STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, LLC FOR; (1) APPROVAL OF PETITIONER'S 6-YEAR PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10; (2) APPROVAL OF A TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT AND DEFERRALS, PURSUANT TO IND. CODE §§ 8-1-2-10, 8-1-2-12, 8-1-2-14, AND 8-1-39-1 *ET SEQ*; AND (3) APPROVAL OF A TARGETED ECONOMIC DEVELOPMENT PROJECT AND RECOVERY OF COSTS ASSOCIATED WITH THE PROJECT, PURSUANT TO IND. CODE §§ 8-1-39-10 AND 8-1-39-11	)	**CAUSE NO. 45647**

INDIANA OEFICE OF UTILITY CONSUMER COUNSELLOR'S EXCEPTIONS TO DUKE ENERGY INDIANA'S PROPOSED ORDER

The Indiana Office of Utility Consumer Counselor ("OUCC"), by counsel, submits its exceptions to Duke Energy Indiana's ("DEI") proposed order. The OUCC provides both revisions in redline form to DEI's Proposed Order in Exhibit A, as well as a clean version. A Word version of both will be provided to the Administrative Law Judge and counsel of record.

The OUCC is also submitting a joint supporting brief as a separate document. To the extent that this submission does not expressly address any additional issues raised in this proceeding, the absence of discussion should not be construed as an endorsement of or acquiescence in the position taken by any other party.

Respectfully submitted,

For
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Deputy Consumer Counselor
Attorney No. 29653-49

CERTIFICATE OF SERVICE

This is to certify that a copy of ***OUCC's Exceptions to Duke Energy Indiana's Proposed Order*** has been served upon the following parties of record in the captioned proceeding by electronic serve on April 6, 2022.

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ORDER OF THE COMMISSION

Presiding Officers:
David L. Ober, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

On November 23, 2021, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company" or "Petitioner") filed a Verified Petition requesting approval of its six-year plan for eligible transmission, distribution, and storage system improvements, pursuant to Ind. Code § 8-1-39-10, including specific targeted economic development ("TED") projects pursuant to Ind. Code §§ 8-1-39-10 and 8-1-39-11 ("TDSIC 2.0 Plan" or "TDSIC 2.0"), and for transmission and distribution infrastructure improvement cost rate adjustment and deferrals pursuant to Ind. Code § 8-1-39-9. Also on November 23, 2021, Duke Energy Indiana prefiled Petitioner's case-in-chief, which included the direct testimony and exhibits of the following witnesses:

- Stan C. Pinegar, President, Duke Energy Indiana;
- Jeremy K. Lewis, Director of Customer Delivery Project Management at Duke Energy Business Services, LLC ("DEBS");
- Martin D. Dickey, Vice President, Transmission Construction & Maintenance at DEBS;
- James W. Shields, Principal Consultant at Black & Veatch Management Consulting LLC ("B&V");
- Erin Schneider, Director of Economic Development at Duke Energy Indiana; and
- Maria T. Diaz, Director, Rates and Regulatory Planning at Duke Energy Indiana.

Petitioner filed a motion for protection of confidential and proprietary information that was preliminarily granted on December 1, 2021. Petitioner filed revised testimony of Mr. Lewis on December 14, 2021.

Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), Duke Industrial Group ("Industrial Group"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy"), Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance ("Wabash Valley"), and Steel Dynamics, Inc. ("SDI") each filed petitions to intervene, all of which were subsequently granted.

On December 2, 2021, the Commission issued a Docket Entry creating a subdocket (Cause No. 45647 S1) for the purpose of reviewing the proposed TED project and establishing its procedural schedule.

On February 18, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony of Dr. Casey A. Shull, Senior Utility Analyst in the OUCC's Electric Division, and Kaleb G. Lantrip, Utility Analyst in the OUCC's Electric Division. Hoosier Energy prefiled the direct testimony of Matt Mabrey, Vice President of Operations.

On February 25, 2022, Petitioner filed a second motion for protection of confidential and proprietary information that was preliminarily granted on March 4, 2022.

On March 4, 2022, Duke Energy Indiana filed the rebuttal testimony of Jeremy K. Lewis, Martin D. Dickey, and Maria T. Diaz.

An evidentiary hearing was held in this Cause commencing at 9:30 a.m. on March 24, 2022, in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of Duke Energy Indiana, the OUCC, and Hoosier Energy were admitted into the record without objection.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. <u>Notice and Jurisdiction</u>. Notice of the hearing in this Cause was given and published as required by law. Duke Energy Indiana is a public utility as defined in Ind. Code §§ 8-1-2-1(a) and 8-1-39-4. Under Ind. Code ch. 8-1-39, the Commission has jurisdiction over a public utility's plan for eligible transmission, distribution, and storage system improvement charges ("TDSIC"), including TED projects. The Commission, therefore, has jurisdiction over Petitioner and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics</u>. Duke Energy Indiana is a public utility and wholly-owned subsidiary of Duke Energy Indiana Holdco, LLC, with its principal office located in Plainfield, Indiana. Petitioner is engaged in the business of rendering retail electric utility service and owns, operates, manages, and controls, among other things, plant, property, and equipment within Indiana used for the production, transmission, distribution, and furnishing of such service. Duke Energy Indiana provides electric service to approximately 860,000 customers in 69 Indiana counties. Petitioner also sells electric energy for resale to municipal utilities, Wabash Valley Power, Indiana Municipal Power Agency, and other electric utilities.

3. Relief Requested in this Cause. In accordance with Ind. Code § 8-1-39-10, Petitioner requests approval in this Cause of its TDSIC 2.0 Plan, as follows:

(a) a finding that the projects contained in the TDSIC 2.0 Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2;

(b) a finding that Petitioner included the best estimate of the cost of the eligible improvements included in the TDSIC 2.0 Plan;

(c) a determination that the public convenience and necessity require or will require the eligible improvements included in TDSIC 2.0;

(d) a determination that the estimated costs of the eligible improvements included in TDSIC 2.0 are justified by incremental benefits attributable to the TDSIC 2.0 Plan;

(e) a determination that the TDSIC 2.0 Plan is reasonable and should be approved, and designating the eligible transmission, distribution and storage system improvements included in TDSIC 2.0 as eligible for transmission, distribution and storage system improvement charge treatment in accordance with Ind. Code § 8-1-39-9;

(f) authority to recovery 80% of the TDSIC 2.0 costs via Standard Contract Rider No. 65 ("TDSIC Rider"), and deferral with carrying costs of 20% of the TDSIC 2.0 costs for subsequent recovery in Petitioner's next general retail electric base rate case; and

(g) approval of Petitioner's proposed process for updating the TDSIC 2.0 Plan in future annual proceedings.

4. Duke Energy Indiana's Case-In-Chief.

A. Mr. Pinegar. Mr. Pinegar testified that although Petitioner's initial TDSIC plan targeted the replacement of aging infrastructure on the system, the priority of TDSIC 2.0 is to provide reliability benefits to customers, such as reduction of frequency and duration of interruptions, hardening and resiliency of the grid, and modernizing the grid to manage growing renewable, distributed generation on the system. He testified that Petitioner's commitment to customer value is evident in the rigorous cost to benefit analysis utilized to ensure selection of projects that provide optimal value for customers to improve the reliability, flexibility, and capacity of the grid to meet growing customer expectations, demands, and needs. Mr. Pinegar described today's customer expectations, stating that power quality and reliability are the top drivers, followed closely by price. He testified that, although Petitioner appreciates the investments provided in TDSIC 2.0 need to be undertaken, Petitioner is limiting the overall average annual rate impact to approximately 1%.

Mr. Pinegar testified that TDSIC 2.0 addresses the changing service expectations of Petitioner's commercial and industrial customers. In addition to reliable service, the proposed TDSIC 2.0 investments help facilitate the expansion of renewable and distributed generation for all customers. The TDSIC 2.0 Plan includes technology that improves reliability, increases power quality, and minimizes momentary outages. He testified that the various TED projects that may be executed during TDSIC 2.0 will provide adequate capacity and reliable service to attract companies looking to locate and expand in our state.

Mr. Pinegar testified that the objectives of the proposed TDSIC 2.0 Plan are to improve reliability for Indiana customers, advance grid hardening and resiliency, enable expansion of renewable and distributed generation, and facilitate economic development growth. With much of Duke Energy Indiana's system over 40 years old and the expansion of Distributed Energy Resources ("DER") and electrification trends, TDSIC 2.0 will ensure reliability and prepare the grid for the future. Measured investments will avoid future customer interruptions ("CI") and customer minutes interrupted ("CMI"). Mr. Pinegar testified Petitioner expects to show measurable improvement to reliability over the six-year period by measuring CI and CMI avoided, which after the successful implementation of TDSIC 2.0, will produce a minimum 19% improvement to System Average Interruption Duration Index ("SAIDI") and a minimum 17% improvement to System Average Interruption Frequency Index ("SAIFI"). To improve reliability, TDSIC 2.0 includes investments to advance hardening and resiliency of the transmission and distribution grid. He explained that hardening physically changes the infrastructure to make it less susceptible to damage, while resiliency makes the grid smarter and better able to recover from events more quickly. Proposed TDSIC 2.0 hardening programs include line rebuilds, pole upgrades and replacements, installation of intermediate dead-end structures, targeted underground, transformer replacements, and uprating 4kV lines to 12kV. Proposed TDSIC 2.0 resiliency programs include Self Optimizing Grid and Automated Lateral Device investments, and installation of Supervisory Control and Data Acquisition ("SCADA") to transmission switches and substations.

Mr. Pinegar testified that TDSIC 2.0 will facilitate increased distributed and renewable energy investments in the State by advancing a two-way smart-thinking grid networked to intelligently detect, rapidly react, and proactively adapt to changes in usage. It also enables customers to become active participants in the grid system by installing assets like rooftop solar and premise level storage.

Mr. Pinegar testified that Petitioner worked with the Indiana University Business Research Center ("IBRC') to perform an Economic Impact Study on the transmission and distribution projects within TDSIC 2.0, excluding the targeted economic impact projects. TDSIC 2.0 will bring economic benefit to Indiana by creating or supporting an estimated 1,270 jobs each year of the six-year TDSIC 2.0 Plan, with an expected average pay-range of $135,000. The TDSIC 2.0 investments will also produce an estimated $4.3 million in additional state and local tax revenue and $215 million in gross domestic product annually over the six-year period. Mr. Pinegar testified the TDSIC 2.0 Plan is reasonable and in the public interest.

