSIC. Pet. Ex. 6 at 17. She stated TDSIC rates and charges include EADIT credits. *Id.* With respect to EADIT, Mr. Rice explained that Ordering paragraph 29 in the 45722 Order required CEI South to make a compliance filing on or before February 3, 2023, in that Cause with an updated tariff for the 44910 TDSIC tracker reflecting the shorter amortization period for excess ADIT related to the retirement and securitization of CEI South's A.B. Brown generation Units 1 and 2. He explained that the EADIT related to A.B. Brown Units 1 and 2 was protected under IRS normalization rules but became unprotected after the securitization bonds were issued. As a result, the 45722 Order required CEI South to update its TDSIC tariff to reflect a shorter amortization period for the A.B. Brown Units 1 and 2 EADIT ending with the scheduled maturity date of the securitization bonds. Pet. Ex. 7 at 14. Attachment MAR-3 shows a sample post-securitization A.B. Brown Units 1 and 2 EADIT amortization schedule that assumes securitization bonds are issued on June 30, 2023, and have a final maturity date in 2041 (18 years). Attachment MAR-3 also includes a comparison to the current amortization of the A.B. Brown Units 1 and 2 EADIT.

Since CEI South must file a general rate case before January 1, 2024, the Company may propose a different mechanism for EADIT credits. Pet. Ex. 6 at 17.

Ms. Behme also explained that the exemplar schedules are consistent with Petitioner's TDSIC Plan approved in Cause No. 44910 in defining the prioritization of recovery to ensure the Company receives the return on its investments granted by the TDSIC statute in accordance with ASC 980. Under this prioritization, the first dollar collected will represent the full return and the remaining amount collected will cover a portion of the incremental expense. This prioritization does not impact the amounts to be recovered in rates, as the amount recovered through the TDSIC will still be 80% of the total revenue requirement and the amount deferred will still be 20%. *Id.* at 14.

Ms. Behme testified that CEI South does not expect that the TDSIC Plan would produce a TDSIC in any year of the Plan that would result in an average aggregate increase in CEI South's total retail revenues of more than 2% in a twelve-month period. Pet. Ex. 6 at 17 and Attachment CMB-2.

Mr. Rice testified that CEI South plans to maintain the existing TDSIC filing schedule currently in place with its 44910 TDSIC Plan. He said there are two periods: May through October and November through April. The approved recoveries for the TDSIC reconciliation period will represent the TDSIC approved amounts for either May through October or November through April and will be noted in Attachment MAR-1, Schedule 4. Pet. Ex. 7 at 7. Mr. Rice described how variances would be calculated for the TDSIC Reconciliation Period and included in the TDSIC. The resulting variance is an over- or under-recovery and will be credited to customers in the TDSIC rates and charges over a six-month period. *Id.* The Company proposes to include the over- or under-recovery variances resulting from TDSIC rates in place from the 44910 TDSIC-13 and 44910 TDSIC-14 periods in the first semi-annual filing in this Cause. *Id.* Mr. Rice explained that the Company considered filing a TDSIC-15 under Cause No. 44910 to reconcile the over- or under-recovery variances resulting from 44910 TDSIC-13, and file a TDSIC-16 under Cause No. 44910 to reconcile variances resulting from 44910 TDSIC-14, but decided it was more administratively efficient to include the variances in the first semi-annual tracker filing under this Cause. *Id.* at 8. He stated the specific identification of the variance by Rate Schedule ensures that customers are paying only for the costs allocated and approved for recovery from that Rate Schedule. *Id.*

ix. TDSIC Rate Allocation.

Mr. Rice explained that CEI South is proposing to use the allocation percentages agreed to by the parties in the Cause No. 44910 Settlement until such a time as the percentages are updated in a future rate case. Pet. Ex. 7 at 8. He said allocators would be adjusted in CEI South's next general rate case. Mr. Rice explained that while the Petitioner's last base rate case was in Cause No. 43839 (Order issued in April 2011), Petitioner proposes to continue to allocate the revenue requirements for TDSIC charges based on the 44910 Settlement allocation percentages until such time as new allocators are in place in the next general rate case, which will be filed in December 2023. He said the settlement allocations account for the move of a large customer from the HLF rate class to the LP rate class and are more representative of cost causation than allocations that were put into place 12 years ago. Currently, the one remaining HLF customer pays for 0.7% of the total transmission component of the revenue requirement, as opposed to 9.1% from the 43839 Order. Mr. Rice stated the separation of the revenue requirement into transmission and distribution, as well as the exclusion of some rate groups from the distribution portion of the revenue requirement is consistent with that Settlement allocation. *Id.*

Attachment MAR-1, Schedule 2 shows the allocation of the TDSIC revenue requirement components, supported by Ms. Behme, and the derivation of TDSIC rates and charges by Rate Schedule for each component (transmission and distribution). The schedule is divided into three sections to reflect the different allocation percentages applicable to TDSIC costs to derive the proposed TDSIC charges by Rate Schedule. Pet. Ex. 7 at 9.

Attachment MAR-1, Schedule 3 presents the illustrative proposed TDSIC rates and charges by Rate Schedule using information from Schedule 2. Following the first 2024 – 2028 TDSIC Plan recovery filing, Mr. Rice explained that Schedule 3 will include current TDSIC rates and charges by Rate Schedule. He said these rates and charges will be used to calculate a percentage change in the proposed rate, by Rate Schedule. *Id.*

x. Tariff.

Mr. Rice sponsored, for illustrative purposes, Attachment MAR-2 which sets forth the proposed CEI South Tariff Sheet, Sheet No. 75 – Appendix K, containing the TDSIC rates and charges.

xi. Bill Impacts.

Mr. Rice presented the projected impact on retail rates and charges of the proposed TDSIC Plan. Attachment MAR-4 summarizes the estimated year-over-year impact that the costs associated with the 2024 – 2028 TDSIC Plan will have on customer rates, by rate schedule, over the life of the TDSIC Plan. In order to align the customer impacts to the TDSIC Plan investments, Mr. Rice stated these impacts exclude the EADIT Credits to be reflected in future TDSIC rates and charges. Pet. Ex. 7 at 15.

B. **OUCC's Case-in-Chief.** OUCC witnesses Lantrip, Krieger and Leader offered testimony in response to CEI South's requested relief. In summary, they recommended the Commission do the following: (1) Deny request to defer 20% of capital expenditures and TDSIC costs as a regulatory asset and recover over Petitioner's next two rate cases; (2) Require CEI South to update its tracker filings to ensure that the rider reflects base rate case revisions to cost of service, capital structure, cost of capital, and depreciation rates;[1] (3) Allow Petitioner to record retirements of the utility plant against the accumulated depreciation, consistent with Cause No. 44910's caveat of netting of depreciation expense of retired assets against depreciation expense of the new capital investment; (4) Allow reconciliation of Cause No. 44910 TDSIC-13 and -14 filings through the rider updates filed under this cause, provided that such reconciliations are labelled clearly and distinctly; (5) Deny Petitioner's requested contingency factors and approve the OUCC's recommendation of a 10% factor; (6) Approve witness Leader's recommendations regarding inflation, wages, and security; (7) Deny TDSIC rate recovery of $85 million of project estimates lacking quantifiable benefits, per witness Krieger's recommendations discussed in more detail below; (8) Require more appropriate and more accurate project estimates per witness Krieger's recommendations discussed in more detail below, and use its discretion to limit project approvals to those that are fully supported with complete and accurate cost estimates; and (9) Require CEI South to implement a filing schedule which alternates on a semi-annual basis between rate recovery and plan updates, consistent with what the Commission has approved in Cause Nos. 45264 and 45647. *See* Pub. Ex. 1 at 23-24.

Commented [J1]: CAC defers to the OUCC's characterization of its own evidence. Furthermore, CAC's lack of exceptions to the proposed order to reflect the OUCC's arguments should not be construed as agreement with Petitioner's proposals on those items.

i. *Timing of Filing.*

OUCC witness Lantrip testified that CEI South's proposal to defer 20% of the approved capital expenditures and TDSIC costs for the TDSIC Plan, including depreciation, AFUDC, and PISCC for recovery as part of its next two general rate cases amounts to "accelerated recovery of the required deferred amount under the new Plan." Pub. Ex. 1 at 4. He contended that the statute applies only once the utility has "actually incurred capital expenditures and TDSIC costs and petitions for the approval and recovery of those costs" which he says won't be "met until after the start of the approved multi-year TDSIC plan (on or after January 1, 2024)." *Id.* at 5 (emphasis omitted). He said "next general rate case" means after the utility has incurred expenditures and TDSIC costs and after the utility has begun recovery or petitioned for recovery of the approved capex and TDSIC costs. *Id.* at 6. Because he believes Petitioner would be "inappropriately accelerating recovery," he argued that CEI South should not receive approval to recover this 20% deferral of capital expenditures and TDSIC costs in the rate case to be filed yet this year, before the start of this TDSIC Plan. *Id.* at 6.

Mr. Lantrip expressed concern about the impact of the timing of Petitioner's TDSIC Plan filing, since he says the TDSIC statute defers to the base rate case for determining rate allocation and CEI South does not consider the Cause No. 42839 (Petitioner's last base rate case) allocation factors to accurately represent the migration of its customer base. Pub. Ex. 1 at 7. He stated the staleness of current base rates and the impending new rate case after this TDSIC proceeding "further complicate an already complex and voluminous proceeding." *Id.* He suggests

[1] OUCC specified this finding should clarify that these parameters from previous rate order should not be grandfathered in for the life of the Plan.

CEI South should have waited until after its next general rate case to make its new TDSIC Plan filing. He recommended that the Commission's order in this case clarify that TDSIC Plan recovery will be updated for base rate case elements when and as such elements are approved and ordered by the Commission. *Id.* at 9.

ii. Reliability and Resilience.

Mr. Lantrip contended that CEI South's reliability metrics (SAIDI, CAIDI and SAIFI figures) have not shown consistent improvement over the life of Petitioner's first TDSIC Plan (approved in Cause No. 44910). Pub. Ex. 1 at 10. He cited significant increases to outages in 2022 over the factors for 2021.

Mr. Krieger testified that the results of Petitioner's initial TDSIC Plan do not provide conclusive evidence that overall quantifiable benefits were provided for the investment. Reliability did not consistently improve during 2018-2022. Pub. Ex. 2 at 11. He stated the latest annual report shows all three reliability indices show poorer results for 2022 than for 2018. *Id.* at 13.

iii. Affordability.

Mr. Lantrip also urged the Commission to consider CEI South's status of "having the state's highest electric rates in 13 consecutive annual surveys" and to approve only what is verified and justifiable as reasonably necessary and at a prudent cost; he stated the Commission must factor customer affordability into the accounting treatment and into timing of project requests and prioritization. Pub. Ex. 1 at 10-11. Mr. Lantrip opined that the 2% cap under Ind. Code § 8-1-39-14 is not a sufficient incentive for the utility to manage or control costs because it is an annual cap and any amount over it can be deferred with a return until the end of the plan. *Id.* at 12. He accused CEI South of being "misleading" in its testimony in Cause No. 45836 that CEI South had been surpassed in highest electric rates because the primary factor of the change was due to the effect of quarterly FAC filings which he said have been subject to increased volatility. *Id.* at 14.

iv. Accounting Treatment.

Mr. Lantrip recommended continuation of depreciation expense accounting treatment approved in Cause No. 44910, which used annualized level of expense related to gross new capital investment, netting the expense related to retired or replaced assets with depreciation expense of new capital investments. He said this treatment did not adjust for cost of removal or salvage related to disposal of assets retire or replaced because of the investments. Pub. Ex. 1 at 17. He cited the Commission's decision in Cause No. 44182 where he said exclusion of cost of removal through a rider was upheld. *Id.* at 18.

v. Ratemaking.

Mr. Lantrip recommended the Commission's Order include a definitive finding that the utility is expected to update its plan's capital structure and cost of equity after the effective date of its newest base rate case order. Pub. Ex. 1 at 20.

He did not object to using the current proceeding's Cause number to file updates in reconciliation, provided the Cause No. 44910 costs to be reconciled are specifically identified and labeled. Pub. Ex. 1 at 22.

Mr. Lantrip recommended adopting a filing schedule that is an annual update alternating on a semi-annual basis between plan updates and cost recovery updates, similar to what he says is used by Duke and AES. Pub. Ex. 1 at 22. He opined this would provide more flexibility given timing of rate case, since Petitioner cannot file a rider filing within 9 months of rate case order. Pub. Ex. 1 at 23. Under Mr. Lantrip's proposal, the Company's first filing would be cost recovery update, followed by plan update six months later. *Id.*

vi. *Cost Estimates*.