B. <u>Mr. Lewis</u>. Mr. Lewis testified that TDSIC 2.0 is a six-year, $2.0 billion plan including an estimated $158 million of TED investments. Capital transmission investments total approximately $815 million, while distribution investments total $1 billion over the six years. TDSIC 2.0 is designed to achieve cost-effective improvements in grid reliability, safety, grid modernization, and economic development. He testified greater than 80% of the proposed TDSIC 2.0 programs will influence reliability through proactively reducing the frequency and duration of outages. Looking retroactively at Duke Energy Indiana's past five-year average, if the proposed TDSIC 2.0 investments were in place, he estimated approximately 23% of CI and 28% of CMI would have been avoided. He testified that TDSIC 2.0 programs will transform the system to a dynamic smart-thinking and self-healing grid that will quickly locate faults, reroute power around faults, and restore power more quickly to customers, thus avoiding CI and CMI both on Major Event Days ("MED") and non-MED. Variables outside of TDSIC projects, such as major storms, vegetation management, cellular advancement, and vehicle accidents, impact reliability measurements and project performance metrics, so it is important to measure the success of TDSIC 2.0 following the full execution of the investment plan.

Mr. Lewis testified that grid hardening physically improves the durability and stability of the energy infrastructure making the asset or grid stronger, while resiliency makes the grid smarter and better able to react to events. Although resiliency measures do not prevent damage, they enable grid systems to continue operating despite damage and/or promote a more rapid return to normal operations when damages or outages do occur. Mr. Lewis testified that 24 of the 35 sub-programs in TDSIC 2.0 contribute to resiliency and hardening of the grid. These sub-programs will help eliminate outdated grid architectures, target vulnerable assets with high consequence of failure, solve asset conditions that contribute to extending outages, and maintain or improve customer safety. Inspection-based programs will proactively replace grid hardware and equipment based on age, condition, and historical failure rates. TDSIC 2.0 is also designed to facilitate the expansion of renewables and distributed generation through building a self-optimizing grid, Integrated Volt-Var Control ("IVVC"), SCADA communication, substation relay replacements, circuit visibility and control, and circuit rebuilds.

Mr. Lewis testified that TDSIC 2.0 utilizes a targeted set of programs that advance the distribution system allowing the grid to adjust the power flow to self-heal when an event occurs, thus avoiding CI and CMI. These programs include Self Optimizing Grid ("SOG"), which will isolate faults on the backbones of circuits from approximately 1,000 customers per segment to 400 customers per segment, allowing service to be restored to other portions of the circuit; Targeted Underground ("TUG"), which places strategic infrastructure underground to eliminate the source of overhead outages; and Automated Lateral Device ("ALD"), which is targeted to the lateral lines of distribution systems to reclose on temporary faults and isolate those temporary faults to eliminate customer outages. These programs will improve the experience of Duke Energy Indiana's commercial and industrial customers with enhanced troubleshooting efficiencies to improve restoration times, fewer interruptions, and reduced outage durations. After the completion of TDSIC 2.0, the Company estimates the number of customers served by automated circuits to increase from 11% to over 65%. Mr. Lewis testified that TDSIC 2.0 also includes additional installation of technology with near real-time two-way data communication, data collection, and remote operations capability to pinpoint and isolate system trouble to restore service more quickly.

Mr. Lewis provided a TDSIC 2.0 Workplan summarizing the distribution projects, as well as cost details. He testified that the projects were selected based on a variety of engineering analyses and asset data aligning with the TDSIC 2.0 objectives and focused on their improvement to system integrity, reliability, and benefit to customers. A Class 5 estimate was assigned to each potential project and the initial list of investments was provided to Black & Veatch ("B&V") to run through the Investment Plan Analysis and scored through a cost to benefit ratio by substation. He testified that the investment plan in TDSIC 2.0 will be executed by substation and circuit to gain labor resource efficiencies. He testified that the Investment Plan Analysis is the accumulation of all Duke Energy, B&V, Copperleaf, value models, risk models, and optimization efforts together. Projects were identified by Duke Energy Indiana to address known conditions and performance issues on the system, which were then evaluated for consequence and likelihood of failure. Opportunities to improve these conditions and enhance functionality through proven automated technologies were also assimilated to put through the Investment Plan Analysis. He testified that leveraging system knowledge with the rigorous risk and value studies led to the selection of projects that provide the most benefit for the cost. In selecting the TDSIC 2.0 investments, approximately $1.7 billion of potential distribution investments were analyzed through the Investment Plan Analysis, which returned $775 million of select distribution investments. The Investment Plan Analysis used two funding mechanisms: "optimized" and a small amount of "reserved," which meant the subject matter experts held a portion of the funding specifically for these necessary sub-projects within Inspection Based, 4kV Conversion, Underground Cable Rehab, and Capacitor Automation. Funding levels for these projects were selected using historical analysis of performance, value, and necessity to the TDSIC objectives. All other projects were optimized in the model.

Mr. Lewis described the five distribution program categories within TDSIC 2.0 as follows:

(1) Circuit Backbone Uplift. Includes 8 sub-programs which target circuit enhancements to support circuit modernization, including automation, segmentation, and controlling circuit operations to enable self-optimization. These investments reduce outage impacts with respect to their occurrence frequency, grid impact footprint, recovery time, and cost, with the added value of improving capability to better integrate distributed energy resources on the grid.
(2) Overhead Lateral Uplift. Includes 4 sub-programs aimed at improving the lateral grid's reliability and resiliency. These projects add segmentation and automation of the circuit laterals to reduce the number of outages and customer impacted as well as reducing the duration of the outages.
(3) Underground System Uplift. Targets cable rehabilitation for improved reliability.
(4) 4kV Conversions. Consists of the conversion of risk-prone, legacy standard, and dated architecture of lower operating voltage lines to a 12kV system to address all three objectives of the Investment Plan.

(5) Inspection Based Programs. Includes 4 sub-programs and is a condition-based program geared towards proactively replacing grid hardware and equipment based on effective age and historical failure rates.

He provided an overview of the TDSIC 2.0 sub-programs, which are detailed in Petitioner's Exhibit 4-A (JWS), including those contributing to the enablement of expanding solar and renewables. Collectively, TDSIC 2.0 distribution capital investments leverage grid automation, data management and automated grid sensors, and communication and response capability to effectively integrate a greater proportion of renewable and distributed energy resources across the distribution network, while improving reliability, economic performance and customer choice. He testified that the TDSIC 2.0 distribution programs improve grid hardening, resiliency, and reliability throughout Duke Energy Indiana's service territory, benefiting all customers.

Mr. Lewis provided a detailed cost estimate for every project in the TDSIC 2.0 Investment Plan derived utilizing either engineered work, built up estimates, or parametric modeling, using the Association for the Advancement of Cost Engineering International ("AACE") standards and Duke Energy's Project Management Center of Excellence guidelines. Each TDSIC 2.0 project was estimated based on asset or compatible unit using historical values, subject matter expertise and reviewed by B&V. He testified that the majority of projects in years one and two achieved Class 2 status, with outer years at Class 3 or 4. A projected contingency amount of 15% was calculated using a Monte Carlo simulation, and added to the base cost estimate to cover estimate uncertainty and risk over the six-year TDSIC 2.0 Plan. Mr. Lewis testified that any direct project O&M expenses related to distribution capital projects, as well as vegetation removal necessary to perform the capital project construction, are included in the cost estimate. Mr. Lewis testified that B&V was brought in as a third party to evaluate and validate the transmission and distribution project selections, estimates, and economic impact, concluding that the TDSIC 2.0 Plan cost estimating was reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes.

Mr. Lewis testified that the TDSIC 2.0 Plan is expected to provide secondary benefits to the state by generating additional economic activity, which was assessed by the IBRC at Indiana University. The IBRC concluded the TDSIC 2.0 Plan, excluding TED and contingency, will contribute an estimated $1.04 billion in compensation in Indiana and approximately $1.29 billion in gross domestic product.

Mr. Lewis testified that Duke Energy Indiana proposes to update its TDSIC 2.0 Plan annually in the fall, with cost recovery filings in the spring. He explained that units in a project may be susceptible to change, especially in outer years, due to the most current evaluations of system needs. To provide flexibility to TDSIC 2.0 and mitigate the likelihood of change, similar to the TDSIC 1.0 Plan, Duke Energy Indiana requests the Commission designate the identified alternate list of projects as eligible projects so that in future TDSIC 2.0 rider filings, the Company has the option of moving projects on to and off of the alternate list and active plan as necessary for the greatest benefit to the system and its customers. He testified that the overall costs of TDSIC 2.0 would not be substantially changed by substituting these alternate plans. If the overall investment plan is tracking under its expected cost, it is prudent and beneficial to customers to insert projects off the alternate list into the active TDSIC 2.0 Plan to create additional customer value while staying under the overall cost estimate and within the 1% customer annual rate increase.

Mr. Lewis testified that Duke Energy Indiana is quantifying reliability performance through avoided CI and CMI, estimating an 80% probability of avoiding between 22 and 45 million CMI and between 149,000 and 249,000 CI upon the conclusion of the TDSIC 2.0 investments. Based on a historical five-year average, this is expected to produce a minimum 19% improvement to SAIDI and 17% improvement to SAIFI. The 80% probability factor is based on variables outside of TDSIC 2.0. He testified regarding Duke Energy Indiana's commitment to tracking CI/CMI of the self-optimizing grid based on its automation savings and contribution to SAIDI/SAIFI and proposed tracking progress by reviewing total savings by annum for minimum and maximum CI/CMI, inclusive of the target, and the impact of MEDs and non-MEDs. To develop the quantitative customer benefits, most recent complete five-year historical reliability data in conjunction with the TDSIC 2.0 program scope was checked against similar work in other jurisdictions. Those effects are then calculated on the expected future reliability performance of the Indiana system. He testified that an additional benefit from the TDSIC 2.0 Plan is the Value of Lost Load calculated by B&V utilizing the Department of Energy Interruption Cost Estimator ("ICE").

Mr. Lewis testified that Duke Energy Indiana has a multitude of annual transmission and distribution projects that are not included in TDSIC 2.0. The approach for identifying assets for replacement in the TDSIC 2.0 Plan is the result of the rigorous Investment Plan Analysis, particularly the new methodology of evaluating projects methodically, with benefit to cost ratio. He testified that there are no duplicative items in the TDSIC 2.0 Plan. Duke Energy Indiana has provided the best estimate of the costs of the eligible improvements within TDSIC 2.0, and public convenience and necessity require each component of TDSIC 2.0. The TDSIC 2.0 Plan is reasonable, necessary, and justified by significant reliability, hardening and resiliency, and modernization benefits.

C. <u>Mr. Dickey</u>. Mr. Dickey described the two main categories of transmission programs in TDSIC 2.0 – Line Hardening and Resiliency, and Substation Hardening and Resiliency, which focus on hardening the grid by preventing events from adversely affecting system operation and enhancing system resiliency through technology designed to isolate faults by automated remote devices that reconfigure the system to reduce and shorten customer outages. He testified that the benefits from the distribution investments are complemented by benefits received from the transmission portion of TDSIC 2.0, with an overall benefit to cost ratio of 3.5 and overall program value of $2.8 billion for the $800 million core transmission project planned investment. This means for every dollar spent on the TDSIC 2.0 Plan, Indiana customers should receive a payback of $3.50 in primary benefits. Implementation of these projects will result in risk reduction, avoided customer outages, avoided loss of system redundancy, and power quality improvements.