Mr. Lantrip took issue with Petitioner's proposed 12.5% contingency on most projects, with 17.5% contingency for PSPs and projects in the last three years of the plan. He argued a 10% contingency was more consistent with other utilities. Pub. Ex. 1 at 20-21.

Mr. Krieger recommended certain parts amounting to $85 million of Petitioner's TDSIC Plan be denied because they are not supported by quantifiable benefits. Pub. Ex. 2 at 2, 3. He contended the Company's estimates for years 3-5 of the Plan are not specific enough and may result in greater expenses than necessary. *Id.* He also stated that Petitioner reliability metrics have not improved despite the near completion of Petitioner's initial TDSIC plan. *Id.* Mr. Krieger testified that CEI South has a thorough understanding of rebuilds and replacement projects, the technologies involved, their locations, and how each location matters in the broader operational scope of its distribution and transmission systems. This increases the importance for Petitioner to use stronger and more reliable cost estimates. Pub. Ex. 2 at 3. He expressed concerns about the Plan's cost-effectiveness based on Petitioner's estimates, and Petitioner's recent performance on system reliability metrics. *Id.* Mr. Krieger contended that Petitioner should have used Class 1 to Class 3 estimates and that CEI South's extensive experience in the technologies and materials utilized in the projects should permit it to be able to produce better cost estimates. Pub. Ex. 2 at 5. He argued only the Substation Physical Security Projects should require a lower Class 4 estimate since they are new technologies. *Id.* at 6. He suggested that if a "gold-plated" or over-engineered solution can be implemented within the allowable excess over a Class 4 estimate inflated by contingency and escalation, a project team may elect to proceed because the added safety margins are perceived as desirable, even though those safety margins could be achieved at a lower and much more reasonable cost. *Id.* at 7.

With respect to Petitioner's allocation of indirect capital costs of 12%, Mr. Krieger testified it is an error to allocate indirect capital costs in this manner on what he called "lower accuracy estimates" because he said a percentage multiplier may unnecessarily inflate TDSIC costs because indirect capital costs are not purely variable. Pub. Ex. 2 at 7.

Mr. Leader recommended CEI South re-do its economic impact study calculations using a 3% inflation rate over the next five years, based on the year ended June 2023 consumer price index increase of 3%. Pub. Ex. 3 at 7. Mr. Leader also recommended recalculation based on median wages for Indiana and outside Indiana of $42,100 and $58,130, respectively. Pub. Ex. 3 at 8-9.

vii. Incremental Benefits.

Mr. Krieger said CEI South provided no explanation of why the Stakeholder Projects were not identified by the same data intensive process or why they don't have quantifiable benefits. *Id.* at 8-9. Mr. Lantrip conceded that safety projects are crucial to reliability and resilience. However, he maintained that the projects must be "documented and identified" and that CEI South's case-in-chief falls short of this standard by not separately identifying projects that address safety issues or identifying individual project benefits. *Id.* at 9. According to Mr. Krieger, because safety projects cannot be specifically identified among the 18.8% of projects in the Plan without quantifiable benefits, they have not been specifically justified and should be disallowed. He contended that if a project's benefits are not quantified, it must be removed from the Plan to ensure reliability, safety and affordability. *Id.* He stated this part of the Plan is unreasonable and is not in compliance with Ind. Code § 8-1-39-10(b)(3). Mr. Krieger's recommended disallowance includes the funding for the substation physical security project. While recognizing that safety and security are critical, he maintained that it is Petitioner's burden of proof to demonstrate quantifiable benefits. *Id.* at 11.

viii. Substation Physical Security Projects.

OUCC witness Leader was generally supportive of the Substation Physical Security Projects, but recommended that if approved as part of the Plan, CEI South ensure compliance with applicable laws, place signage alerting visitors to the presence of cameras, and locate cameras consistent with requirements of applicable audio and video recording laws. Pub. Ex. 3 at 5-7. He also recommended CEI South create a robust action plan if the Substation Physical Security Projects are approved as part of the Plan. *Id.* at 9.

C. CAC Testimony. CAC witness Inskeep opposed CEI South's proposed cost allocation and rate design. He also ~~took issue with~~characterized statements made by CEI South with respect to the benefits of the TDSIC Plan for distributed generation~~, characterizing them~~ as unverifiable and unsupported. CAC Ex. 1 at 5-6. He testified that CEI South's TDSIC Plan would impose a substantial additional financial burden on customers who he ~~alleged~~ testified "already pay the highest electricity bills in the state." CAC Ex. 1 at 4. He recommended the Commission deny CEI South's proposed TDSIC Plan cost recovery mechanism to recover 100% of distribution costs from residential and small commercial customers through a fixed charge. *Id.* He ~~claimed~~ illustrated how it is unusual for an electric utility to increase its fixed charges on residential customers outside of a base rate case. *Id.* At 10-11. He instead advocated that Petitioner's cost recovery from these customers should be through variable per-kWh charges. CAC Ex. 1 at 21. He stated that CEI South customers with higher or growing demand put additional strain on the distribution system, which can lead to the need for upgrades and expansions, resulting in additional capital and operating costs ultimately borne by customers. According to Mr. Inskeep, CEI South should therefore recover distribution costs on the basis of customer end-use consumption. *Id.* at 10. Mr. Inskeep testified that all costs, including distribution system costs, are actually variable in the long run. *Id.* at 11-12.

D. CEI South Rebuttal.

i. Cost Estimates.

In response to Mr. Krieger's testimony that CEI South should have used Class 1 and Class 3 estimates, Mr. Rawlinson responded in rebuttal that using Class 1 estimates as Mr. Krieger suggests is not necessary or appropriate for planning level estimates to meet the TDSIC requirements for the proposed Plan. Pet. Ex. 2-R at 5. Mr. Rawlinson explained that Petitioner used Class 2 estimates for the first two-years of the Plan and Class 4 estimates for the remaining years of the Plan (i.e., years three to five) because a Class 2 estimate, which has an accuracy range of –15% to +20%, is appropriate for projects to be executed in the next one to two years and balances the level of detail and confidence in design with appropriate engineering resource utilization to ensure accurate estimates and work plans are developed for the projects. *Id.* at 5. He explained that Class 1 estimates are current control estimates used for project execution. *Id.* He stated Class 1 estimates for projects that are not yet ready for final execution would likely result in wasted time and resources, as a new estimate may need to be prepared at the time of actual execution for any changes in scope or design. The same is true of Class 3 versus Class 4 estimates; preparing a detailed, Class 3 estimate for a project that will not be executed until later in the Plan would likely result in wasted resources. *Id.* He testified that Class 2 and Class 4 estimates balance a reasonable level of work scope detail, estimate accuracy, and engineering resources consistent with the requirements of the TDSIC Statute, *i.e*., the "best estimate." *Id.*

Mr. Rawlinson testified that CEI South has leveraged its experience of designing and estimating similar projects to incorporate lessons learned by conducting either on-site visits, aerial photography, and/or geospatial data reviews with engineering and operations teams to assess locational factors of each project. In Mr. Rawlinson's opinion, accounting for these site-specific factors combined with CEI South's experience and knowledge increased the strength of each estimate, reducing risk. He testified that the Class 2 and Class 4 estimates within CEI South's Plan are substantial and well-defined; were prepared using CEI South equipment and design standards; have an appropriate level of engineering and scope definition and excluding the Wood Pole Replacement Program, include site specific factors to improve the accuracy of the estimate; and meet the Class 2 and Class 4 estimating criteria. Pet. Ex. 2-R at 6.

Mr. Rawlinson rejected Mr. Krieger's suggestion that Class 4 estimates create a risk of over-spending. Pet. Ex. 2-R at 6. He stated the Class 4 and Class 2 estimates included in the Plan have an appropriate level of engineering and scope definition, including site specific factors to strengthen the accuracy of the estimates; are accurate and complete; and meet AACE Class 2 and Class 4 estimating guidelines. Furthermore, because the accuracy ranges overlap for the AACE Class 2 and 4 estimate classes, CEI South adjusted the contingency values among the Class 2 and Class 4 estimates to account for the stage of the estimate along with the level of engineering and scope definition associated with that particular class. Pet. Ex. 2-R at 6. Mr. Rawlinson rejected Mr. Krieger's suggestion that a Class 4 estimate will necessarily be higher because its accuracy range is wider. He explained a project estimated as a Class 4 may be equal to the same project estimated as a Class 2. It is the scope definition and accuracy range of the class estimate that is further refined as the timeline for execution of the project nears and project matures when moving from Class 4 to Class 3 or Class 2. *Id.* at 7.

Mr. Rawlinson also pointed out that the estimates provided within the subject Cause are best estimates, which "by definition [are not] the same as actual project costs that will be recovered." Pet. Ex. 2-R at 7 (citing *Southern Ind. Gas & Elec. Co.,* Cause No. 45612 (IURC

4/20/2022), p. 16) CEI South is not seeking recovery in this filing; however, if actual costs of the investments are below the best estimate, CEI South will only seek to recover the final, actual costs of the investments in the filing for recovery. *Id.*

With respect to contingency, Mr. Rawlinson testified that including a reasonable amount of contingency is standard and accepted practice in the industry and extremely useful, especially in today's volatile market to establish a buffer to absorb reasonable, yet unidentified or unknown conditions, events, or changes that could add to the cost of the project. *Id.* at 7. He opined that a cost estimate without contingency would not be considered a "best estimate" as required by the TDSIC Statute. *Id.* at 8.

In responding to OUCC witness Lantrip's recommendation of a flat 10% contingency, Mr. Rawlinson explained that a flat 10% contingency rate for all 5 years of the plan would not account for the difference in accuracy between a Class 2 and Class 4 estimate. Mr. Lantrip's recommendation also places less reliance on the most recent of the orders he cites, which is the 15% contingency approved for Duke. The Duke contingency is in line with the contingency Mr. Rawlinson recommended. He noted the other two orders Mr. Lantrip cites are from 2020 and 2021, which is before the significant inflation, supply chain constraints, and equipment lead times seen today and being seen at the time of the Duke Order. Further, Mr. Rawlinson pointed out, the level of contingency being proposed is below the levels included in the Company's current electric TDSIC plan (Cause No. 44910) (15% for the first three years and 25% for the remaining years). Pet. Ex. 2-R at 8.

Mr. Rawlinson also testified that he considered escalation a component of a best estimate. He stated CEI South used 4% escalation to account for inflation of materials, labor, and services. Pet. Ex. 2-R at 9. He explained that escalation is a provision in estimates to account for changes in market or economic conditions over time and is both a component of cost estimating and to a lesser extent, risk mitigation. Specifically, Mr. Rawlinson explained that escalation is an accepted method of modifying an estimate in today's – or some other specified year's – dollars to reflect the expected estimate in a future year. As such, CEI South's objective in using the escalation factor was to provide more accurate estimates for work orders in later years. *Id.*

In response to the OUCC's recommendation to use a 3% inflation rate based on the Bureau of Labor Statistics inflation rate for consumer goods and services for the year ended June 2023, Mr. Rawlinson testified that the 4% inflation rate used by CEI South was based on 1898 & Co.'s utilization of various economic, and inflation forecast information, including the Handy- Whitman Index, which accounts for construction costs. Pet. Ex. 2-R at 9. Mr. De Stigter expressed his concern in rebuttal with OUCC witness Lantrip's recommendation of 3% because it is based on the average inflation of the entire United States economy. Mr. Lantrip's 3% value is a composite of many economic sectors, and it may not represent the expected inflation for an electric utility in the North Central part of the United States. Mr. De Stigter noted that a key issue, as it relates to the entire electric industry, is equipment supply chain constraints and lead times to procure equipment. The current expectation across the entire electric industry is that these supply chain constraints will not ease for the foreseeable future. He said this will put upward pressure on pricing. He also noted that labor markets are different across regions and that the overall increase in utility investment to manage aging infrastructure is also putting upward pressure on labor rates. He said these differences must be factored in when establishing the escalation rate for a capital plan. Pet. Ex. 3-R at 5.

Mr. De Stigter showed that the escalation index values from the Handy-Whitman data source (going back to 1950) shows escalation on a 5-year rolling average basis to align to CEI South's 5-year plan. Pet. Ex. 3-R at 6. He explained this data shows the most recent annual escalation for transmission and distribution is 5.39 percent and 8.48 percent, respectively, well above the 4 percent value within the Plan. *Id.* at 7. The annual average escalation over the 74-year time horizon is 4.42 percent for transmission and 4.62 percent for distribution which is above the 4 percent value within the Plan. *Id.* In addition, Mr. De Stigter's testimony presents data that shows that since the early 2000s, with the exception of 1 year, transmission and distribution escalation has exceeded the inflation of the US Economy. *Id*.

Mr. Rawlinson rebutted Mr. Krieger's suggestion that CEI South's allocation of 12% indirect capital costs on Class 4 estimates is erroneous. Pet. Ex. 2-R at 10. He explained that it is common in the utility industry that certain indirect costs related to engineering, supervision, general corporate and various administrative functions are capitalized to construction projects. In other words, these are costs associated with executing capital construction work, but they cannot be easily quantified in discrete dollar amounts for each individual project. The accepted practice, Mr. Rawlinson explained, is to allocate a percentage of these costs to each project estimate, regardless of whether the estimate is a Class 2 or Class 4. Even though a Class 4 estimate has a wider range of accuracy, that does not imply that the estimate itself is higher as Mr. Krieger suggests. Indirect capital costs are a component of the "best estimate" as required by the TDSIC Statute. *Id.*

ii. Economic Impact Report

Mr. Thibodeau responded in rebuttal to the OUCC's recommendations regarding the calculations in the economic impact analysis. He explained that S&L used the impact analysis for planning (IMPLAN) version 7.2 software for modeling the economic impact of the expenditures. CEI South provided S&L with inputs for the analysis in the form of capital cost breakdowns and vendor details for each TDSIC program. The vendors were categorized as either material vendors, labor vendors, or engineering vendors. Each TDSIC program also includes a portion of the costs allocated to CEI South's overhead. Mr. Thibodeau stated S&L takes these data as input into its analysis. The output of S&L's analysis is a reformatted allocation of the costs provided to S&L, to detail capital expenditures broken down by economic industry and region. Pet. Ex. 4-R at 2. Mr. Thibodeau explained that S&L does not include any assumptions or considerations on wages or inflation in its analysis. Rather, wage and inflation assumptions were made as part of the capital cost estimates provided to S&L by CEI South. Additionally, Mr. Thibodeau said that IMPLAN contains its own internal database of wage and inflation projections for each industry. S&L did not independently consider any wage or inflation analysis in the reformatting for inputs provided to S&L into a format acceptable for IMPLAN. *Id.* at 3. He stated S&L considers the wages calculated from IMPLAN's results to be reasonable and that S&L expects the average wage of those involved in the technical oversight, design/engineering, and construction of the projects included in the TDSIC Plan to be above the overall median wage of the entire state and entire country. Furthermore, he stated these average wages are in-line with typical results of this type of analysis that S&L has performed and analysis conducted by other firms that S&L reviewed. *Id.* at 4.

iii. Incremental Benefits.

CEI South witness Rawlinson responded to OUCC witness Krieger's recommendation to disallow rate recovery for $85 million of Plan project estimates that Mr. Krieger said are not supported by "quantifiable benefits." He noted that the plain language of the TDSIC Statute requires CEI South to show that the "estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan." Ind. Code § 8-1-39-10(b)(3). Mr. Rawlinson posited that the incremental benefits analysis is on the plan as a whole, not on individual programs or projects as Mr. Krieger suggests. Further, Mr. Krieger's position assumes that CEI South must be able to quantify or monetize a benefit in order for it to be considered for purposes of the incremental benefits analysis. Mr. Rawlinson stated that is not accurate. He pointed out the TDSIC Statute does not use the word "quantifiable" or otherwise require that a benefit must be quantified in order for it to be considered a benefit of the overall Plan. Pet. Ex. 2-R at 2.

Mr. Rawlinson described the $85 million in investments Mr. Krieger identified that are not "quantified" with a benefit to cost ratio ("BCR") through the risk model provided by 1898 & Co. consisted of the wood pole replacements ($45M), capacity constraints and power quality projects ($26.3M), and physical security ($14M). Pet. Ex. 2-R at 2. Mr. Rawlinson disagreed with the OUCC's recommendation to disallow the $45 million of wood pole replacement investments included in CEI South's Plan. *Id.* at 3. He noted the TDSIC Statute allows for "projects that do not include specific locations or an exact number of inspections, repairs, or replacements, including inspection-based projects such as pole or pipe inspection projects, and pole or pipe replacement projects." Ind. Code § 8-1-39-2 (b)(1). Mr. De Stigter explained that the primary investment driver for this program is safety, reliability, and avoided cost. Even if there were no reliability or avoided cost benefits, the safety benefits alone fully justify this program. This program identifies, through inspection, defects in wood poles. If these poles are not replaced, there is a high likelihood they will fail in the near future exposing the general public to safety risks. Given the high safety issues, which is a key investment purpose outlined by the TDSIC Statute, Mr. De Stigter opined that the incremental safety benefits alone justify this cost. Pet. Ex. 3-R at 4.

With respect to the OUCC's recommended disallowance of the $26.3 million of capacity constraints and power quality projects included in CEI South's Plan, Mr. Rawlinson reiterated that these projects are required in order to mitigate against system capacity constraints and improve power quality. He explained that if CEI South does not mitigate against capacity constraints, there is risk of overloading equipment which could cause disruption to the Company's customers; therefore, the projects are required to meet current and future customer needs. Pet. Ex. 2-R at 4. Mr. De Stigter stated in rebuttal that the primary benefit for these investments is to meet CEI South's duty to serve obligation. As such, a quantified business case is not appropriate. Pet. Ex. 3-R at 4.

With respect to the OUCC's recommended disallowance of the $14 million of physical security upgrades, Mr. Rawlinson reiterated their critical role in protecting the public, CEI South employees, and physical assets. Pet. Ex. 2-R at 4. Mr. Rawlinson testified that each of the Programs the OUCC seeks to disallow generates benefits for continued service and the safety and security of the public, CEI South's employees, and its physical assets, although these benefits cannot always be quantified. For example, Mr. Rawlinson noted, it is nearly impossible to put a price tag on a human life. *Id.*

Mr. De Stigter explained on rebuttal that there is not a "one-size fits-all" approach to identifying system issues and the need for investment. Many tools and approaches need to be leveraged. Pet. Ex. 3-R at 2. He testified that each of the approaches used by CEI South to identify investments needs for the TDSIC Plan is appropriate given the system issues that they identify. *Id.* at 3. Mr. De Stigter's rebuttal testimony reinforced that it is not necessary to perform a quantified benefits assessment for all utility investments. He stated 1898 & Co. and CEI South evaluated all the projects and program types and identified the most appropriate benefits assessment to perform. *Id.* As it relates to the investments identified by CEI South System Stakeholders, it was determined that they did not need a quantified business case since their primary drivers are safety and to meet CEI South's duty to serve obligations with respect to system capacity issues. If electrical capacity constraints continue without being mitigated, Mr. De Stigter testified that infrastructure will become overloaded and burn. This causes outages for customers and more importantly can expose the general public to failed infrastructure, a safety issue. These drivers align to the TDSIC statute purpose. *Id.* at 4. Mr. De Stigter also noted that the Plan, as a whole, has quantified benefits that justify the cost, which is what the TDSIC statute requires the Commission to find. Mr. De Stigter reiterated the Plan's quantified benefit to cost ratio is 1.7. In other words, the quantified benefits are in excess of total Plan cost by a factor of 1.7. Given the qualitative factors of safety and duty to serve, Mr. De Stigter opined that this value is conservative for the Plan. *Id.* at 4-5.

iv. Reliability and Resilience.

Mr. Rawlinson responded to OUCC testimony calling into question CEI South's reliability metrics and improvement. He first explained that when reviewing reliability indices, performance must be evaluated across multiple years to understand trends. He testified that Reliability indices are driven by multiple factors, and CEI South's TDSIC investments do not directly target all outage causes. Pet. Ex. 2-R at 10. He stated external factors, such as weather, can have a significant impact on reliability indices, even with normalization techniques such as IEEE 1366 applied to the data. CEI South discussed the negative impacts of weather on electric reliability indices in its Electric Performance Report filed on June 27, 2022 in Cause No. 45564. As noted in the report, the number of Major Event Days ("MEDs") for 2018, 2019, and 2022 is similar, but the impact on the SAIFI and SAIDI for 2019 and 2022 is much more pronounced. Pet. Ex. 2-R at 10-11. Mr. Rawlinson testified that 44910 TDSIC Plan investments have impacted CEI South's reliability indices by reducing the number of system impacts due to equipment failures. *Id.* at 11.

v. TDSIC Filing Schedule.

Mr. Rawlinson testified on rebuttal that CEI South plans to continue filing its TDSIC rider on a semi-annual basis, as it currently does in the 44910 TDSIC Plan, updating for actual costs every six months through the semi-annual tracker filings. CEI South will include the actual completed costs of the projects, any variance commentary as required, as well as projects that move between planned years. CEI South will also include new best estimates of costs once per year in one of the semi-annual filings as it currently does in its 44910 TDSIC Plan. Pet. Ex. 2-R at 12. Mr. Rawlinson stated that the current filing schedule that CEI South uses allows the Company flexibility to include changes to the Plan while providing Plan updates in both semi-annual tracker filings. *Id.* He stated limiting CEI South to Plan updates only one time per year would restrict the Company's ability to respond to the potential changing needs of the system. *Id.* at 13.

vi. DER Deliverability.

Mr. Rawlinson rebutted CAC witness Inskeep's testimony regarding statements in CEI South's case-in-chief with respect to the benefit of hosting DER or EV projects. He noted that these benefits were not included in Petitioner's quantitative analysis. He testified, nevertheless, that as a secondary benefit, the projects proposed within the Plan will provide better opportunities for interconnection through equipment upgrades, capacity reconductors, and increased reliability through Distribution Automation. Pet. Ex. 2-R at 13.

vii. Substation Physical Security Improvements.

Mr. Freeman confirmed on rebuttal that CEI South plans to follow all applicable laws and regulations regarding video surveillance. He walked through the various applicable statutory requirements. He also described CEI South's action plan for physical security systems. Pet. Ex. 5-R at 2-3.

viii. Accounting Treatment.

Ms. Behme responded to OUCC witness Lantrip's recommendation to continue the depreciation expense accounting treatment that was settled in the Company's prior electric TDSIC plan approval proceeding (Cause No. 44910). She noted the accounting treatment granted in Cause No. 44910 was reached in settlement and that CEI South initially requested to include cost of removal in the accumulated depreciation balance. Pet. Ex. 6-R at 2. She explained that when the Company installs an asset that replaces an existing asset, it must also retire the existing asset. The accounting entry to retire the asset is to debit accumulated depreciation and credit utility plant in service for the original cost of the asset. This accounting retirement entry does not have an effect on net original cost rate base; however, the Company also must physically remove the retired asset. The net costs to remove the retired asset (net of salvage) are recorded by debiting accumulated depreciation. Ms. Behme explained in this way the cost of removing the retired asset does have an effect on net original cost rate base. *Id.* at 2. She said the Company's position is that these costs should be included in the calculation because they are necessary actual costs the Company must incur in order to complete the installation of the TDSIC projects that will replace the assets being retired.

Ms. Behme testified that the accounting treatment recommended by Mr. Lantrip does not allow CEI South to include the cost of removal within the accumulated depreciation balance, thus postponing recovery of that cost until the next base rate case. *Id.* She explained that including cost of removal within the accumulated depreciation balance allows CEI South to more accurately reflect and request recovery of the cost incurred for the TDSIC Plan's new capital investments. The cost of removal incurred by CEI South is a cost that pertains to the TDSIC Plan and should be included for timely recovery with all other TDSIC costs. *Id.* at 2-3. She said the Cause No. 44182 order Mr. Lantrip cited did not explicitly address cost of removal and should not be read as "uphold[ing] the exclusion of cost of removal." *Id.* at 3. She noted that in CEI South's most recent gas TDSIC case, the Company requested to include cost of removal within the accumulated depreciation balance for its TDSIC Plan. The OUCC did not oppose this request. The Commission approved CEI South's TDSIC plan for its gas business segment in Cause No. 45612. *Id.* (citing *S. Ind. Gas & Elec. Co.*, Cause No. 45612 (IURC Apr. 20, 2022)).

ix. *Affordability*.