Mr. Dickey provided examples of the TDSIC 2.0 sub-programs designed to improve the hardening of the grid, including wood to non-wood structure replacements, wood cross arm replacements, transmission line rebuilds, installation of intermediate dead-end structures to mitigate cascading events, and replacing deteriorated and obsolete equipment prone to catastrophic failures. Examples of TDSIC 2.0 sub-programs designed to improve resiliency of the grid include looping short radials through existing substations, adding Supervisory Control and Data Acquisition ("SCADA") functionality to substations, adding SCADA to switches, and transmission relay upgrades at substations. The SCADA switch sub-program will increase the number of remote-controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults. Mr. Dickey testified that the TDSIC 2.0 upgrades to the 68kV transmission system will increase continuity of service and improve power quality and reliability for many industrial and wholesale customers. The hardening and resiliency of the Bulk Electric System ("BES"), which are assets 100kV and above, is a critical component to reliable service. Although the BES does not directly impact CI/CMI avoided, it is the link between generation facilities to the 69kV system and distribution system that ultimately serves customers' homes and businesses. He testified that while BES is redundant in design, increased age, deterioration, and obsolescence of equipment requires increased investment to avoid disruption to power flows and customer interruptions. Mr. Dickey testified that power quality issues, such as momentary interruptions and voltage sags, can result in loss of revenue and productivity for industrial customers. The Transmission Line and Substation Hardening and Resiliency programs reduce the risk of momentary and sustained outages during an in-service failure that can yield productivity and financial gains for many large industrial customers. He testified that there are TDSIC 2.0 substation projects that support IVVC and increase the ability of the Distribution System Operators to remotely monitor and control the voltage level the substations supply to the distribution circuits. Upgrades to control capability and added voltage regulation equipment are included in TDSIC 2.0.

Mr. Dickey provided cost estimates for each transmission line and substation project in TDSIC 2.0 and explained how the estimates were developed. He testified that using site reviews conducted by Duke Energy and Burns & McDonell (consulting engineer subject matter experts), an asset-specific project scope was developed to calculate AACE Class 4 estimates. The Class 4 estimates were created by using averages of recently bid capital projects, then applying those averages and unit costs to the TDSIC 2.0 project work scopes. He testified that as projects approach their targeted in-service year, typically two years prior to construction, an AACE Class 3 estimate will be prepared. In the case of TDSIC 2.0 transmission, there are no Class 3 estimates utilized. Rather, to provide the best estimate, Class 2 estimates have been prepared for projects up to three years prior to construction and for the first two years of the transmission program (2023 and 2024). Mr. Dickey testified that the cost estimates include project-related O&M incurred during the construction of the capital projects. In addition, contingency is added to the base cost estimates of the project categories to cover estimate uncertainty and risk, per AACE guidelines.

D. <u>Mr. Shields</u>. Mr. Shields testified that B&V was engaged by Duke Energy Indiana to identify transmission and distribution ("T&D") system improvements and asset replacements that produce the greatest benefits to customers. For its investment plan analysis, B&V combined Copperleaf's decision analytics tool for quantifying benefits and optimizing investments with a Risk Adjusted Project Prioritization ("RAPP") modeling tool to identify high risk assets. Although Duke Energy Indiana determined the objectives of the TDSIC Plan, collaboration with B&V identified the programs to support those objectives. Mr. Shields explained how the benefit categories were identified and mapped to a value model within Copperleaf to calculate net benefits for each project. Optimizing investments helped ensure high value projects were located in the areas on the system that produced the greatest value. Constraints were applied at the sub-program level to determine TDSIC 2.0 projects. Mr. Shields described Copperleaf as a decision analytics software tool used to quantify benefits associated with critical infrastructure investments. Value models were developed for each investment type with specific value measures that quantify the benefits of the investments. Once the cost of each investment was paired with the benefits, the Copperleaf tool ran various investment scenarios to produce an optimized investment plan. He testified that the RAPP tool was used to compliment Copperleaf by identifying high risk assets. RAPP calculated risk scores for assets included in the asset risk register, with risk defined as the product of Probability of Failure ("PoF") multiplied by the Consequence of Failure ("CoF"). The actual age of assets was adjusted to an effective age using survivor curves and asset health data, from which a probability failure was then calculated. CoF was calculated from a criterion of consequences and scored based on the criticality of the consequence. The RAPP identified high risk assets that were input into Copperleaf to compete for funding with other projects identified in the development of the TDSIC 2.0 Plan.

Mr. Shields described the value model concept which combines all the benefits a project produces and calculates the value measure (financial and non-financial benefits produced) to quantify the net benefits of the project. The value measures used in development of TDSIC 2.0 were risk mitigation, benefits, and cost. For risk mitigation value measure, used to capture the value of avoiding undesirable outcomes, a uniform risk matrix was developed to align the mitigation of risk to a common scale. Mr. Shields provided the probability levels used in calculating risk mitigation value units, as well as how the thirteen quantifiable benefit categories were mapped to sub-programs that produced the benefit. Value models in Copperleaf combined all the value measures a project could produce to calculate the net value of the project. From this portfolio of investments, an optimization analysis was performed to direct the funding of projects using reserved and optimized funding methods. He testified that the optimization approach used directed funding based on highest benefits generated, to specific areas on the system. Funding levels were set by Duke Energy Indiana and applied in the TDSIC 2.0 Plan development. Mr. Shields testified that in general, the same methodology was used to evaluate both transmission and distribution projects. However, benefits were assessed slightly differently due to transmission systems being designed for redundancy to minimize impacts on large numbers of customers and to transport power long distances reliably. Therefore, benefits on the transmission system were focused less on the value of loss load and more on maintaining and reinforcing the redundancy that currently exists. Distribution substation and line project benefits were valued based on the reduction in future outages compared to historical system performance. Mr. Shields summarized the CMI and CI distribution program improvements as a result of the TDSIC 2.0 Plan. He testified that the TDSIC 2.0 Plan has a 2.8 benefit to cost ratio, showing the estimated cost of the TDSIC 2.0 Plan is justified by the incremental benefits attributable to the TDSIC 2.0 Plan.

Mr. Shields testified that B&V validated Duke Energy Indiana's cost estimates using the AACE classification system and by performing independent estimate reviews for other TDSIC filings in Indiana. The estimate sample included both AACE Class 2 and Class 4 type estimates used in the TDSIC 2.0 Plan. The estimates were reviewed with line item material and labor estimates including quantities needed for the specific projects. He testified that Duke Energy Indiana's assumptions and methodology used to develop the estimates were reasonable.

E. **Ms. Schneider**. Ms. Schneider testified regarding Duke Energy Indiana's request for approval of the River Ridge Project as a TED project for inclusion and associated cost recovery in TDSIC 2.0. Ms. Schneider testified that Duke Energy Indiana is working with more than ten industrial and commercial customers seeking sites for new facilities at River Ridge Commerce Center, a business and manufacturing park with over 6,000 prime acres of land under development. Petitioner currently has insufficient capacity to support the estimated 500+ MW load for these project commitments. Petitioner's River Ridge Project proposes to invest additional infrastructure at the site to increase capacity on Duke Energy Indiana's system and continue business investment at River Ridge.

Ms. Schneider testified that current projections estimate the River Ridge Project could create more than 8,000 jobs and bring about $3 billion in capital investment. The associated wages from those jobs will positively impact the region, and the capital investment will increase the tax base and overall economy within the region and State of Indiana. She testified that any potential investment at River Ridge would likely come in under Petitioner's existing economic development tariff (Rider 58) or a special contract with similar conditions. Ms. Schneider explained that proactively building the transmission infrastructure to increase capacity at River Ridge will attract more economic development and capital investment to the area, which aligns with the Indiana Economic Development Commission's (IEDC) mission to attract and support new business investment, create new jobs for Hoosiers, and further Indiana's legacy as one of the top states in the nation for business. It also allows Duke Energy Indiana to work with community partners, such as One Southern Indiana to achieve their goals to enhance the area's vibrancy by facilitating economic transactions that generate wealth and add to community prosperity as depicted in its letter of support included as Petitioner's Exhibit 5-B.

Ms. Schneider testified that under the River Ridge Project, Petitioner plans to install 138kV 6-position, 4-breaker ring bus, which will allow future isolation of the substation for outage-free maintenance. Petitioner proposes to loop In/Out existing 138kV line 13857, which will increase reliability by adding a substation to shorten a longer circuit into two shorter circuits. She testified that Petitioner will be constructing the "high side" or the transmission side of the substation only, maintaining close proximity to the existing 138kV line. An initial yard will be constructed for the substation sized to accommodate a variety of customer-specific scenarios for the "low side" or distribution side of the substation. Ms. Schneider testified that the estimated cost of the River Ridge Project is $44 million. TED treatment of the River Ridge Project allows Petitioner to make the necessary investments to extend required services of existing customers and provide an additional

200 MW of capacity to serve additional customers. She testified that Petitioner sent a letter to IEDC for approval to treat the costs associated with the proposed River Ridge Project as TDSIC costs, in compliance with GAO 2016-6.

Ms. Schneider described the potential for additional TED projects throughout Petitioner's six-year TDSIC 2.0 Plan period. Updated information regarding the scope, timing and cost of any additional TED projects will be included in Petitioner's semi-annual TDSIC Rider and update filings.

F. **Ms. Diaz**. Ms. Diaz testified that this proceeding was filed more than nine months after Petitioner's last retail electric base rate case order in Cause No. 45253, and the proposed TDSIC 2.0 investments are not included in its rate base. She confirmed Petitioner's intention to file for a change in basic rates and charges before the expiration of TDSIC 2.0. Revised rate schedules resetting the TDSIC Rider charge will be filed once new basic rates and charges that include TDSIC 2.0 investments become effective.

Ms. Diaz testified that Petitioner is requesting authority to recover 80% of the retail jurisdictional share of TDSIC 2.0 costs through the existing Rider 65, pursuant to Indiana Code § 8-1-39-9(a). The statutory recoverable TDSIC costs include depreciation, O&M, property taxes and pretax return on eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post-in-service, as well as costs associated with an approved economic development project. Petitioner requests authority to accrue post-in-service carrying costs until the costs related to TDSIC 2.0 are included in retail rates, with the accrual at rates equal to Petitioner's overall weighted average cost of capital most recently approved by the Commission. She testified that Petitioner will include in TDSIC 2.0 expenditures for projects that are in-service at the time of the annual cut-off dates. She testified that post-in-service carrying costs accrued on TDSIC costs, including both debt and equity financing, will be accrued on approved capital expenditures, including accrual on previously computed post-in-service carrying cost amounts, from the in-service date until such costs are included in rates under Rider 65 or in base rates.