Mr. Rice testified that the TDSIC Statute has two important provisions that help maintain affordability. First, as described by witness Steve Rawlinson, the estimated costs of the eligible transmission and distribution system improvements must be justified by incremental benefits attributable to the plan, as required under section 10(b)(3) of the TDSIC Statute ("Section 10(b)(3)"). Second, as described by Ms. Behme in her direct testimony, Ind. Code § 8-1-39-14(a) provides "the commission may not approve a TDSIC that would result in an average aggregate increase in a public utility's total retail revenues of more than two percent (2%) in a 12-month period." Pet. Ex. 7-R at 2. Mr. Rice said TDSIC's limit on the annual increase in a 12-month period produces more gradual increases in customer bills compared to large step changes in rates that may occur otherwise in a general rate case. Referring to the quantified financial benefits to customers presented in Company witness De Stigter's Table JDD-1, Mr. Rice explained that quantified benefits to customers are $681.3 million, which is more than the $404.6 million in planned investment in 2023 dollars. Mr. Rice stated these quantified financial benefits help with affordability in the long term. Pet. Ex. 7-R at 3.

Mr. Rice responded to Mr. Lantrip's allegations that he had misled the Commission in Cause No. 45836 that CEI South's rates had been surpassed by two other utilities. He stated fuel is a significant portion of the bill and that CEI South used the OUCC's own detailed calculations to show that CEI South did not have the highest bills at the time of that case. Their calculations, which were broken down by various components, transparently proved that CEI South did not have the highest bills at that time. *Id.* at 3. He noted that CEI South's customer bills have remained relatively flat, below inflation levels since 2011. He stated CEI South's residential bills have grown by only $9.90 (6.4%) in 12 years, or about 0.5% per year over this timeframe. *Id*.

Mr. Rice testified that Mr. Lantrip's presentation of recent CPCN filings related to generation transition and other recovery requests is an incomplete picture of future customer bills and is misleading. He stated Mr. Lantrip's presentation does not include O&M or fuel savings that result from these plant closures or savings associated with selling Renewable Energy Credits ("RECs") from the renewable projects CEI South is pursuing, all of which will help to offset individual impacts included in the Generation Transition Plan. Pet. Ex. 7-R at 4. Mr. Rice also stated Mr. Lantrip incorrectly double counted costs associated with purchasing temporary capacity, included in RCRA-21 in Cause No. 43406 currently before the Commission, needed to facilitate the construction of the A.B. Brown Combustion Turbines ("CTs") approved in Cause No. 45564. *Id.* He explained that once the new CTs are online, CEI South will not need temporary capacity, currently proposed in RCRA-21, to cover the capacity need created by the required closure of A.B. Brown Units 1 & 2 by October 15, 2023. Pet. Ex. 7-R at 4 (internal citations omitted).

Mr. Rice testified that affordability is always a priority in CEI South's Integrated Resource Plans ("IRP") and still is as CEI South executes on the first phase of the Generation Transition Plan, which includes securitization of A.B. Brown Units 1 & 2, recently approved by the Commission in Cause No. 45722. Pet. Ex. 7-R at 5. As described by witness De Stigter, this Plan is projected to provide customers more benefit in the long run than the cost of the total projects. Without continued investment in the Company's transmission and distribution, Mr. Rice opined that the financial burden will likely be higher. *Id.*

x. Timing of Filing.

At the outset of his rebuttal, Mr. Rice confirmed CEI South's intent to update cost recovery under the TDSIC Plan for base rate case elements such as return on equity and revenue allocation following the issuance of an order in the Company's upcoming general rate case. Pet. Ex. 7-R at 2. He stated CEI South will include a compliance filing to update the full capital structure and also back out investment through the rate base cutoff periods of the 2023 rate case. He opined that compliance filings are fast and efficient, as details are litigated in the rate case. *Id.* at 7. Mr. Rice disagreed that it would be "more reasonable and more efficient" to delay the TDSIC filing until after new base rates are fully established. *Id.* Additionally, Mr. Rice noted that CEI South's plan continues the same filing schedule and recovery schedule which the Commission, OUCC, and CEI South have efficiently worked through for nearly seven years. *Id.*

Mr. Rice responded to Mr. Lantrip's statements that CEI South is not correctly applying the TDSIC statute, explaining there appears to be some confusion about when the plan will start relative to the decision on the CEI South's upcoming rate case ("2023 rate case"). Mr. Rice testified that CEI South will begin incurring capital expenditures and TDSIC costs beginning just after January 1, 2024. CEI South will likely not receive an order in the 2023 rate case until November of 2024. Pet. Ex. 7-R at 5.

Mr. Rice walked through the proposed timeline, explaining that no later than December 31, 2023, CEI South will file for its next general rate case as required by the statute. Also, by the end of 2023, CEI South expects an order in the subject Cause. He said CEI South will begin incurring capital expenditures and TDSIC costs beginning just after January 1, 2024; in other words, on the week of January 1, 2024, the TDSIC Plan proposed in this case is expected to begin. CEI South will then file on August 1, 2024 to begin recovering 80% of the 45894 TDSIC revenue requirement between January 2024 and April 2024. In November 2024, CEI South anticipates an order in the 2023 rate case. Before that date, CEI South will have incurred costs related to this proposed TDSIC plan and will have deferred 20% pursuant to IC 8-1-39-9(c). And the order in the 2023 rate case will be "the next general rate case." Pet. Ex. 7-R at 5-6.

Mr. Rice stated CEI South reads Section 9 as providing that Petitioner should recover the 20% deferred at that point in the rate case to be decided next year. *Id.* at 6. In addition, at that time, any TDSIC spend through the end of the rate base cut off period will be included within base rates, and CEI South will do a compliance filing to remove this spend from the TDSIC rider pursuant to Ind. Code § 8-1-39-15. As further TDSIC projects are captured in later phases in the general rate case, the TDSIC will further be reset. It is anticipated that the remainder would stay in the TDSIC rider until being moved into base rates. No later than December 31, 2028, CEI South will file another general rate case as required by the TDSIC statute.

At that time, CEI South will propose to move any remaining TDSIC spend into base rates, both the 80% and 20% deferred. *Id.* at 6. Mr. Rice provided a timeline of the rate case as it relates to the TDSIC filings. *Id.* He pointed out that, assuming a project qualifies for TDSIC but is instead included within the rate case, this full investment, if approved by the Commission, would be 100% recovered from the customer in base rates when new rates go into effect. This is no different than including the 20% deferred when new rates go into effect. Nothing in the statute prohibits this from occurring. *Id.* at 7.

xi. Rate Design.

Mr. Rice responded to Mr. Inskeep's concerns related to rate design. He testified that Residential CEI South customers currently pay for a distribution component of TDSIC through a capped, fixed charge with costs in excess of the cap recovered on a per-kWh basis. Pet. Ex. 7-R at 8. He noted that today $6.00 (65%) of a residential customer's TDSIC charge is fixed. In comparison, by the end of the proposed plan approximately $9.00 (62%) of a residential TDSIC charge is projected to be fixed. *Id.* Mr. Rice testified that the residential customer class is relatively homogeneous, and thus a fixed charge is a reasonable alternative to demand charges, which are typically included in commercial and industrial rate structures. In any event, Mr. Rice noted the Company is going to file a general rate case before the end of the year. If the CAC believes a change in rate design for the TDSIC rider is warranted, that is the time to present that issue for consideration. Until a change, if any, is made as a result of the 2023 rate case order, CEI South is simply proposing to continue collecting TDSIC charges in the same manner as they are currently applied. *Id.*

5. Commission Discussion and Findings.

A. Statutory Requirements.

The TDSIC Statute permits a public utility to petition the Commission for approval of the public utility's plan for eligible transmission, distribution, and storage improvements. The Commission's order must include the following:

> (1) A finding of the best estimate of the cost of the eligible improvements included in the plan.
>
> (2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan.
>
> (3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.
>
> If the Commission determines that the public utility's TDSIC plan is reasonable, the commission shall approve the plan and authorize TDSIC treatment for the eligible transmission, distribution, and storage improvements included in the plan.

Ind. Code § 8-1-39-10(b).

"Eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that:

> (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas;

> (2) were not included in the public utility's rate base in its most recent general rate case; and
>
> (3) were [among other things] described in the public utility's TDSIC plan and approved by the commission under [Ind. Code § 8-1-39-10] and authorized for TDSIC treatment . . . .

Ind. Code § 8-1-39-2(a).

The term "eligible transmission, distribution, and storage system improvements" includes the following:

> (1) projects that do not include specific locations or an exact number of inspections, repairs, or replacements, including inspection-based projects such as pole or pipe inspection projects, and pole or pipe replacement projects; and
>
> (2) projects involving advanced technology investments to support the modernization of a transmission, distribution, or storage system, such as advanced metering infrastructure, information technology systems, or distributed energy resource management systems.

Ind. Code § 8-1-39-2(b).

Ind. Code § 8-1-39-7.8 requires that a TDSIC plan cover a period of at least five years and not more than seven years.

Ind. Code § 8-1-39-10(d) allows a utility to "terminate an existing TDSIC plan before the end of the original plan period by providing the commission a notice of termination at least sixty (60) days before the date on which the plan will terminate."

B. Petitioner's 2024 – 2028 TDSIC Plan. Petitioner requests approval of its TDSIC Plan pursuant to Ind. Code § 8-1-39-10. CEI South's five-year TDSIC Plan, covers the period of January 1, 2024 through December 31, 2028 and therefore meets the requirements of Ind. Code § 8-1-39-7.8.

C. Eligible Improvements Under Ind. Code § 8-1-39-2. CEI South's TDSIC Plan consists of approximately $454 million in proposed investments across seven different Programs: (1) Distribution 12kV Circuit Rebuild, (2) Distribution Underground Rebuild, (3) Distribution Automation, (4) Wood Pole Replacement, (5) Transmission Line Rebuild, (6) Substation Rebuild, and (7) Substation Physical Security. Pet. Ex. 1 at 6; Pet. Ex. 2 at 8.

The record reflects that the improvements, upgrades and, in some cases, new technologies and/or approaches included in the TDSIC Plan were selected by CEI South to preserve and further enhance system safety, reliability and resiliency with an aim of reducing the likelihood of equipment failures and unplanned outages. Pet. Ex. 1 at 6; Pet. Ex. 2 at 7-8.

The record also reflects that none of the TDSIC Plan investments and costs are currently reflected in CEI South's rate base in its most recent base rate proceeding (Cause No. 43839, Order issued April 27, 2011). Pet. Ex. 2 at 16.

CAC raised concerns about Petitioner's unverifiable, unsupported claims about the benefits of its TDSIC Plan for distributed generation, including that:

- The TDSIC Plan would help with renewable energy and distributed generation deployment.[2]
- The Distribution Automation scheme "can assist DER applications to come back online quicker."[3]
- "Distributed Energy Resources could potentially push electricity onto our transmission system,"[4] an unlikely scenario given the relatively modest distributed generation adoption rates in CenterPoint's service area and current interconnection standards designed to ensure distributed generation facilities can safely interconnect.
- That FERC Order 2222 would require "a host of monitoring and control systems" without offering an explanation as to what monitoring and control systems were needed. CenterPoint also failed to note that FERC Order 2222 would not be implemented until well *after* its TDSIC Plan, in late 2029, as currently proposed by the Midcontinent Independent System Operator.

CAC noted in testimony that when CAC attempted to get the most basic information on customer adoption of DER technologies to verify whether growing customer adoption of DER technologies was substantial enough to warrant large utility investments, Petitioner objected and refused to answer the data request.[5] We find this concerning and note that this weighs against Petitioner's proposal.

While ~~No~~ no party disputed ~~and we now find~~ that the Programs included within CEI South's TDSIC Plan are "eligible transmission, distribution, and storage system improvements" within the definition set forth in Ind. Code § 8-1-39-2, we urge Petitioner to cooperate in discovery and support any claims it makes with respect to TDSIC projects. We approve these programs only because ~~because~~ CEI South also says it is undertaking them for the purpose of safety, reliability, or system modernization and they were not included in CEI South's rate base in its most recent general rate case. *See* Pet. Ex. 2 at 9. We find Petitioner's claims as noted above discouraging and advise Petitioner against making such unsubstantiated statements in the future.

Petitioner's proposed Wood Pole Replacement investments included in the Plan fit within Ind. Code § 8-1-39-2(b)(1) which allows for "projects that do not include specific locations or an

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[2] *See* Rawlinson Direct Testimony, p. 13, lines 9-10, stating "The Company's TDSIC Plan will increase and continue to advance the electric grid design to support renewable investments by the state and by customers."
[3] Rawlinson Direct Testimony, p. 13, lines 13-14,
[4] Rawlinson Direct Testimony, p. 13, lines 17-18.
[5] CenterPoint Response to CAC Data Request 1-012 (CAC Ex. 1, Attachment BI-2).

exact number of inspections, repairs, or replacements, including inspection-based projects such as pole or pipe inspection projects, and pole or pipe replacement projects."

D. **Best Estimate of the Cost of Eligible Improvements.** Ind. Code § 8-1-39-10(b)(1) requires that an order approving a TDSIC plan must include a finding that the cost of the TDSIC plan represents "the best estimate of the cost" of the proposed eligible improvements contained therein.

Petitioner's witnesses Leger and Rawlinson explained that CEI South engaged with both internal and external subject matter experts to arrive at the cost estimates and that, with the exception of the Wood Pole Replacement Program and the five Substation Physical Security Surveillance System Projects, each Project within the complete TDSIC Plan was estimated to follow the recommended practices of AACE, with Projects planned to be completed in the first two years of the TDSIC Plan designed to AACE Class 2 criteria and the remaining projects designed to AACE Class 4 estimate criteria. Pet. Ex. 1 at 9.

Mr. Rawlinson presented the estimated cost of the TDSIC Plan. He said CEI South has created a detailed cost estimate for each Project, including PSPs, for all Programs within the TDSIC Plan except the Wood Pole Replacement Program and the five Projects in the Substation Physical Security Program. The Wood Pole Replacement Program and Substation Physical Security Surveillance System Projects do not represent a specific location and therefore have an estimated cost at the Program level by planned year but do not have unique projects identified with an associated estimated cost for this filing. For all other projects, each detailed cost estimate includes a line-item breakdown of the cost including engineering, contract labor, material, construction and material loadings, land, easements, and survey work as applicable. Escalation and contingency were included in the total best estimate. *See* Pet. Ex. 2 at 28-29.

OUCC witness Krieger asks this Commission to require Petitioner to provide "more appropriate and more accurate" project estimates, making use of AACE Class 1 and Class 3 estimates instead. Pub. Ex. 2 at 5-7. He accepted a Class 4 level estimate for the Substation Physical Security improvements alone (though ultimately recommended disallowance of these improvements as discussed below). Mr. Krieger also took issue with the way Petitioner built contingency, overhead, and escalation amounts into the best estimate of costs.

Witness Krieger's request regarding the AACE class level of the estimates is inconsistent with our prior TDSIC Orders. For instance, in CEI South's current gas TDSIC, the level of AACE class estimate is less precise to that for its proposed electric TDSIC plan: Class 2 estimates only for the projects during the first year, with Class 4 estimates for the later years; yet we found this level of precision to be sufficient for the beset estimate. *Southern Ind. Gas & Elec. Co. (d/b/a CEI South),* Cause No. 45612 (IURC 4/20/2022), pp. 15 and 18, 2022 WL 1266292, *15 and 18. For the electric industry, we also have recently approved AACE class level estimates that are less refined than those presented here. *Northern Ind. Pub. Serv. Co*. Cause No. 45557 (IURC 12/28/2021), p. 56, 2021 WL 6135480, * 59, *aff'd* 197 N.E.2d 306 (Ind. Ct. App. 2022), *trans. pending on other grounds* (Class 3 estimates for the first 18-24 months with later years being Class 4 or Class 5 estimates). We find that Class 2 and Class 4 estimates balance a reasonable level of work scope detail, estimate accuracy, and engineering resources. This level of detail is consistent with the requirements of the TDSIC Statute, our prior findings in TDSIC proceedings, and the determination of the "best estimate" of the costs.

When determining whether a utility has presented the best total cost estimate of project costs under the TDSIC Statute, this Commission has repeatedly found that inclusion of contingency is necessary to be considered the "best estimate" of costs of eligible improvements. For example, in Cause No. 45612 related to CEI South's Gas CSIA/TDSIC Plan, in response to challenges about the inclusion of contingency as part of project cost estimates from certain parties, this Commission found that the inclusion of contingency is "reasonable and appropriate in establishing a best cost estimate . . . ." *CEI South,* Cause No. 45612, at p. 16, 2022 WL 1266292, *16. Similarly, in two 2020 orders, the Commission found that "the exclusion of contingency in the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute." *Northern Ind. Pub. Serv. Co.,* Cause No. 45330 (IURC 7/22/2020), p. 23, 2020 WL 4226560, *25; and *Indianapolis Power & Light Co.,* Cause No. 45264 (IURC 3/4/2020), pp. 22-23, 2020 WL 1232325, *23 (same), *aff'd,* 159 N.E.3d 617 (Ind. Ct. App. 2020). In Cause No. 45330, the Commission also found that "the level of contingency reflected in [NIPSCO's] cost estimates is reasonable." *NIPSCO,* at p. 23, 2020 WL 4226560, *25.

The use of contingencies is standard practice throughout the utility industry to capture costs for unknowns which often occur and is required for the Company to create the best estimate of costs of eligible improvements. In order for CEI South to submit a best estimate of the cost, contingency has to be included. Submitting a best estimate is required by the TDSIC Statute.

In responding to OUCC witness Lantrip's recommendation of a flat 10% contingency, Mr. Rawlinson explained that a flat 10% contingency rate for all 5 years of the plan would not account for the difference in accuracy between a Class 2 and Class 4 estimate. With respect to contingency, he explained the contingency applied to projects was based on the amount of detail and confidence in the scope of work and design to ensure accurate estimates were developed for projects. CEI South used 12.5% contingency on projects in years 2024 – 2025 and 17.5% contingency on projects for years 2026 – 2028 and PSPs. Pet. Ex. 2 at 26. We find that Petitioner's contingency is in line with other recent orders and appropriately differentiates between Class 2 estimates for the first two years of the Plan as compared to the Class 4 estimates for the outer years of the Plan. The evidence shows that the level of contingency being proposed is below the levels included in CEI South's current approved electric TDSIC plan (Cause No. 44910) (15% for the first three years and 25% for the remaining years). Pet. Ex. 2-R at 8. Accordingly, we find Mr. Lantrip's recommendation of a flat 10% contingency is unreasonable and it is hereby rejected.

Petitioner also applied 4% escalation to account for inflation of materials, labor, and services. Pet. Ex. 2-R at 9. The OUCC recommended a 3% inflation rate based on the Bureau of Labor Statistics inflation rate for consumer goods and services for the year ended June 2023.

Escalation is a provision in estimates to account for changes in market or economic conditions over time and is both a component of cost estimating and to a lesser extent, risk mitigation. Specifically, escalation is an accepted method of modifying an estimate in today's – or some other specified year's – dollars to reflect the expected estimate in a future year. As such, CEI South's objective in using the escalation factor was to provide more accurate estimates for work orders in later years. Pet. Ex. 2-R at 9. CEI South worked with 1898, who utilized various economic, and inflation forecast information, to determine the escalation rate at 4% per year starting in 2024 through 2028. Pet. Ex. 2-R at 26. CEI South's rebuttal evidence showed that, based on the Handy-Whitman Index, escalation on a 5-year rolling average basis aligns with CEI South's 5-year plan and is consistent with this rate. *See* Pet. Ex. 3-R at 6. We find this rate to be appropriate.

As with contingencies, the Commission has recognized escalation as a component of a best estimate. In the Orders in Cause Nos. 45611 and 45612, we found the inclusion of escalation on the contingency amounts for CEI North's and CEI South's TDSIC Projects, respectively, is reasonable. *Ind. Gas Co., Inc. (d/b/a CEI North)*, Cause No. 45611 (IURC April 20, 2022), pp.17-18, 2022 WL 1266290, *18; *CEI South*, Cause No. 45612, p. 17, 2022 WL 1266292, *18. The record reflects that CEI South's practice and methodology for contingencies and escalation in this case is consistent with those gas TDSIC cases. Accordingly, CEI South's use of contingencies and escalation to provide more accurate estimates is consistent with prior findings of this Commission.

It is also common in the utility industry that certain indirect costs related to engineering, supervision, general corporate and various administrative functions are capitalized to construction projects. "[O]verhead costs are indirect actual costs associated with executing capital construction work. Because they are related to, and a portion of the actual project cost, we find the inclusion of overhead costs on base project costs with contingency is appropriate and reasonable for both Petitioner's Compliance and TDSIC Projects." *CEI South,* Cause No. 45162, pp. 17-18, 2022 WL 1266292, *18. Indirect capital costs are a component of the "best estimate" as required by the TDSIC Statute. These are costs associated with executing capital construction work, but they cannot be easily quantified in discrete dollar amounts for each individual project. It is accepted practice to allocate a percentage of these costs to each project estimate, regardless of whether the estimate is a Class 2 or Class 4. We disagree with the OUCC's suggestion that Petitioner's application of 12% overhead is erroneous or otherwise inappropriate.

Thus, we find applying overhead and escalation on top of contingency as Petitioner has done in its cost estimates is required to produce a "best estimate" and should be approved.

Based on the evidence presented, we find that Petitioner's TDSIC Plan is consistent with the "best cost estimate" requirements.

We find Petitioner's cost estimate of $454 million for its TDSIC Plan projects as presented on Table SRR-1 in Petitioner's Exhibit 2 at 21 and Attachment SRR-1 (Confidential) is a "best estimate" of the eligible improvements included in the Plan and should be approved.

E. <u>Public Convenience and Necessity</u>. Ind. Code § 8-1-39-2 defines eligible transmission, distribution, and storage system improvements as projects undertaken for purposes of safety, reliability, system modernization, or economic development.

Petitioner's witnesses identified several aspects of the TDSIC Plan that would benefit the public. Mr. Rawlinson testified that the eligible improvements included in the 2024 – 2028 TDSIC Plan are required or will be required to maintain the safety, integrity, and reliability of CEI South's transmission and distribution systems consistent with the public convenience and necessity. Pet. Ex. 2 at 37. With respect to the Substation Physical Security programs that the OUCC seeks to exclude, Petitioner's witness Freeman offered testimony showing the purpose of these projects is to add additional security control measures at the Company's substations to prevent a physical attack on those assets. Pet. Ex. 5 at 7. The evidence shows attacks on substations are a serious threat to the lives of many due to their impact on the reliability of the electric grid. *Id.* at 5. Due to the inherent risk of severe injury or death due to a trespasser entering a substation, these added controls increase public safety. Further, these added controls will help protect system reliability.

No party offered evidence demonstrating that the TDSIC improvements included in the TDSIC Plan were unnecessary for the continued safe and reliable service to customers, or that the public convenience and necessity did not, or would not, require the TDSIC investments to be made.

Ind. Code § 8-1-2-4 requires Petitioner to provide reasonable and adequate service to customers. Safety and reliability are the first two objectives listed in the TDSIC Statute for "eligible transmission, distribution, and storage system improvements." Ind. Code § 8-1-39-2(a)(1). Based on the evidence presented, we find that Petitioner has sufficiently supported that the investments described in its TDSIC Plan are reasonably necessary for CEI South to continue to provide reasonable and adequate retail service to the customers in its service territory. Therefore, we find that the public convenience and necessity requires or will require all of the eligible improvements included in the TDSIC Plan.

F. Incremental Benefits Attributable to the TDSIC Plans.

Ind. Code § 8-1-39-10(b)(3) requires the Commission to determine whether the estimated cost of the eligible improvements included in the TDSIC Plan are justified by the incremental benefits attributable to the TDSIC Plan.

The approach to developing the Plan as reflected in Petitioner's evidence supports our finding that the Plan investments will provide value to CEI South's customers and other grid stakeholders. Petitioner's witness De Stigter showed that the business case for the Plan is robust from several perspectives. Pet. Ex. 3 at 7. We find that based on the evidence in the record, the Plan as a whole has quantified incremental benefits in excess of eligible investment improvements and that, as a result, the incremental benefits attributable to the Plan justify the estimated costs of the eligible improvements included in the Plan. It has been the Commission's position that this finding is what is required by Ind. Code § 8-1-39-10(b)(3). We acknowledge, however, that the question whether the incremental benefits of each individual project must justify the costs of that project (rather than the incremental benefits of the plan as a whole) is currently being considered by the Indiana Supreme Court. *Office of Util. Cons. Couns. v. Duke Energy Indiana,* 205 N.E.2d 1026 (Ind. Ct. App. 2023), *trans. granted.*

The Court's ultimate determination on that question, however, has no bearing on the instant case, because we also find that Petitioner has shown that all individual projects included in the TDSIC Plan have incremental benefits that justify their cost. As explained by the Indiana Court of Appeals in reviewing the IPL TDSIC plan, neither "incremental" nor "benefits" is defined in the TDSIC Statute and, therefore, ascribing the "plain, ordinary and usual meaning" to these terms, "benefit" means "'something that guards, aids, or promotes well-being;' while 'incremental' means 'something that is gained or added.'" *IPL Industrial Group v. Indianapolis Power & Light Co.,* 159 N.E.3d 617, 626 (Ind. Ct. App. 2020) (quoting dictionary definitions). These definitions do not require a monetary quantification demonstrating that dollar values of benefits exceed dollar values of costs. Rather, if the Indiana Supreme Court holds that Section 10(b)(3) requires an evaluation of each individual project's incremental benefits, we would review whether the project "gain[s] or add[s]" "something that guards, aids or promotes well-being" which justifies that project's costs.