Ms. Diaz testified that Petitioner proposes to defer the remaining 20% of the retail jurisdictional portion TDSIC 2.0 costs until its next general retail electric base rate case. Pursuant to Ind Code 8-1-39-9(c), Petitioner requests approval to defer for subsequent recovery the retail jurisdictional portion of the remaining 20% of approved expenditures, allowance for funds used during construction ("AFUDC"), post-in-service carrying costs, O&M expense, property taxes, and depreciation expense using a regulatory asset account (FERC CFR Account 182.3) until such costs are fully reflected in Duke Energy Indiana's retail base rates after a general retail electric base rate case. Petitioner also requests carrying costs on the deferred costs be accrued using Duke Energy Indiana's overall weighted average cost of capital as most recently approved by the Commission. Ms. Diaz testified that AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates or when the projects are placed in service. She testified that the deferral of TDSIC 2.0 costs will be from the in-service date until the cost is included in Petitioner's rates under Rider 65 or in base rates.

Ms. Diaz testified that Petitioner will consider both the FERC accounting and whether the function is a transmission or distribution service when including investments in the TDSIC Rider and will not limit the included costs to specific FERC accounts. She testified that the rates used for depreciation expense are the weighted average depreciation rates approved in Petitioner's most recent retail base rate case in Cause No. 45253 by the transmission and distribution plant groupings. Petitioner proposes to net depreciation expense on retired plant against depreciation on new plant included in the TDSIC Rider. She testified that Petitioner has estimated and included depreciation expense reductions for retirements in this plan filing so as to not recover new and replacement project depreciation expense on both the additions and the retired asset. Petitioner will present the actual calculations supporting the reductions for the depreciation expense credits in the first tracker filing. Ms. Diaz testified that the proposed deferred accounting treatment is in accordance with U.S. Generally Accepted Accounting Principles (GAAP) and is appropriate from both a ratemaking and an accounting perspective.

Ms. Diaz testified that there are no proposed changes to the existing TDSIC Rider. The TDSIC Rider will recover 80% of the retail jurisdictional portion of the costs associated with TDSIC 2.0 projects, including financing costs, O&M directly associated with the construction of the project, depreciation, property taxes, and other Commission approved costs in the establishment of the revenue requirements. She testified that the components of the revenue requirement, which includes targeted economic development projects for TDSIC 2.0, are multiplied by revenue conversion factors to establish the total revenue requirement for the TDSIC Rider. Petitioner proposes to use the 9.70% current return on common equity approved in Cause No. 45253 in the development of Rider 65 for TDSIC 2.0. The capital structure would be updated with each TDSIC 2.0 filing, along with the debt costs. Ms. Diaz the rate impact estimates for TDSIC 2.0 reflect 100% allocation to retail, with allocation of the transmission and distribution revenue requirement for Rider 65 based on the revenue requirement by rate group approved in Cause No. 45253. Costs will be billed to individual customers within a rate group based on kWh sales, except customer served under Rate HLF which will be recovered based on non-coincident kW demands. Ms. Diaz testified that the fuel clause return test will be adjusted with the incremental net operating income from Rider 65. Ms. Diaz testified that the TDSIC Rider will continue to be implemented using forecasted amounts for O&M, depreciation, and property taxes based on annual cut-off dates. Financing costs on invested capital will be on an actual basis based on annual cut-off dates used for in-service capital projects. In subsequent Rider filings, Petitioner will true-up amounts to actual levels of O&M, depreciation, and property taxes and to actual kWh sales levels.

Ms. Diaz proposed a timeline for the TDSIC 2.0 Rider 65 filings, with the first filing to occur in the April 2024 timeframe with a projected effective date of approximately October 2024. The April filing would seek recovery of capital expenditures and costs as of December 2023 and estimated O&M, property taxes, and depreciation expense for the following 12-month period of October 2024 through September 2025. Going forward, Petitioner would continue to file the TDSIC Rider each April, with a reconciliation included in subsequent Rider 65 filings.

Ms. Diaz testified that Petitioner is proposing to recover its expenses incurred for retaining B&V. Similar to the current TDSIC 1.0 plan, Ms. Diaz proposed to amortize all B&V costs over a three-year period.

Ms. Diaz testified that the total annual average retail rate impact of TDSIC 2.0 compared to prior year retail revenue is estimated to be slightly less than 1% over the recovery periods. She testified Rider 65 filings will include the actual proposed revenue increase compared to the total retail revenues at the time. Should an actual total amount exceed the 2% annual total statutory cap, Petitioner requests approval to defer recovery of the TDSIC costs above the cap, pursuant to Ind. Code 8-1-39-14(b).

5. <u>OUCC's Direct Evidence</u>.

A. Dr. Shull. Dr. Shull testified it is impossible to verify whether B&V's Copperleaf modeling logic is reasonable or accurate because of its proprietary status. B&V relied upon spreadsheet values from Petitioner as inputs into its proprietary modeling algorithms to produce outputs to categorize projects into value measures used to optimize and select projects for inclusion in TDSIC 2.0. Dr. Shull testified he identified a miscalculation in the average number of outages used as an input for Value of Lost Load ("VOLL") provided by Duke Energy Indiana to B&V, and that Petitioner was unable to explain the miscalculation. He testified this fact calls into question the validity of the VOLL values used to produce TDSIC 2.0.

Dr. Shull testified the proposed TDSIC 2.0 Plan includes increasing redundancy through rehabilitation of electrical transmission, substations, and distribution facilities. He defined redundancy as the ability for a system to have alternate methods of delivering a specific service to its customers during adverse conditions. He testified Petitioner failed to provide empirical evidence or support explaining why the public convenience and necessity require the replacement or rehabilitation of these proposed redundancy projects. He testified Petitioner claims its system is already highly redundant and reliable and has provided no support for an added layer of redundancy. Dr. Shull identified nineteen transmission line projects he recommended be removed from TDSIC 2.0, stating the projects do not qualify as system modernization, have not been shown to require replacement due to deterioration, and do not result in a reduction of CI or CMI or improved reliability. Dr. Shull testified the proposed TDSIC 2.0 Plan anticipates a 0.21% decrease in SAIFI. Therefore, the incremental benefit these projects may provide does not justify the $800 million cost and is not for purposes of safety, reliability or modernization.

Dr. Shull testified that adding electrical system devices in TDSIC 2.0 will not necessarily provide the capability and/or market for future Distributed Energy Resources ("DER") installations. He testified Petitioner has not demonstrated a customer demand for DER, and it would be prudent for Duke Energy Indiana to wait and build its system specific to meet its customers' DER needs. Given these projects are unnecessary and outside the scope of the TDSIC statute, they would not meet the obligation of "protecting affordability" as stated in Ind. Code § 8-1-2-0.5.

Dr. Shull testified Petitioner's cost-benefit assessment does not take into consideration the unstable aluminum, copper, and steel commodity prices. Therefore, the TDSIC 2.0 cost estimates are understated, resulting in an overstated incremental benefit calculation.

Dr. Shull recommended Duke Energy Indiana's TDSIC 2.0 Plan be denied. He testified Petitioner has not provided all data it used to develop TDSIC 2.0 and relies on flawed data and methodologies that cannot be replicated to determine the accuracy of the cost-benefit analysis. Dr. Shull testified Petitioner has failed to demonstrate public convenience and necessity requires upgrades for future DER or renewable projects not yet identified. He testified further that Petitioner has not presented the "best estimate of the cost," as it does not accurately reflect the rising commodity prices. Dr. Shull also testified if TDSIC 2.0 is approved, the nineteen transmission line projects identified as being conducted for redundancy, as well as all DER-related projects, should be removed. He also recommended Petitioner provide biannual reports containing Project Management Institute ("PMI") EVM metrics.

B. **Mr. Lantrip**. Mr. Lantrip testified the OUCC has concerns about the affordability of TDSIC 2.0 and its impact on ratepayers. Mr. Lantrip testified that the Indiana General Assembly declared a policy to protect the affordability of utility services for present and future generations of Indiana citizens through Indiana Code 8-1-2-0.5 when utilities invest in infrastructure necessary for system operation and maintenance. Mr. Lantrip explained that DEI's two billion dollars it is requesting for TDSIC projects includes $837 million in total estimated revenue requirement over the TDSIC 2.0 Project's six-year plan. Mr. Lantrip noted that the TDSIC tracker is one of nine trackers Petitioner uses to periodically adjust customer rates. Mr. Lantrip noted that Petitioner's base rate case in Cause No. 42359, order date May 18, 2004, established a $72.11 monthly residential charge for a customer using 1,000 kWh. This rate was in effect until new rates were established in Cause No. 45253, order dated June 29, 2020. The monthly increase of approximately $51 (71%) was attributed to the Company's various trackers implemented between 2004 and 2019 with no full rate review of other costs or other economic considerations.

Mr. Lantrip testified that in light of the Indiana General Assembly's stated policy, affordability should be a constant consideration for all Indiana jurisdictional utilities, as well as the Commission as it deliberates its decisions. Although safe and reliable utility systems are extremely important, customers are faced with increasing utility costs while contending with hardships worsened during the COVID-19 pandemic. Mr. Lantrip testified the Commission should only approve necessary and reasonable requests from Petitioner to provide service at reasonable prices and take steps to moderate the imposition of higher rates over time.

Mr. Lantrip disagrees with Petitioner's assertion that post-in-service carrying charges ("PISCC") should be calculated at the weighted average cost of capital ("WACC") rate that includes both debt and equity in the carrying charge. He testified that traditionally, post-in-service charges on construction projects have been approved using the current Allowance for Funds Used During Construction ("AFUDC") rate of the utility, not the WACC. Mr. Lantrip testified that Petitioner's proposal to include both debt and equity cost rates for post-in-service deferral is contrary to GAAP. The interest expense related to the debt portion of the PISCC calculation is the only cost that would be charged to expense. The equity portion of PISCC does not get charged to expense and therefore is normally not included in the deferral of post-in-service AFUDC. He testified that the Commission has allowed the equity rate of a carrying charge to be deferred post-in-service in prior cases, including TDSIC cases. Mr. Lantrip testified Petitioner's proposal for deferral treatment of the equity portion allows recovery of more dollars from ratepayers than Petitioner is permitted to record on its income statement. If approved, Petitioner would book a deferred asset for the amount until it is recovered later in a future rate proceeding. Mr. Lantrip testified that the Commission does not have to permit the deferral of the equity portion for future recovery because it does not impact the current financial statements. Unlike debt cost, post-in-service deferral of equity does not improve earnings erosion because GAAP does not permit it to be included on the income statement. He testified that Petitioner has not provided any evidence that it would be in financial distress without the additional deferral of equity.