Applying this test, all of the projects included in CEI South's Plan pass. The record is clear that for those projects evaluated using the risk and resiliency project identification process, their quantified incremental benefits justify their cost. *See* Pet. Ex. 3 at 37-38. The only projects in dispute are those for which a dollar value quantification and comparison to costs could not be done. The largest share of the projects in dispute are the Wood Pole Replacement Program and its associated projects (approximately $45 million). Pet. Ex. 2-R at 2. Next is the Substation Physical Security Project (approximately $14 million). *Id.* The remainder is an assortment of projects. This included (1) Transmission Line Rebuilds, (2) Substation Rebuild and (3) Distribution 12kV Circuit Rebuilds (in total, approximately $26.3 million). *Id.*; Pet. Ex. 3-R, at 2. Each of these projects in dispute has significant alignment to CEI South Plan Objectives and TDSIC Purposes and they add "something that guards, aids or promotes well-being." The OUCC agreed that "[r]eliability and resilience are absolutely critical" and that "[s]afety projects are crucial to reliability and resilience." Pub. Ex. 2 at 3 and 9. The incremental benefits from the Transmission Line Rebuild, the Substation Rebuild, and the Distribution 12kV Circuit Rebuild are to deliver service safely and to support CEI South's duty to serve. Each of these projects mitigate against system capacity constraints and improve power quality. Without these projects, there is risk of overloading equipment, causing it to burn or disrupt, also presenting a safety concern. The projects in the Wood Pole Replacement Program also support the duty to serve and maintain reliability. Further, it presents a substantial safety incremental benefit. Substation Physical Security protects against intentional acts of vandalism, theft or terrorism and thus provides the incremental benefit of maintaining service and protecting public safety. Each of the incremental benefits of these projects justifies the costs of the project and thus satisfies the Section 10(b)(3) requirement. We agree with CEI South witness De Stigter that these qualitative factors should not be ignored or dismissed, specifically for safety mitigation. They are a key part of the overall business case and their existence renders the quantified business case for the TDSIC Plan conservative where it does not include the obvious and tangible benefit streams for safety risk mitigation or the other CEI South objectives. *See* Pet. Ex. 3 at 33, 37-38.

Based on the evidence presented, we find that Petitioner has sufficiently demonstrated that the estimated costs of the TDSIC Plan's eligible improvements are justified by the incremental benefits attributable to the Plan. This finding remains true whether the incremental benefits are viewed from the plan as a whole or whether the incremental benefits of each distinct project are considered. As noted earlier, the vast majority of Petitioner's TDSIC Plan investments are for safety and reliability projects. In determining the eligible improvements to be included in the TDSIC Plan, Petitioner employed a robust process to identify and prioritize the projects in alignment with the purposes set forth in the definition of eligible improvements under the TDSIC Statute. The evidence shows Petitioner's TDSIC Plan will enhance customer and employee safety, avoid outages, preserve and improve operational integrity, and support economic development.

G. **Reasonableness of TDSIC Plan.** Based upon our review of the evidence, the Commission finds Petitioner's TDSIC Plan is reasonable and should be approved as set forth herein. Petitioner's TDSIC Plan appropriately and reasonably addresses Petitioner's aging infrastructure through projects intended to enhance, improve, and replace system assets for the provision of safe and reliable electric service. These are activities from which customers are reasonably expected to benefit.

In an apparent effort to call into question the reasonableness of CEI South's TDSIC Plan, the OUCC and CAC raised concerns about affordability. Petitioner responded to those concerns, pointing out errors in the OUCC's presentation of its rates. We find there are safeguards built into the TDSIC Statute that help maintain affordability. First, the estimated costs of the eligible transmission and distribution system improvements must be justified by incremental benefits attributable to the plan, as required under Section 10(b)(3) of the TDSIC Statute. Second, Ind. Code § 8-1-39-14(a) requires "the commission may not approve a TDSIC that would result in an average aggregate increase in a public utility's total retail revenues of more than two percent (2%) in a 12-month period." The limit on the annual increase in a 12-month period produces more gradual increases in customer bills compared to large step changes in rates that may occur otherwise in a general rate case. We have found elsewhere in this Order that both of these provisions are satisfied by CEI South's TDSIC Plan. We are sensitive to the concerns of affordability of ratepayers in the State of Indiana. However, we find that CEI South's use of the TDSIC mechanism can help to mitigate the impact of the investments we have already found serve the public convenience and necessity.

H. Updates to the TDSIC Plan. Ind. Code § 8-1-39-9(b) requires that a public utility update its TDSIC plan at least annually as a component of the TDSIC periodic automatic adjustment filings.

In accordance with Mr. Rawlinson's and Mr. Rice's testimony, and consistent with Petitioner's previous TDSIC mechanism, the Commission finds it reasonable that Petitioner makes its TDSIC filings every six months. Pet. Ex. 2 at 34-35; Pet. Ex. 7 at 7. In the semi-annual filings, CEI South proposes to include the actual completed costs of the projects for the current filing period and any variance commentary as required. Pet. Ex. 2 at 34. CEI South also proposes to update the TDSIC Plan at least once a year to include potential changes to the Plan that include new best estimate of costs as well as information related to projects that are moving between plan years, or projects that are moving in or out of the Plan. The Company proposes to adjust project estimates once per year in one of the semi-annual filings. *Id.* at 35.

The OUCC's suggested alternative to this update process would unnecessarily restrict the Company's ability to respond to the potential changing needs of the system by limiting plan updates to one time annually. *See* Pub. Ex. 1 at 22.

We find Petitioner's proposed update process to be reasonable and consistent with the process used for its 44910 TDSIC Plan. This process has worked well in CEI South's previous TDSIC filings, and we find that this process will reasonably balance the needs of Petitioner for investment recovery confidence and customers for prudent investment assurance.

I. TDSIC Mechanism. Consistent with the terms of Petitioner's previous TDSIC Order, Petitioner has proposed to recover 80% of the costs associated with the TDSIC

Plans through its electric TDSIC rate adjustment mechanism. We will discuss the OUCC's and CAC's specific concerns in the following sections.

Ultimately, and consistent with our findings below, we authorize Petitioner to continue using the TDSIC mechanism established in Cause Nos. 44910 for recovery of 80% of the TDSIC Project costs. In its tracker filings under Ind. Code § 8-1-39-9(a) Petitioner shall file with the Commission's Energy Division a revised tariff sheet consistent with the format set forth on Attachment MAR-2, as well as with our findings below.

*i. Customer Class Revenue Allocation***.**

Petitioner proposes to use the allocation percentages agreed to by less than all the parties in the Cause No. 44910 Settlement until such time as the percentages are updated in a future rate case. The allocators established in that disputed Settlement were approved by this Commission in order to address the move of a large customer and better represent cost causation than the allocators established in 2011 under the 43839 Order. CAC noted concern about how CenterPoint's proposed residential cost allocation (42.62% of transmission costs and 58.44% of distribution costs) could change as a result of its forthcoming electric rate case. If allocation factors adopted in that rate case increase the proportion of TDSIC costs allocated to the residential class, the residential bill impact of the TDSIC Plan will be even higher than currently estimated. ~~witness Inskeep opposed CEI South's proposed cost allocation.~~ CAC Ex. 1 at 8~~5~~.

We find a continuation of the current revenue allocation under Petitioner's TDSIC until new allocation percentages can be determined through the upcoming base rate case is reasonable. There will be an opportunity in the upcoming rate case to examine and, if warranted, modify the customer class allocations. We provide guidance, however, that Petitioner should consider the impact to residential customers, in particular, in the forthcoming rate case to ensure they are protected from greater allocations of these TDSIC costs.

Based upon our review of the evidence, we find that the allocation methodology proposed by the Petitioner is a reasonable approach consistent with the TDSIC Statute and should be approved for the TDSIC.

*ii. Rate Design***.**

Petitioner is proposing the same rate design previously approved in Cause Nos. 44910, a case that was settled by less than all the parties. In 44910, certain parties agreed to Petitioner's proposal ~~including~~ that TDSIC costs be recovered from residential customers via a fixed monthly charge and from all other customers using a volumetric charge. Pet. Ex. 7-R at 8. Our decision to approve that settlement does not mean this is a decided issue in the present case.

CAC ~~witness Inskeep disagreed~~brought forth valid concerns with Petitioner's proposal~~, asserting that it is not reasonable~~ to include a fixed monthly charge for residential customers for distribution costs related to TDSIC. CAC Ex. 1 at 8-9. First, CAC noted how Petitioner is not proposing equitable recovery across its customer classes. CenterPoint is proposing to charge medium and large commercial and industrial customers a per-kW or per-kVA charge, while it is proposing fixed charge recovery from residential customers. Petitioner's arguments rest on the fact that it is currently authorized to charge ~~Mr. Rice responded that Residential CEI South customers currently pay for~~ a distribution component of TDSIC through a capped, fixed charge with costs in excess of the cap recovered on a per-kWh basis~~.~~ (Pet. Ex. 7-R at 8~~.~~). We do not find this argument compelling enough to continue this practice, particularly given the severity of the fixed charge rising from ~~The record reflects that today~~ a $6.00 (65%) fixed charge for the ~~of a residential customer's~~ TDSIC charge ~~is fixed~~to $9.00~~. B~~ by the end of the proposed TDSIC Plan ~~approximately $9.00 (62%) of a residential TDSIC charge is projected to be fixed~~. *Id.*

While we agree that customer-related costs, or costs that are based on the number of customers on the utility's system, are appropriate to collect through a fixed charge, Petitioner takes this too far. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual defines customer costs as "directly related to the number of customers served."[6] It provides that customer-related costs should be "[a]llocated among the customer classes on the basis of the number of customers or the weighted number of customers."[7] These costs can be contrasted against costs that vary based on the amount of energy a customer consumes or when the customer consumes.

While we understand that utilities like Petitioner would prefer to collect as much revenue as possible through fixed charges on residential and small commercial customers because that stabilizes their revenue (in contrast to variable charges that provide varying levels of revenue month-to-month and season-to-season as usage fluctuates), that does not mean that a fixed charge is the most appropriate rate design for recovering a particular type of cost, or that it sends appropriate price signals and is fair to customers.

We agree that the costs of metering, billing and collection, and customer assistance are customer costs.[8] But leading experts have demonstrated that collecting distribution equipment through a fixed charge is not economically efficient or cost based and can cause undesirable rate cross-subsidies, such as renters subsidizing homeowners.[9] Accordingly, they advise that the fixed charge should not exceed the customer-specific costs attributable to an incremental consumer. We agree and find it inappropriate for CenterPoint to recover 100% of its TDSIC Plan distribution costs through a fixed charge.

[6] NARUC Electric Utility Cost Allocation Manual, January 1992, at 20.
[7] P. 22; *see also* pp. 98-99.
[8] "The customer service and facilities function includes the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection, and customer information and services. These investments and expenses are generally considered to be made and incurred on a basis related to the number of customers (by class) and are therefore of a fixed overhead nature." *See* National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January, 1992 (hereinafter "NARUC Electric Manual"), at 20, 89.
[9] *See, e.g.,* Jim Lazar and Wilson Gonzalez, "Smart Rate Design for A Smart Future," July 2015, p. 9, stating, "Although some utilities and regulators use customer charges to recover distribution system costs, this paper demonstrates that this is neither cost-based nor economically efficient. High customer charges impose unfair costs on small-use residential consumers, including most low-income household and apartment residents."

In fact, we find it is unusual for an electric utility to increase its fixed charges on residential customers outside of a base rate case. Although we approved the settled 44910 case that allowed for this, we now find and affirm that cost recovery approved outside of a rate case (e.g., through a rider or tracker) for residential customers is and should nearly always be through variable per-kWh charges, regardless of whether it is for generation, transmission, or distribution system investments, making Petitioner's proposal here an outlier.

Petitioner acknowledges that customers with higher or growing demand put additional strain on the distribution system, which can lead to the need for upgrades and expansions, resulting in additional capital and operating costs ultimately borne by customers. It states in discovery that:

> Design of transmission and distribution infrastructure to meet customer service and reliability standards entails anticipating peak usage of the infrastructure. The most equitable means to charge those customers causing the peak infrastructure demand to be incurred is through a demand charge. Investments in distribution infrastructure should be recovered from the customers who cause those investments to be made …

CAC Ex. 1, Attachment BI-1 (Petitioner Response to CAC Data Request 1-10). In other words, Petitioner admits that the distribution costs included in the TDSIC Plan do not vary by the number of customers, but rather by the demands placed on the distribution system by customers. Yet, Petitioner goes on in the same response to state that "once such investments are made then the appropriate price signal is to recover those fixed costs through fixed charges or demand-based charges." We find that such a claim is not supported by economic principles, rate design principles, or the NARUC Electric Utility Cost Allocation Manual; thus, Petitioner should recover distribution costs on the basis of customer end-use consumption. This also produces beneficial and more appropriate price signals, as it allows customers to reduce their total charges by reducing their usage, which can help reduce strain on the distribution grid.

While Petitioner may believe distribution costs are "fixed costs," we find this is neither accurate nor relevant in determining the appropriate rate design. All costs, including distribution system costs, are actually variable in the long run. As Petitioner noted in the quoted discovery excerpt above, these costs are not actually fixed, but are related to the demand placed on the distribution system; reduced demand would therefore result in reduced distribution system costs being incurred in the future. We find that rate design should be fashioned with establishing appropriate price signals for consumers. Here, incentivizing consumers to use less electricity by collecting TDSIC Plan charges exclusively through variable per-kWh charges would also encourage those same customers to reduce peak demand, as many actions consumers take to reduce kWh consumption also reduce peak demand (e.g., purchasing more energy efficiency appliances and fixtures like low wattage lightbulbs; behavioral responses like setting thermostats to higher temperatures in the summer). The distinction between fixed and variable costs faced by the utility is also not particularly relevant for rate design, as there is no economic rationale for collecting what the analyst deems to be "fixed costs" through "fixed charges." For more than a century, utilities have been collecting an assortment of large "fixed costs," for generation, transmission, and distribution system investments primarily through variable – not fixed – charges on customers. There is no reason to change that model now. Indeed, while Mr. Rice provided testimony that the residential customer class is relatively homogeneous, and thus a fixed charge is a reasonable alternative to demand charges, which are typically included in commercial and industrial rate structures, if Petitioner actually believed its argument, it would have also proposed collecting 100% of its transmission system costs and 100% of distribution system costs allocated to medium and large commercial and industrial customers through fixed charges. It would also propose to collect most generation plant costs through a fixed charge, as power plant costs are "fixed" in the short run. Obviously, such an outcome is absurd on its face, as it would likely lead to $100+ per month fixed charges on residential customers, and consumers would never have a meaningful incentive to conserve electricity to help reduce generation, transmission, and distribution system costs over the long run.

Collection through per-kWh charges instead of Petitioner's proposed fixed charges for residential and commercial customers would not harm Petitioner since it would recover the same amount from customers. There is also a cost reconciliation mechanism in the TDSIC tracker, so even if Petitioner experienced a temporary shortfall in the collection of revenues, that shortfall would be trued-up with ratepayers. We find Petitioner's proposal to recover 100% of its distribution costs allocated to residential customers through a fixed charge absurd on its face and deny this cost recovery proposal. While the TDSIC Plan does not represent all of Petitioner's annual distribution costs, it does span a broad variety of types of distribution costs, ranging from substation rebuilds and physical security, to Distribution Automation, to rebuilding 12kV circuits.

CAC presented compelling evidence and authority that the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts requires separate accounts for distribution investment (accounts 360-373) and expenses (accounts 580-598). The NARUC Electric Utility Cost Allocation Manual clearly identifies that at all or portions of most of these accounts are demand-related.[10] It also repeatedly emphasizes that careful study (which the record shows Petitioner did not do in this case) is needed to appropriately allocate distribution costs between demand-related and customer-related (although many utility regulators have moved away from allocating any or most distribution costs as customer-related, as detailed further below). For example, it states that "[t]he amounts between classifications [customer-related and demand-related] may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components."[11] It goes on to say:[12]

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both.… Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation.

[10] Pp. 87-88.
[11] Footnote 2, pp. 87 and 88.
[12] P. 89.

Again, the record shows that Petitioner did not perform the analysis referenced in the NARUC Electric Utility Cost Allocation Manual to determine the nature of distribution plant and expenses to ensure costs are assigned correctly.

To explain further, Petitioner's TDSIC Plan includes both a Substation Rebuild Program and Substation Physical Security Program that have distribution-allocated components. These costs do not vary by the number of customers. For example, adding an additional residential customer would not result in any added physical security costs to the substation. The NARUC Electric Utility Cost Allocation Manual specifically notes that:[13]

> Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. **The reason is that costs are incurred to serve area load, rather than a specific number of customers**. Distribution substations costs (which include Accounts 360-Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because **substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.**

(Emphasis added.) ***The NARUC cost allocation manual goes on to detail several possible methodologies for determining the portion of distribution costs that should be allocated as customer-related and demand-related, a step that CenterPoint did not follow.*** Since substation costs included in the TDSIC Plan are to serve load and are not affected by the number of customers to be served, these costs should not be recovered through a fixed charge.

We are also concerned when reviewing how Petitioner's proposed residential monthly fixed charge compares to other Indiana electric investor-owned utilities ("IOU"). As shown in CAC Ex. 1, Figure 2, Petitioner's proposed fixed component of the TDSIC tracker combined with its customer charge established in base rates would result in it going from the second-least expensive base fixed charge to the most expensive total fixed charge among Indiana's five electric IOUs. Any increase in Petitioner's fixed customer charge arising from its forthcoming electric rate case would be additional. If we were to approve this, Petitioner's total residential fixed charge would be among the most expensive of any electric IOU in the U.S. In fact, if approved, Petitioner's fixed charge would have the 10th-highest total residential fixed charge out of 171 U.S. investor-owned electric utilities. We also consider the fact that Petitioner's proposed fixed charge cost recovery mechanism is inconsistent with how other Indiana investor-owned utilities recover TDSIC distribution costs; AES Indiana, Duke Energy Indiana, and NIPSCO all recover these costs through per-kWh charges on residential customers.

High residential fixed charges have numerous, substantial drawbacks compared to cost recovery through variable per-kWh rates—drawbacks which Petitioner has not adequately rebutted. These drawbacks include reduced customer control, the disproportionate impact to low usage and low income customers, reduced financial viability of deploying energy efficiency and

[13] P. 90.

distributed generation, and higher electric system costs. At the field hearing, Petitioner's customers largely testified in opposition to this cost recovery mechanism in particular. Petitioner's customers expressed concerns about the ability to afford their electric bills generally. We find their testimony weighs against approval of recovery through the fixed charge.

We note too that many state utility commissions have approved methods of calculating the residential fixed charge that do not classify distribution system equipment upstream of the service line as a customer cost, including Illinois, Missouri, Texas, Arkansas, Idaho, Washington, Connecticut, Rhode Island, Maryland, and Colorado. CAC Ex. 1, pp. 19-20.

In conclusion, ~~We~~ we find Petitioner's proposed rate design is ~~a~~ unreasonable and unjust. The fixed charge proposal is inconsistent with sound cost allocation and rate design principles, and would not produce just and reasonable rates. Petitioner is an outlier to propose 100% of its distribution costs allocated to residential customers through a fixed charge. We will not agree to harm Petitioner's customers by making it the #1 highest residential fixed charge in Indiana and the #10 highest total residential fixed charge out of 171 U.S. investor-owned electric utilities. Petitioner's proposal is unsupported by NARUC Electric Utility Cost Allocation Manual findings and does not follow NARUC's recommendations for studies. It would create a very large residential fixed charge that recovers costs that many public utility regulators have found to be inappropriate for inclusion in fixed charge cost recovery. Finally, Petitioner's proposal unfairly targets residential and small commercial customers, whereas Petitioner is proposing to collect the same costs from medium and large commercial and industrial customers via a per-kW or per-kVa charge rather than a fixed charge. We reject this proposal to collect TDSIC costs through a fixed customer charge. We hereby order that any cost recovery for the TDISC Plan should occur through variable per-kWh charges for residential and small commercial customers.

~~continuation of the rate design currently employed with respect to Petitioner's current TDSIC. Given that Petitioner must file a general rate case before the end of the year, we find that is the more appropriate proceeding in which to propose a change in rate design for the TDSIC rider. Until a change, if any, is made as a result of the Commission's order in Petitioner's next general rate case, we find CEI South should continue collecting TDSIC charges in the same manner as they are currently applied.~~

iii. *Projected Customer Impacts*.

Petitioner's witness Rice presented the projected impact on retail rates and charges of the proposed TDSIC Plan. Attachment MAR-4 summarizes the estimated year-over-year impact that the costs associated with the 2024 – 2028 TDSIC Plan will have on customer rates, by rate schedule, over the life of the TDSIC Plan. In order to align the customer impacts to the TDSIC Plan investments, Mr. Rice stated these impacts exclude the EADIT Credits to be reflected in future TDSIC rates and charges. Pet. Ex. 7 at 15. Given our findings above with regard to the rate design proposal for residential and small commercial customers, we find that Petitioner should submit updated analyses on this point consistent with recovery for residential and small commercial customers through variable per-kWh charges, rather than a fixed customer charge component. ~~Based on our review of the evidence and given that no specific factors are proposed in this proceeding, we find that Petitioner provided sufficient information regarding the projected effects of the TDSIC Plan on retail rates and charges as required by Ind. Code § 8-1-39-9(a)(3).~~

*iv. Determination of Pretax Return***.**

Petitioner proposed to use its WACC based upon the actual capital structure at the end of each respective measurement period in the TDSIC, inclusive of the typical items included in the Company's base rate case capital structure: (1) long-term debt, (2) common equity, (3) customer deposits, (4) cost-free capital, including deferred income taxes, and (5) investment tax credits. Pet. Ex. 6 at 6. The WACC would apply both to TDSIC projects that have been placed in service and also CWIP. Pet. Ex. 6 at 5 and Attachment CMB-1, Sch. 1, line 4 and Sch. 4, line 17. The OUCC asked that this Order clarify that CEI South is to update cost recovery under its TDSIC Plan for base rate case elements such as return on equity and revenue allocation following the issuance of an order in Petitioner's upcoming general rate case, to which Petitioner agreed. Pet. Ex. 7-R at 2. As noted in our discussion of the timing of this TDSIC Plan filing, we do not adopt the OUCC's view that CEI South should delay its TDSIC Plan filing until after base rates are established in that case and we instead find that CEI South can accomplish the update for base rate case elements via a compliance filing as Mr. Rice outlined in his rebuttal testimony.

The parties did not oppose Petitioner's proposed cost of capital calculation to be used for the TDSIC, including agreement on the use of the cost of equity from the last base rate case to calculate TDSIC costs until such time as the update we discussed above is warranted. We find Petitioner's proposed cost of capital calculation is reasonable and should be approved. Per Ind. Code §8-1-39-13(b), CEI South's authorized return for purposes of Ind. Code §8-1-2-42(d)(3) will be adjusted to reflect the incremental return from each approved TDSIC filing.

J. Accounting and Ratemaking Authority.

i. Undisputed Accounting and Ratemaking Treatment.

The TDSIC Statute authorizes recovery of TDSIC costs incurred while the improvements are under construction and post in service. Ind. Code §8-1-39-7. Petitioner seeks to recover financing costs incurred during construction attributable to the capital investments in the Plan. Once and to the extent CWIP ratemaking treatment begins, AFUDC will cease. Otherwise, AFUDC will cease the month after the investment becomes used and useful. Petitioner also proposes to accrue PISCC on all eligible new capital investment from the date the investment is placed in service until the date the investment is included in rate recovery. PISCC would accrue at the WACC. Petitioner also seeks to defer depreciation on used and useful investment during this same period. PISCC and deferred depreciation would be recorded as a regulatory asset. The regulatory assets would be included in rate base and amortized for recovery over the life of the underlying assets. Pet. Ex. 6 at 6, 9-10. This proposed deferral was not opposed and we find it should be approved. Finally, we approve Petitioner's request to defer its plan development costs as described by Witness Behme and to recover such costs through the TDSIC over a period of 5 years.