Mr. Lantrip testified that the OUCC agrees with Petitioner's proposal to recover TDSIC 2.0 expenditures for projects that are in-service at the time of the annual cut-off dates, which is consistent with the methodology in Petitioner's current TDSIC 1.0 Plan. Mr. Lantrip recommended the Commission deny Petitioner's request for recovery of TDSIC 2.0 operation and maintenance ("O&M") expenses as the existence of O&M costs over and above what are currently being recovered through the Rider 65 and in base rates is unsubstantiated. However, if the Commission grants Petitioner's request, Mr. Lantrip recommended that Petitioner should demonstrate that the O&M costs are not duplicative of O&M Petitioner has already received through its general rate case allowance for costs of operation. He testified that improved and replaced assets should, if any change, spur a lower threshold requirement for ongoing O&M costs.

Mr. Lantrip testified the OUCC supports Petitioner's proposal to reconcile forecasted depreciation offsets for retired assets against actual retirements, which benefits ratepayers. He testified that although Petitioner has agreed to recognize the reduction of depreciation expense from the retirement replacement of TDSIC investment embedded in base rates, it has not reduced revenue requirement for embedded net book value of the replaced TDSIC investment used to calculate a return "on" those investments. As a result, Mr. Lantrip testified that Duke Energy Indiana's rates are higher and less affordable than they should be. He testified that reducing revenue requirement for replaced TDSIC investments does reduce timely recovery on the new TDSIC investments. However, it would reduce the overall increase to customers and improve affordability of Duke Energy Indiana's rates. Mr. Lantrip testified that although the TDSIC statute does not specifically prevent the recognition of ratemaking treatment on replaced investments that are still included in base rates, it does not prevent the reality that an excess recovery does occur.

Mr. Lantrip testified, if Petitioner's TDSIC 2.0 Plan is approved, the OUCC recommends (1) the Commission consider the overall affordability of TDSIC 2.0 pursuant to Ind. Code § 8-1-2-0.5; (2) approval of Petitioner's proposed treatment to recover investments in-service as of cut-off date; (3) removal of the equity component from Petitioner's proposal for PISCC treatment to accrue both debt and equity financing on approved capital expenditures from the in-service date until such costs are included in Duke Energy Indiana's rates through Rider 65 or in base rates; (4) limiting recovery of O&M expense to the amount justified by Petitioner as incremental expense above and beyond what was approved in its base rate case, Cause No. 45253; (5) approval of Petitioner's proposal to offset to depreciation expense through a rolling 5-year FERC Form 1 estimated retirement ratio and later reconciliation to actual retirements; and (6) requiring Petitioner to recognize an offset in its revenue requirement for the return earned on the embedded net book value of retired assets which are no longer used and useful.

6. **Hoosier Energy Direct Evidence.** Mr. Mabrey testified Hoosier Energy interconnects with Duke Energy Indiana transmission lines at numerous locations throughout central and southern Indiana pursuant to interconnection agreements. Hoosier Energy serves approximately 51% of its member load off of Duke Energy Indiana owned transmission lines and 15% from Duke Energy Indiana substations. He testified Hoosier Energy has over 350 wholesale delivery points serving 18 distribution cooperatives, which in turn provide electric service to approximately 300,000 retail customers. Increased investment in targeted areas of the transmission system will reduce the number and duration of outages, thus improving overall reliability to Hoosier Energy member systems and their member consumers. Mr. Mabrey testified Hoosier Energy has made investments in the transmission system consistent with Duke Energy Indiana's TDSIC 2.0 Plan to improve reliability, address aging infrastructure, and accommodate additional load growth. He testified Hoosier Energy has worked with Duke Energy Indiana to identify specific transmission and substation upgrades that will impact its members. Investment in reliability, grid hardening and resiliency will greatly help Hoosier Energy and its members by providing more reliable service to its retail customers. Mr. Mabrey testified Duke Energy Indiana's proposed six year TDSIC 2.0 Plan provides a reasonable method of providing such upgrades and improvements.

7. **Duke Energy Indiana's Rebuttal Evidence.** Mr. Lewis submitted rebuttal testimony to Dr. Shull's testimony that Petitioner did not provide all data used to develop the TDSIC 2.0 Plan and that the proprietary Copperleaf modeling logic is unverifiable. He testified that, in addition to the detailed testimony, exhibits, and workpapers filed in this Cause, Petitioner also provided the inputs to the Copperleaf model and arranged two tech-to-tech meetings with the OUCC. Although the Copperleaf model itself is proprietary, the important components to understanding it are the inputs, which were developed by Duke Energy Indiana, provided to B&V, and produced to the OUCC in discovery. Mr. Lewis testified the Copperleaf model was used to optimize the TDSIC 2.0 Plan and is a decision analytics software used for critical infrastructure investment planning across the industry. Mr. Lewis testified that the data provided to B&V was neither "flawed" nor "miscalculated," as Dr. Shull claimed. The functionality underlying the formula calculations required to interpret the data was reviewed and explained to the OUCC. Specifically, the input workbook used the "vlookup" formula to obtain data on related tabs.

In rebuttal, Mr. Lewis testified that Duke Energy Indiana believes it is imperative that Petitioner plan for a future with expanded DER presence. Steadily increasing demand for DER is an ongoing trend in the industry. Petitioner's annual Generation Interconnection Reports submitted to the Commission demonstrate this ongoing increase in the number of DER on Duke Energy Indiana's system, increasing from 43 applications in 2011 to 493 in 2021. He testified that waiting and attempting to design a system around already installed DER is not an effective or efficient way to plan for what is known to be coming, and could delay customer installations and reduce economic development opportunities for Indiana communities. Accommodating two-way power flow capability is needed now to manage and accept customer-generated and stored energy resources, such as wind, solar, and battery storage from customer-owned systems. He testified that Dr. Shull's reactive approach to DER integration on the Duke Energy Indiana system would potentially lead to unacceptable delays for customers with DER (*i.e.* rooftop solar) being able to connect to the grid and sell excess power. Upgrades in distribution capacity (*i.e.* reconductoring projects, new circuits, new substations, etc.) and the ability to handle two-way power flow (*i.e.* SOG, IVVC, etc.) are projects that can take a long time to complete which makes a reactive approach unacceptable from a customer service perspective. He testified the proposed investments related to DER benefit all Duke Energy Indiana customers by reducing outage impacts with respect to frequency, grid impact, recovery time, and cost. Improving system capability to enable DER was not an optimization criterion used in B&V's Cost Benefit Analysis, rather these projects were selected due to their reliability benefits and value to the T&D system as a whole.

Mr. Lewis testified that the TDSIC 2.0 cost estimates are not understated, as suggested by Dr. Shull. Duke Energy Indiana's supply chain organization, in collaboration with PowerAdvocate, evaluated historical component and commodity costs, as well as forecasts of these costs through the duration of TDSIC 2.0. The TDSIC 2.0 cost estimates are built from Class 2 estimates, using rates and estimates obtained mid-2021. Mr. Lewis testified that using 2021 estimates as a baseline, the costs for material, labor, and indirect costs for all projects were escalated at the rate of 3% per year until an individual project's in-service year is reached, through 2028 in some cases. The 3% escalation value was derived from the collaborative mid-2021 study performed by Duke Energy Indiana and PowerAdvocate, which has global industry expertise. Prices increase sharply in the latter half of 2020 and continue to increase until early 2022, in response to the global pandemic and supply chain issues presently impacting all areas of our economy. The projection then shows a general decrease in commodity and utility component costs through 2025, and finally a return to a typical aggregate 3% escalation rate in the outer years of 2026-2028. Petitioner used PowerAdvocate's forecast to develop a reasonable escalation rate for TDSIC 2.0. Mr. Lewis testified that although no one can know with certainty what prices will be in the future, Duke Energy Indiana reasonably assessed the possible range of commodity and component costs to provide a realistic escalation rate for TDSIC 2.0.

Mr. Lewis described the management structure for the TDSIC 2.0 Plan, which is the same as described in Petitioner's TDSIC 1.0 filings. Duke Energy Indiana uses AACE standards and its own Project Management Center of Excellence guidelines, which are consistent with PMI's *A Guide to the Project Manager Body of Knowledge* and the Project Management Professional Certification. Mr. Lewis testified that, similar to TDSIC 1.0, Petitioner will provide annual plan updates upon approval of TDSIC 2.0. The annual updates will include updated project estimates and variances to prior plan estimates, as well as movement of projects between years.

In rebuttal, Mr. Dickey testified that the BES is designed to be highly redundant in order to maintain reliability for all downstream customers served by those transmission lines. BES is subjected to North American Electric Reliability Council's (NERC) mandatory reliability standards, which require sufficient redundancy. He explained that the level of redundancy in the 69kV portion of the transmission system is different from the BES. Mr. Dickey testified that the increased resiliency by the addition of redundant capabilities in TDSIC 2.0 is not referring to building additional redundancy into the BES nor a large-scale redesign of the 69kV transmission system. Rather, these targeted projects within TDSIC 2.0 address specific existing single point of failure vulnerabilities. Several of these projects slightly change the line route to loop through the substation so there is no portion of the transmission line that would prevent restoring power to the substation. This allows the transmission line to be sectionalized by operating switches to isolate faults and restore electric supply to the substation in the event of a line outage. These switches can also be equipped with remote monitoring and control. He testified that these targeted investments are intended to improve reliability and do not create unnecessary or wasteful redundancy. The ability to sectionalize the transmission line and restore power to the substation reduces outage durations to the amount of time required to perform the switching. The TDSIC 2.0 transmission projects will reduce transmission line outages and retail and wholesale customer minutes interrupted ("Grid CMI").

Mr. Dickey testified that the 69kV transmission projects Dr. Shull recommends removed from TDSIC 2.0 are projects to rebuild aged and deteriorated sections of circuits or replace and upgrade specific switches located within other segments of the circuits. These circuits directly supply 25 Duke Energy Indiana substations and 11 substations owned by others. These specific circuits were selected based on a number of factors, including the longer-term history of outages, assessed age and condition of the poles and other equipment, outdated circuit design, and other prioritizing factors. These rebuild projects were, for all but one of these circuits, included in TDSIC 1.0, and the projects included in TDSIC 2.0 continue the longer-term effort to address remaining sections of these lines. He testified that these circuits were selected as being among the highest outage concerns, with a total of 273 outages resulting in 11.78 million Grid CMI from 2015-2021. TDSIC 2.0 will continue to reduce the number of outages on these circuits. Mr. Dickey testified that Duke Energy Indiana has evaluated and selected each of these transmission line rebuild projects to improve reliability by reducing the risk of outages from aged and deteriorated line equipment and performing these projects is in the best interest of Duke Energy Indiana's customers. Each of the projects included in TDSIC 2.0 were evaluated within the model and study performed by B&V and showed a strong reliability improvement due to reduced quantity and duration of outages. He testified that the evaluated reliability benefit justifies and validates the public convenience and necessity of these projects. In addition, these circuit rebuilds will provide a capacity increase between approximately 27% and 123%, due to the larger conductor size. The rebuilt lines will also upgrade and modernize the line by installing optical groundwire as the static shield wire, which includes fiberoptic communications fibers to allow digital telecommunications from one end of the circuit to the other. Mr. Dickey testified that the transmission line rebuild projects that Dr. Shull recommended for removal from TDSIC 2.0 had a condition-based recommendation for pole replacement rate that was two times higher (8%) than the average of Duke Energy's transmission system overall. In addition, although not expressed directly as CI or CMI reduction, the B&V model used to evaluate and prioritize projects for inclusion in TDSIC 2.0 showed these projects to have significant reliability benefits, averaging 4.1 times the cost of the projects. Mr. Dickey testified that transmission line outages can result in more CMI than distribution outages and TDSIC 2.0 helps mitigate CMI associated with those outages.