As noted previously, the TDSIC Statute allows for recovery through the rider of 80% of the TDSIC costs. Petitioner proposes to defer for subsequent recovery as part of its next two general base rate cases 20% of the approved capital expenditures and TDSIC costs for the TDSIC Plan, including costs associated with (a) Capital investment in eligible projects, both completed and under construction, (b) Financing costs on projects under construction (i.e., AFUDC), (c)

PISCC, (d) Projected and annualized property tax and depreciation expense, (e) Amortization of deferred depreciation expense, planning development expense, and PISCC. Pet. Ex. 6 at 4-5. PISCC on the 20% deferred would not accrue. *Id.* at 10. As discussed below, we find Petitioner's proposal with respect to the 20% of TDSIC costs should also be approved. We also find that Petitioner's proposed prioritization of the 80% recovery through the rider in terms of accounting, as described by Witness Behme in direct and not opposed by the OUCC or CAC, should be approved. As Ms. Behme explained, this prioritization is needed to assure Petitioner receives the return granted by Ind. Code §8-1-39-9(c) in accordance with FASB ASC Topic 980 and is consistent with the recovery prioritization approved in Cause No. 44910. *See also Indiana-American Water Co.,* Cause No. 45609 (IURC 3/16/2022), p. 8, 2022 WL 824074, *7.

ii. *Cost of Removal*.

There is a dispute over whether cost of removal associated with retirements should be reflected in TDSIC costs. OUCC witness Lantrip recommended CEI South continue the depreciation expense accounting treatment that was settled upon in the Company's prior electric TDSIC plan approval proceeding (Cause No. 44910), thereby excluding the cost of removal in the accumulated depreciation balance.

The accounting treatment sought by the OUCC here was reached in settlement in Cause No. 44910. Accordingly, we are not bound to continue it under the current TDSIC. We note that CEI South initially requested to include cost of removal in the accumulated depreciation balance in that case as well. Pet. Ex. 6-R at 2. Petitioner's witness Behme described the accounting for asset retirement, which clearly results in the cost of removing retired assets having an effect on net original cost rate base. *Id.*

We find these costs are appropriate to include in the calculation because they are necessary actual costs the Company must incur in order to complete the installation of the TDSIC projects that will replace the assets being retired. Pet. Ex. 6-R at 2. As explained in Petitioner's Response to our docket entry question in this regard, "In order to place the TDSIC improvement in service, it is necessary that plant which is replaced be removed from service. As such, cost of removal of retirements is a cost incurred with respect to the TDSIC improvements." Pet. Ex. 9 at 2. Pursuant to the FERC Uniform System of Accounts, "[t]he cost of removal and the salvage value shall be charged or credited, as appropriate, to such depreciation account [accumulated provision for depreciation applicable to such property]." 170 IAC 4-2-1.1(a) ("The rules and regulations governing the classification of accounts for all major private electric utilities operating within the state of Indiana, as approved, prescribed, and promulgated by the Federal Energy Regulatory Commission on February 12, 1985, are adopted by reference."); 18 CFR Part 101, ¶15,060, Electric Plant Instruction 10(B)(2) (in effect on 2/12/1985). This entry has the effect of increasing net original cost rate base, the cost is incurred in connection with replacing the retired unit with the new asset, and the cost of removal is therefore a capital cost in connection with the eligible transmission, distribution, and storage system improvement. The accounting treatment sought by CEI South allows it to more accurately reflect and request recovery of the cost incurred for the TDSIC Plan's new capital investments. CEI South includes cost of removal within the accumulated depreciation balance in its most recent gas TDSIC Plan, approved in Cause No. 45612. *See* Pet. Ex. 6-R at 2 (citing *S. Ind. Gas & Elec. Co.*, Cause No. 45612 (IURC Apr. 20, 2022)).

We find the cost of removal incurred by CEI South is a cost that pertains to the TDSIC Plan and should be included for timely recovery with all other TDSIC costs.

iii. 20% Deferral.

There also is a dispute as to when the 20% deferral should be recovered. Indiana Code § 8-1-39-9(c) provides that a "public utility that recovers capital expenditures and TDSIC costs under subsection (a) shall defer the remaining twenty percent (20%) of approved capital expenditures and TDSIC costs, including, depreciation, allowance for funds used during construction, and post in service carrying costs, and shall recover those capital expenditures and TDSIC costs as part of the next general rate case that the public utility files with the commission."

In the context of the unique timing of CEI South's TDSIC Plan filing in advance of a general rate case filing later this year, a dispute arose in this case as to the meaning of the language of Ind. Code § 8-1-39-9(b). Petitioner has interpreted this section of the statute to mean the recovery of the deferral will occur in the next general rate case final order following the placement in service of the TDSIC improvements. Tr. at 26. The OUCC takes the position that because CEI South's TDSIC Plan will not commence until January 1, 2024 and it will be filing its next general rate case petition before that date, recovery of the 20% deferral is not available until the subsequent general rate case petition.

We find the OUCC's interpretation of this language without merit. At the hearing, the OUCC pressed Mr. Rice on cross-examination as to whether this portion of the statute refers specifically to the final order in the general rate case. Tr. at 26-27. Mr. Rice expressed his belief that the statute refers to the final order. *Id.* The OUCC appears to tie its interpretation to the verb "files" as suggesting that it is the date of the *petition* that dictates application of this section. The problem is that no utility could ever "recover" its 20% deferral through rates until authorized to do so by this Commission in a final order. It is not the filing of a petition that triggers the recovery of the 20% deferral, but rather the Commission's order acting on that petition.

Based on the evidence presented, we find that 20% of the TDSIC costs shall be deferred in accordance with Ind. Code § 8-1-39-9(c) consistent with the methodology described in Petitioner's witness Behme's testimony.

K. Average Aggregate Increase in Total Retail Revenues Resulting from TDSIC. Petitioner's witness Behme sponsored Attachment CMB-2, which showed that CEI South does not expect that the TDSIC Plan would produce a TDSIC in any year of the Plan that would result in an average aggregate increase in CEI South's total retail revenues of more than 2% in a twelve-month period. Pet. Ex. 6 at 17 and Attachment CMB-2.

Ind. Code § 8-1-39-14(a) requires the Commission to find that an approved TDSIC will not "result in an average aggregate increase in a public utility's total retail revenues of more than two percent (2%) in a twelve (12) month period." The Commission has previously found this determination requires comparing the increase in TDSIC revenue in a given year with the total retail revenues for the past 12 months. *See Northern Indiana Public Service Company, Inc.*, Cause No. 44371, p. 20 (IURC February 17, 2014).

We find the Petitioner's proposal ensures the TDSIC being approved herein will not result in an average aggregate increase in total retail revenues of more than 2% in a twelvemonth period and is consistent with Ind. Code § 8-1-39-14(a).

L. TDSIC Timing under Ind. Code § 8-1-39-9(d).

Ind. Code § 8-1-39-9(d) states that "[e]xcept as provided in section 15 of this chapter, a public utility may not file a petition under subsection (a) within nine (9) months after the date on which the commission issues an order changing the public utility's basic rates and charges with respect to the same type of utility service." Petitioner's last general rate case order was issued in April 2011 in Cause No. 43839. Mr. Rice testified CEI South expects to file its first tracker proceeding to set new rates and charges in August 2024. Pet. Ex. 7-R at 6. Accordingly, we find the first tracker case will be filed more than nine months after Petitioner's last general rate case order was issued in accordance with Ind. Code § 8-1-39-9. Petitioner has also indicated it intends to forego the tracker filing that would naturally follow in February 2025, which would be within nine (9) months of the anticipated date of an order in the general rate case Petitioner must file before December 31, 2023. Pub. Ex. CX-1.

Ind. Code § 8-1-39-9(e) also provides that, "[a] public utility that implements a TDSIC under this chapter shall, before the expiration of the public utility's approved TDSIC plan, petition the commission for review and approval of the public utility's basic rates and charges with respect to the same type of utility service." With respect to its 44910 TDSIC Plan, the record reflects CEI South will be filing a general rate case petition prior to December 31, 2023. Moving forward, CEI South shall file a petition with the Commission for review and approval of its basic gas rates and charges before the expiration of Petitioner's TDSIC Plan in this Cause pursuant to Ind. Code § 8-1-39-9(e).

Ind. Code § 8-1-39-9(f) states that "[a] public utility may file a petition under this section not more than one (l) time every six (6) months." Petitioner's witness Rice testified that Petitioner plans to maintain the existing TDSIC filing schedule currently in place with its 44910 TDSIC Plan. He said there are two periods: May through October and November through April. The approved recoveries for the TDSIC reconciliation period will represent the TDSIC approved amounts for either May through October or November through April and will be noted in Attachment MAR-1, Schedule 4. Pet. Ex. 7 at 7.

We find that Petitioner's proposed timeline for its TDSIC filings is consistent with Ind. Code § 8-1-39-9(f) and is reasonable and should be approved. CEI South's semi-annual filings following the issuance of this Order shall be filed under Cause No. 45894 TDSIC X.

The Company proposes to include the over- or under-recovery variances resulting from TDSIC rates in place from the 44910 TDSIC-13 and 44910 TDSIC-14 periods in the first semi-annual filing in this Cause. Pet. Ex. 7 at 7. No party opposed this proposal and we find it to be reasonable and hereby approve it.

M. Confidentiality. CEI South filed Motions for Protection and Nondisclosure of Confidential and Proprietary Information on May 24, 2023 and August 29, 2023, which were supported by affidavits showing that certain information to be submitted to the Commission was trade secrets under Ind. Code § 24-2-3-2. The Presiding Officers issued Docket Entries on June 6, 2023 and September 1, 2023, finding such information to be preliminarily confidential, after which such information was submitted under seal. After reviewing the information, we find this information qualifies as confidential trade secret information pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2. This information shall be held as confidential and protected from public access and disclosure by the Commission and is exempted from the public access requirements contained in Ind. Code §§ 8-1-2-29 and 5-14-3-4.

N. **Ultimate Conclusion**. Based on the evidence presented in this proceeding, and as discussed herein, we find that Petitioner has presented a plan that CEI South's TDSIC Plan meets the requirements of Ind. Code ch. 8-1-39 and should be approved.

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

1. CEI South's 2024 – 2028 TDSIC Plan is reasonable and should be approved.

2. The projects identified in CEI South's 2024 – 2028 TDSIC Plan constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2.

3. Petitioner's proposed method of calculating a pretax return under Ind. Code § 8-1-39-13 is hereby approved.

4. Petitioner is authorized to defer post in service TDSIC Plan costs, including carrying costs based on the WACC approved herein, on an interim basis until such costs are recovered for ratemaking purposes through Petitioner's TDSIC mechanism or otherwise included for recovery in its base rates through its next general rate case. The regulatory asset resulting from this accrual shall be included in Petitioner's rate base for ratemaking purposes and amortized over the life of the underlying assets.

5. Petitioner is authorized to defer depreciation expense on TDSIC Plan investments on an interim basis until such costs are recovered for ratemaking purposes through Petitioner's TDSIC mechanism or otherwise included for recovery in base rates through its next general rate case. The regulatory asset resulting from this deferral shall be included in Petitioner's rate base for ratemaking purposes and amortized over the life of the underlying assets.

6. Petitioner shall amortize and recover its TDSIC plan development costs over a period of 5 years.

7. Petitioner is authorized to allocate the costs associated with its TDSIC Plan in accordance with our findings set forth herein.

8. Petitioner shall be and hereby is ~~authorized~~ denied authorization to continue assessing the TDSIC as a fixed monthly charge to residential customers; instead, Petitioner shall collect costs through variable per-kWh charges.

9. Petitioner is authorized to defer 20% of eligible and approved capital expenditures and TDSIC Plan costs under Ind. Code § 8-1-39-9(b). Petitioner is also authorized to recover the deferred capital expenditures and TDSIC costs as part of Petitioner's next two general rate cases.

10. Petitioner's proposed process for updating the TDSIC Plan in future TDSIC semiannual adjustment proceedings under the Cause No. 45894 TDSIC X is approved as set forth herein.

11. Per Ind. Code §8-1-39-13(b), Petitioner's authorized return for purposes of Ind. Code §8-1-2-42(d)(3) shall be adjusted to reflect incremental earnings from each approved TDSIC.

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

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:
APPROVED:

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

____

Dana Kosco
Secretary of the Commission

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