In rebuttal, Ms. Diaz testified that the 2% rate impact limit included in the TDSIC statute protects customers from rate impacts associated with TDSIC investments and safeguards affordability. Under the TDSIC statute, utilities must petition for a retail rate case before the expiration of the TDSIC plan life. Therefore, a full review of Duke Energy Indiana's basic rates and charges will occur in conjunction with TDSIC 2.0. Ms. Diaz testified that affordability and rate competitiveness are critical metrics for Duke Energy Indiana, noting Petitioner's overall retail average realization continues to be below national and regional averages and is the lowest among its Indiana peers.

Ms. Diaz testified in response to Mr. Lantrip's assertion that Ind. Code § 8-1-39-9 does not provide necessary authority to request PISCC treatment for both debt and equity because it does not define PISCC. She testified Ind. Code § 8-1-39-9 explains that the deferral of the remaining 20%, which includes post-in-service carrying costs, aligns with the rest of the recovery applicable to the 80%, which is included in the TDSIC Rider. In other words, the 80% includes post-in-service carrying costs. The weighted average cost of capital language is interspersed in the TDSIC statute and does not limit the calculations to debt only. In addition, it is common practice for pretax returns and the weighted average cost of capital to include both debt and equity. Ms. Diaz testified that GAAP provides that both the debt and equity return can be deferred as a regulatory asset for post-in-service capitalization. Accrual of financing costs at the weighted average cost of capital, which includes an equity component along with debt, represents the comprehensive cost incurred by the Company for the period after the assets are placed in service until the collections occur. The TDSIC statute does not prohibit the application of an equity component in the PISCC calculation, and the Commission has approved the equity component in prior TDSIC cases. Ms. Diaz testified that there is no requirement under Indiana law that Duke Energy Indiana make a showing of financial distress without the additional deferral of equity, as suggested by Mr. Lantrip, and the Commission should not require it now.

Ms. Diaz testified that the TDSIC Rider limits the recovery to incremental O&M and no additional supporting documentation is needed to ensure there is no duplication of O&M expenses recovered in Petitioner's most recent base rate case, Cause No. 45253. None of the TDSIC 2.0 projects were included in Cause No. 45253, therefore none of the related project O&M would have been allowed to be included as the Commission approved O&M costs representative of the test year, 2020. The TDSIC 2.0 project O&M begins three years later and beyond and is directly related to TDSIC 2.0 capital projects. Because these costs are occurring after installation of the assets, Duke Energy Indiana expenses the O&M. Ms. Diaz testified that Petitioner's TDSIC 1.0 case allows the inclusion of O&M costs, and TDSIC 2.0 has not proposed any different treatment of O&M costs than what has been approved for TDSIC 1.0. She testified that Petitioner did not include any duplicative O&M in this proceeding.

Ms. Diaz testified that Petitioner and Mr. Lantrip agree that implementing depreciation netting is appropriate for TDSIC 2.0. Similar to NIPSCO's approved proposal on depreciation netting, Duke Energy Indiana will use an average rate of retirement percentage based on actual FERC Form 1 data as the source for the depreciation expense credits. Ms. Diaz disagreed with Mr. Lantrip's recommendation that Duke Energy Indiana recognize an offset in its revenue requirement for the return on net book value of retired assets as a result of the TDSIC 2.0 Plan. She testified that Petitioner is not proposing any different treatment than was approved in TDSIC 1.0. In other TDSIC cases, the Commission has specifically ordered that double-recovery concerns are addressed by depreciation netting methodologies, which Petitioner has proposed in TDSIC 2.0. The Commission likewise concluded that reductions to returns on retired assets in rate base were not reasonable and did not conform to the TDSIC statute.

8. **Cross Examination Evidence.** Mr. Pinegar testified he agreed the definition of "the best" as used in Ind. Code §8-1-10(b)(1) means, "excelling all others", "the greatest degree of excellence", and "none can be better." [Cross Examination of Stan Pinegar, A-18:14-20.] Mr. Pinegar noted that Duke Energy Indiana began its analysis of TDSIC projects in 2019. [A-19:1-2.] Mr. Pinegar also stated that he is aware of the rising commodity costs and testified that even after it noted the rising commodity costs, the Company did not perform a new cost estimate. [A-21:1-2.] Mr. Pinegar acknowledged that Duke Energy Indiana's system, as it is today – is reliable. [A-31:22-24.] Mr. Pinegar agreed that to meet the CPCN requirement in the TDSIC Statute, the Company must show a "need" for the TDSIC projects. [A-30:10-13.] Mr. Pinegar stated that his goal as Duke Energy Indiana's President was to cap the costs of this TDSIC Plan at one percent to make it more affordable. [A-40:2-5.] Mr. Pinegar stated he does not view the TDSIC Projects as set in stone [A-40:8], and if costs continue to rise, Duke Energy Indiana will delay doing projects. [A-41:2-7.] Mr. Pinegar also stated that Duke Energy Indiana would not "inch closer to the $4 billion mark;" and that it "would take Commission approval to add projects and inch closer to the 2 percent or $4 billion mark." [A-41:8-14.] Mr. Pinegar agreed on cross examination that in 2020 DEI had a 1.25 SAIFI rating, and a seventeen percent decrease in SAIFI as argued by the Company still equates to a number greater than 1 – meaning on average Duke Energy Indiana's customers would still experience on average one interruption lasting longer than five minutes. [A-55:12-56:24.]

Mr. Lewis admitted on cross examination that: Duke Energy Indiana met with PowerAdvocate in 2021 before filing its TDSIC Plan; PowerAdvocate provided the Company a PowerPoint that showed without question that Duke Energy Indiana's 100% cost estimate for material components were estimated far lower than actual or projected material component costs. [See OUCC CX-4 and OUCC CX1-C.] Mr. Lewis admitted that once Duke Energy Indiana had updated information from PowerAdvocate, Duke Energy Indiana added the three percent cost escalation, and Petitioner felt that the three percent escalation covered PowerAdvocate's material component fluctuations in price. [See Cross Examination of Mr. Lewis; B-55:5-18.] Mr. Lewis admitted on cross examination that he had never spoken with any customers regarding customer wants or needs related to DER. [B-32:25-B33:9.] Mr. Lewis also admitted that he had not had communications with anyone at Duke Energy Indiana to determine why it believes that such upgrades for DER are necessary. [B-30:19-22.]

Mr. Dickey admitted on cross examination regarding data requests that Duke Energy Indiana did not provide outage data for various projects. [See OUCC CX-9.] Mr. Dickey stated that he and Petitioner did not know the algorithm contained in the modeling from B&V, and Duke Energy Indiana itself could not replicate the B&V and Copperleaf findings. [See Cross Examination of Mr. Dickey, C-24:10-25.] Mr. Dickey could not point to indices in which it is proper to measure transmission systems using SAIDI and SAIFI, and could not refute that the IEEE 1366 Index regarding SAIDI and SIAFI is only used for distribution systems and not transmission systems. [C-15:17-25; C-18:5-7; Public's Ex. No. CX-8.] Mr. Dickey admitted that he has no indices or treatises that recognize "Grid CMI" as a proper measurement of transmission improvement. [C-60:4-20.]

Mr. Shields admitted in cross examination that he did not make a determination that Petitioner's cost estimates were "the best", he only evaluated ***some*** of the projects based on "reasonability." [See Cross Examination of Mr. Shields, C-60:4-19.]

9. **Statutory Requirements.** Ind. Code § 8-1-39-10 (the "TDSIC Statute") permits a public utility to petition the Commission for approval of the utility's TDSIC plan for eligible transmission, distribution, and storage improvements, which may include for approval of a TED project. The Commission's order must include: (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; and (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 TDSIC plan is reasonable, it 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).

Ind. Code § 8-1-39-2(a) defines "eligible transmission, distribution, and storage system improvements" as 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 described in the public utility's TDSIC plan and approved by the Commission under Ind. Code § 8-1-39-10 and authorized or TDSIC treatment; or approved as a TED project under Ind. Code § 8-1-39-11. Under Ind. Code § 8-1-39-2(b), the term "eligible transmission, distribution, and storage system improvements" includes: (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 § 8-1-39-7.8 requires that a TDSIC plan cover a period of at least five years and not more than seven years.

Ind. Code § 8-1-39-9(d) provides that a public utility may not petition the Commission for approval of a utility's TDSIC plan within nine months after the date of a Commission order changing the utility's basic rates and charges with respect to the same type of utility service.

Ind. Code § 8-1-2-0.5 requires that the Commission must use all practicable means and measures to protect the affordability of utility services for present and future generations of Indiana citizens when utilities plan for investment in infrastructure.

Ind. Code § §8-1-2-6 requires that a utility must show that its property is used and useful.

10. Commission Discussion and Findings.

A. Duke Energy Indiana's TDSIC 2.0 Plan and Eligible Improvements.

OUCC witness Dr. Shull challenged the sufficiency of Duke Energy Indiana's TDSIC 2.0 Plan, as Petitioner did not provide outage data or any empirical evidence showing the necessity of any of its proposed TDSIC projects. Dr. Shull was particularly concerned with the inclusion of nineteen transmission line projects arguing that they are not for purposes of safety, reliability, or modernization. Duke Energy Indiana's witnesses admitted Petitioner did not provide historical outage data to show the necessity of such projects. Duke Energy Indiana also failed to provide in its case-in-chief that any of the 19 transmission projects provided capacity upgrades or were at the end of their useful lives. Mr. Dickey attempted to rebut Dr. Shull's testimony by claiming that those circuits directly supply 25 Duke Energy Indiana substations and 11 substations owned by others. However, such improvements to other utilities' substations does not show the benefit to the Company's customers, as required by the Statute (Ind. Code §8-1-39-10(b)(3). Additionally, Duke Energy Indiana is required to show the necessity of such improvements in its case-in-chief testimony. Duke Energy Indiana attempts to get additional data it failed to provide in its case-in-chief testimony in its rebuttal testimony, however, Duke Energy Indiana is reminded that rebuttal evidence is limited to evidence to explain, contradict, or disprove evidence offered by the adverse party, it is not an opportunity to correct deficiencies in Petitioner's case-in-chief.

The Commission also heard testimony that Duke Energy Indiana worked with its stakeholders to identify projects to be considered for TDSIC 2.0. However, on cross examination Mr. Lewis admitted that he had never spoken with a customer regarding the TDSIC Plan. In spite of several consumer groups being represented by counsel, no consumer groups filed any testimony in support of any projects. Hoosier Energy witness Mr. Mabrey testified, at the evidentiary hearing, that Hoosier Energy and Duke Energy Indiana worked together to identify certain improvements that provide benefits to Duke Energy Indiana retail customers while also benefiting the larger grid, Hoosier Energy, its member systems and their consumers. However, Mr. Mabrey could not identify any specific project in its prefiled testimony or at the evidentiary hearing that it requested inclusion of in the Company's TDSIC Plan. Therefore, it remains that no Duke Energy Indiana customer testified in support of any project improvement, and Duke Energy Indiana's discussion in testimony surmounts to hearsay and speculation of customer wants.

OUCC witness Dr. Shull also challenged Duke Energy Indiana's addition of electrical system devices for future DER installations, testifying that Petitioner had not demonstrated a customer demand for DER, and it would be prudent to wait and build its system when customers seek interconnection. Dr. Shull further testified Petitioner has not demonstrated a customer demand for DER, and it would be prudent for Duke Energy Indiana to wait and build its system to meet specific customers' DER needs. In rebuttal, Duke Energy Indiana argued that the enablement of DER was an ancillary benefit to the Company's proposed TDSIC 2.0 investments with the primary benefit being reliability. Specifically, Mr. Lewis testified that the proposed investments that also impact DER benefit all Duke Energy Indiana customers by reducing outage impacts with respect to frequency, grid impact, recovery time, and cost. However, no direct evidence was provided regarding the outage impacts or costs, outside of the DER analysis. Further, Mr. Lewis explained that improving system capability to enable DER was not an optimization criterion used in B&V's Cost Benefit Analysis, rather these projects, which result in two-way power flow capability, were selected due to their reliability benefits and value to the T&D system. Nonetheless, Petitioner did not provide any direct evidence related to interconnection requests, or where such DER was to be built in relation to the proposed TDSIC projects to enable DER. While Duke Energy Indiana states that such an approach to install additional two-way power flow, with other benefits, is a "proactive" approach, we are reminded that all such utility plant must meet with the statutory requirement that it be "used and useful." The Court of Appeals has long held that "[u]nnecessary plant capacity is not used and useful for rate making purposes and should not be included." *Indiana-Am. Water Co. v. Ind. Off. Of Util. Consumer Couns*., 844 N.E.2d 106, 111 (Ind. Ct. App. 2006) *citing L.S. Ayres & Co. v. Indpls. Power & Light Co*., 169 Ind. App. 652, 683, 351 N.E.2d 814, 834 (1976), *trans. denied.* In that case, Indiana American provided testimony that a fifth water pump was needed to meet peak demand and noted that the fifth pump had not yet been used but claimed it will be needed "at some point in the future." *Id*. at 111 (Emphasis added.) The Commission in its findings noted that, despite previously allowing this pump into rate base, the Commission:

> [S]hall make our decision based on the evidence of record that we now have before us. We find that [IAWC] did not provide evidence to support the time frame within which this engineering feature will be used and useful. Further, we find [IAWC's] evidence lacked information that we deem necessary in order to allow this plant in rate base. *Id*.

Based on the evidence presented, we find Duke Energy Indiana has not met its burden of proof to show that such DER projects will be used and useful. Petitioner did not provide any time frame within the record to show when such DER projects would be used and useful. Consistent with the Commission's prior ruling in *Indiana-American*, in which the Court of Appeals upheld the Commission's decision to deny speculative needs for future demand, the Commission denies Duke Energy Indiana's request herein.

B. **<u>Best Estimate of Costs</u>.** Ind. Code § 8-1-39-10(b)(1) requires that the Commission's order on a TDSIC Plan must include "[a] finding of the best estimate of the cost of the eligible improvements included in the plan."

Duke Energy Indiana's TDSIC 2.0 proposes six years of defined investment totaling $2,140,185,171. The record demonstrates that $1,144,816,889 of the total cost estimate is distribution cost; $1,837,552,403 is transmission cost; and potentially $157,815,879 of targeted economic development project cost. Exhibit 2-A provided year-by-year cost estimates and an associated summary of the TDSIC 2.0 Plan's cost by FERC account.

Duke Energy Indiana developed cost estimates for the projects included in TDSIC 2.0 using the AACE Cost Classification System. As a general matter, Duke Energy Indiana presented Class 2 cost estimates for many of the proposed projects for Plan Years 1 and 2. Class 3 and Class 4 estimates were developed for the remaining projects. Duke Energy Indiana's confidential workpapers included electronic spreadsheets underlying the sortable list. Duke Energy Indiana's confidential workpapers also included the cost estimates for TDSIC 2.0 projects. Examples of the Class 2, 3, and 4 cost estimates were provided in Duke Energy Indiana's Confidential Exhibits 2-B and 3-A.

The Commission has not in previous TDSIC cases determined what "the best estimate of cost" means, as used in the TDSIC statute. Indiana Courts have consistently held that "when a statute is clear and unambiguous, we apply the rules of statutory construction and interpret statutory language in its plain, ordinary, and usual sense." *Cty. of Lake v. Pahl*, 28 N.E.3d 1092, 1104 (Ind. Ct. App. 2015), *reh'g denied, trans. denied*. Petitioner's witness Stan Pinegar accepted that "the best" as referenced in the Statute, means, "excelling all others", "the greatest degree of excellence", and "none can be better." [Cross Examination of Stan Pinegar, A-18:14-20.] OUCC witness, Dr. Shull, asserts that Petitioner has not accurately accounted for recent increases in commodity prices and inflation rates and thus has not presented the "best estimate of the cost." Additionally, OUCC Ex. CX-C1 demonstrates that Duke Energy Indiana's cost estimates included in its TDSIC Plan were underestimated, even from its own estimations, at the time of filing the Company's TDSIC 2.0 Plan. While Duke Energy Indiana speculates a three percent escalation will cover the rising costs, its own futures predictions show this is not accurate. While Duke Energy Indiana's non-engineering witnesses, Mr. Dickey and Mr. Lewis stated that Duke presented the best cost estimates, neither are engineers qualified to make such a statement. Indeed, Petitioner's only engineer witness specifically noted that he could not state Duke Energy Indiana's estimates were "the best"; he only reviewed the estimates for "reasonableness." As Duke Energy Indiana presents no engineering witness to rebut Dr. Shull's assessment that the cost estimates are not "the best estimate of costs", and as the Company's cost estimates fail to account for the 30-55 percent shift in material component costs, Duke Energy Indiana has failed to meet the statutory requirement. The statute does not require "reasonableness" as Duke Energy Indiana seems to argue, the statute expressly requires "the best." Mr. Lewis explained that Duke Energy Indiana used its mid-2021 estimates as baselines for the costs of material, labor, and indirect costs for all projects were escalated at the rate of 3% per year until an individual project's in-service year was reached, through 2028 in some cases. The escalation value of 3% was derived from the collaborative mid-2021 study performed by Duke Energy Indiana and PowerAdvocate. Mr. Lewis testified that Duke Energy Indiana and PowerAdvocate observed prices increasing sharply in the latter half of 2020 and continue to increase until early 2022. The projection then shows a general decrease in commodity and utility component costs through 2025, and finally a return to a typical aggregate 3% escalation rate in the outer years of 2026 – 2028. Petitioner does not adjust any of its proposed material component acquisitions for 2022, and merely speculates that by 2026 the number will level out. However, the Plan requires material components to be purchased far ahead of 2026. Duke Energy Indiana argues that it used PowerAdvocate's forecast to develop a reasonable escalation rate for TDSIC 2.0. Again, Duke Energy Indiana is not required to provide a "reasonable" forecast or a "reasonable" estimate, the statutory language is explicit, cost estimates must be "the best." Duke Energy Indiana fails to rebut the argument of Dr. Shull, as the sole engineering witness in this case, who determined Petitioner's cost estimates were not "the best estimate of costs." Additionally, even if the standard were "reasonableness", Petitioner's estimates with stale cost estimates do not represent a reasonable estimate, as demonstrated by PowerAdvocate's presentation showing Duke Energy Indiana's estimates were far lower than actual or projected costs.

Based on the evidence presented, we find that Duke Energy Indiana only addresses the "reasonableness" of cost estimates and does not properly consider the Statute's explicit requirement of "the best estimate of costs." Accordingly, we find that Duke Energy Indiana has failed to provide the best estimate of costs.

C. <u>Public Convenience and Necessity</u>. Ind. Code § 8-1-39-10(b)(2) requires that an order on a TDSIC plan must include "[a] determination whether public convenience and necessity require or will require the eligible improvements included in the plan."

Duke Energy Indiana argues that the Distribution System Circuit Improvements portion of TDSIC 2.0 (which accounts for $704,060,933 (direct capital) of TDSIC 2.0) is largely intended to focus on value to the customer through replacement of the aging assets and expansion of technology to modernize Duke Energy Indiana's electric grid with technologies that support improved reliability. Program categories include Circuit Backbone Reliability Uplift, Overhead Lateral Reliability Uplift, Underground System Uplift, 4kV Conversion, and Inspection Based Programs. The evidence of record further demonstrates that the Distribution System Substation Improvements portion of TDSIC 2.0 (which accounts for $176,965,506 (direct capital) of TDSIC 2.0) is largely intended to improve reliability and resiliency, while improving capacity, though various Substation Hardening & Resiliency sub-programs. Duke Energy Indiana further argues that the Transmission System Line Improvements portion of the of TDSIC 2.0 (which accounts for $494,662,048 (direct capital) of TDSIC 2.0) is intended to improve reliability and flexibility through various Line Hardening & Resiliency sub-programs. The evidence demonstrates that the Transmission System Substation Improvements portion of the of TDSIC 2.0 (which accounts for $198,038,203 (direct capital) of TDSIC 2.0) is intended to improve reliability and resiliency, while improving capacity, though various Substation Hardening & Resiliency sub-programs.

The OUCC argued that some of the eligible improvements included in TDSIC 2.0 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. Dr. Shull asserted that the Petitioner claims its system is already highly redundant and reliable and has provided no support for an added layer of redundancy. Dr. Shull further stated that Duke Energy Indiana's proposed level of additional redundancy is unnecessary and not supported by evidence. Specifically, Dr. Shull stated that the Company has not shown any historical data or other support showing it needs this added layer of redundancy. Additionally, Duke Energy Indiana Witness Dickey admitted in data responses, Petitioner did not provide such outage data. Without such evidence Duke Energy Indiana cannot show a need for these projects. Dr. Shull also testified regarding seventeen transmission line projects in which Petitioner failed to provide empirical evidence or support that the public convenience and necessity requires the replacement or rehabilitation of such transmission lines to improve reliability. Dr. Shull testified that those transmission projects are not necessary replacements for improved reliability. Duke Energy Indiana presented no direct evidence regarding any capacity changes or other upgrades. The projects are merely replacing undeteriorated transmission lines, with the exact same equipment. Further, Duke Energy Indiana provides no evidence that these specific projects result in a reduction in customer interruption or customer minutes interruption or improved reliability.

Petitioner failed to provide evidence, such as outage data, or other empirical evidence to show a need for such projects. Petitioner has failed to demonstrate that all requested projects are necessary. Unnecessary projects are never affordable.

D. **<u>Incremental Benefits Attributable to the TDSIC 2.0 Plan</u>.** Ind. Code § 8-1-39-10(b)(3) requires that an order on a petition for approval of a TDSIC plan must include "[a] determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan."

Duke Energy Indiana, with the assistance of B&V, included non-financial "benefits," and attempted to monetize such "benefits" from the customer experience perspective, the value of avoiding service outages, particularly CI and CMI. However, Mr. Shields admitted on cross examination that such "benefits" including "customer satisfaction" did not even consider rising electric costs. Mr. Shields explained that B&V's Investment Plan Analysis began with detailed benefit mapping, as depicted in Table 3 and Table 4 of his direct testimony. Duke Energy Indiana's analysis did not attempt to quantify all project benefits. Duke Energy Indiana's internal team identified 57 projects that could not pass even its own cost-benefit test, but were included in TDSIC 2.0 because they impacted critical customers, such as hospitals and schools. The Company used B&V's "Value Model" incorporating Copperleaf's modeling to determine a cost-benefit analysis. Projects that scored at or above 1.0 had, in Duke Energy Indiana's model, benefits that outweighed the associated costs.

The OUCC argued that the Commission should deny the TDSIC 2.0 Plan due to the inability of any party or the Commission to verify the reasonableness or accuracy of B&V's

Copperleaf modeling logic that selected the projects contained in TDSIC 2.0. Dr. Shull testified that it is impossible to verify whether Copperleaf's modeling logic is reasonable, or the calculations are accurate. The Commission agrees with Dr. Shull. Not only can no party verify the Plan, Duke Energy Indiana itself admitted in cross examination that it cannot verify the findings of Copperleaf as it does not know Copperleaf's algorithms. We also question the potential inflation of benefits used in B&V's "Value Models". Such non-financial "benefits" appear to be duplicative, and fall far outside of the traditional cost-benefit analyses that have been approved by the Commission in other TDSIC cases.

Accordingly, based on the evidence presented, we find that Duke Energy Indiana has not presented sufficient evidence to show that the costs presented outweigh the benefits of its TDSIC 2.0 Plan.

E. Affordability. The Indiana General Assembly has made a policy declaration to use all practicable means and measures in a manner calculated to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services for present and future Indiana citizens. Ind. Code § 8-1-2-0.5. Thus, if the General Assembly declared its policy to protect affordability, the Commission must consider the affordability of this Plan. The statutory declaration to consider affordability is another layer of protection that the Indiana General Assembly enacted to protect ratepayers. This policy consideration that affordability must be protected while investments are made in infrastructure is in addition to the constraint of the two percent cap included in the TDSIC Statute. As the Commission herein finds in consideration of the unsurety of the costs of the Plan, the undefined and potentially inflated benefits, the inability of any party or the Commission to replicate the Copperleaf findings, the failure to show the necessity of the projects, and the general overall economic concerns of ratepayers, the Commission rejects Petitioner's Plan as insufficient to protect affordability as required by Ind. Code § 8-1-2-0.5.

F. Accounting and Ratemaking. As summarized above, Duke Energy Indiana requests Commission approval to recover 80% of the TDSIC 2.0 costs via its existing approved TDSIC Rider that uses the class revenue allocation factors based on firm load developed in the most recent base rate case in Cause No. 45253, and deferral with carrying costs of 20% of the TDSIC 2.0 costs for subsequent recovery in Petitioner's next general retail electric base rate case. The Commission approved Duke Energy Indiana's electric TDSIC mechanism in its 44720 Order, allowing for the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorization to defer, until recovery though the TDSIC, 80% of the post-in-service TDSIC costs of the TDSIC projects, including carrying costs, depreciation, O&M expenses, and taxes.

As provided for in Ind. Code § 8-1-39-13(b), Duke Energy Indiana requests authority to increase the authorized net operating income for purposes of the Ind. Code § 8-1-2-42(d)(3) earnings test. Based on our review of the TDSIC Statute, our discussions above regarding transmission upgrade projects, DER systems projects, the absence of the "best estimate" of project costs as required by Ind. Code §8-1-39-10(b)(1), insufficient evidence demonstrating the public convenience and necessity require, or will require, the proposed projects as required by Ind. Code §8-1-39-10(b)(2), the failure to demonstrate the Plan's estimated costs are justified by incremental benefits attributed to the Plan as required by Ind. Code §8-1-39-10(b)(3), and our conclusion that the Plan as proposed is inconsistent with Indiana's state policy for protecting affordability of utility service as set forth in Ind. Code §8-1-2-0.5, we find that Duke Energy Indiana's request should be denied. While this decision may technically render further discussion on ratemaking and accounting issues moot, there are important issues here which should be addressed in the interest of providing guidance to Duke Energy Indiana should it decide at some later date to file a new TDSIC Plan with this Commission.

i. **Post In-service Carrying Costs.** Duke Energy Indiana seeks approval for the accrual of post-in-service carrying costs, which includes both debt and equity financing, on approved capital expenditures, including accrual on previously computed post-in-service carrying cost amounts, from the in-service date until such costs are included in the Company's rates under TDSIC or in base rates. These carrying costs will accrue at rates equal to Duke Energy Indiana's most recently approved weighted average cost of capital. AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates, or when the projects are placed in service. Ms. Diaz testified that Duke Energy Indiana also seeks Commission authority to create regulatory assets to recover post-in-service carrying costs, O&M, depreciation, and property taxes associated with the projects until such costs are reflected in the TDSIC tracker rates or Duke Energy Indiana's retail electric rates.

OUCC witness Mr. Lantrip argued Duke Energy Indiana should be able to include only the debt financing in its post-in-service carrying costs. On rebuttal, Ms. Diaz stated that the TDSIC Statute does not prohibit the application of an equity component, and GAAP provides for both debt and equity return deferral as a regulatory asset. She further stated that the Commission has approved both the equity and debt components in prior TDSIC cases.

We find the OUCC's position most persuasive. Ind. Code §8-1-39-9(b) does not specify that PISCC costs must include both the debt and equity components. The Commission has previously approved calculating PISCC costs using the Allowance for Funds Used During Construction ("AFUDC") rate of the utility, as opposed to the WACC (which includes an equity component) as proposed by Petitioner. See the Commission's Order in Cause No. 44339. Petitioner's proposal is contrary to GAAP, which GAAP does not permit the capitalization of incurred costs that are not charged to expense. Accounting Standards Codification ("ASC") 980-340-25-1 states, in part, "An enterprise **shall capitalize all or part of an incurred cost that would otherwise be charged to expense**…" (emphasis added). With respect to PISCC costs, the only cost that would be charged to expense is the interest expense related to the debt portion of the PISCC calculation. The equity portion of PISCC does not get charged to expense and therefore is normally not included in the deferral of post-in-service AFUDC. Unlike debt cost, post-in-service deferral of equity does not improve earnings erosion because GAAP does not permit the equity portion to be included on the company's income statement. Duke Energy Indiana's proposal allows the company to recover more dollars from ratepayers than it would be permitted to be recorded on its income statement.

Petitioner is correct that the Commission has, in other TDSIC cases, included the equity portion of deferred expenses in the PISCC calculation. However, the Commission is not required by the TDSIC statute to do so, nor are we bound to blindly follow a prior decision. Every case is impacted by the particular circumstances, evidentiary record and controlling statutes, with prior orders potentially influencing our decision as well. Considering the unprecedented cost of the Company's proposed Plan, the applicable GAAP rules, the Commission's discretion on this topic (Ind. Code §8-1-39-13(a)(5) explicitly allows consideration of "other information" in calculating TDSIC costs), our increased focus on Indiana's affordability statute, and the absence of evidence from the company it will suffer financial distress without the PISCC associated with the deferred equity, we would deny the company's proposed request if we had approved other portions of the Plan.

ii. **Plan Development Costs.** Duke Energy Indiana has requested recovery of the expenses incurred for retaining B&V as a consultant and witness for this proceeding. B&V performed analyses as part of this proceeding, and Mr. Shields provided testimony that summarizes these analyses. Based on the evidence provided in this case, and the absence of objections by any other party, we would have found this to be a reasonable request.

iii. **Depreciation.** Ms. Diaz also explained that Duke Energy Indiana's proposal regarding depreciation on TDSIC 2.0 projects and stated that Duke Energy Indiana is proposing to utilize the applicable depreciation rates for transmission and distribution assets approved in its most recent rate case, Cause No. 45253. Ms. Diaz is also proposing to offset depreciation expense for retired plant using a five-year average of FERC Form 1 retirement ratios. Evidence provided by Ms. Diaz in Exhibit 6-A demonstrates that TDSIC 2.0 does not result in an average aggregate increase in Duke Energy Indiana's total retail revenues of more than two percent in a 12-month period. As no party presented evidence challenging this requested relief, we would have found Duke Energy Indiana's proposals reasonable.

iv. **Recovery of Operation and Maintenance (O&M) Expense**. Mr. Lantrip recommended the Commission deny Duke Energy Indiana's request for recovery of \$131M in O&M expenses. Public's Ex. No.1 at 14. Mr. Lantrip argued existing plant in rate base already has O&M embedded in rates, while new TDSIC improvements that replace existing plant should require less O&M, not more, and the embedded O&M in current rates isn't being used for O&M on the replaced plant that is no longer in service and used and useful. He also testified as to Petitioner's lack of evidentiary support demonstrating the requested \$131M was above and beyond the O&M expenses embedded in its base rates (from Cause No. 45253). Ms. Diaz's rebuttal testimony stated that the O&M in this case is project specific to the TDSIC 2.0 projects and has not been included in the prior TDSIC 1.0 plan nor was it included in Duke Energy Indiana's most recent base rate case, Cause No. 45253.

Ind. Code §8-1-39-2(a)(2) requires eligible TDSIC improvements are "not included in the public utility's rate base in its most recent general rate case." "TDSIC costs" which may be recovered for eligible improvements (defined in Ind. Code §8-1-39-7 and which include O&M) therefore, also cannot be included in the public utility's rates set in the most recent general rate case. Petitioner has the burden of proving the proposed TDSIC improvements and their associated costs are not part of the utility's existing rate base or rates. This burden falls on no other party.

The Company's self-serving assurances, whether in data request responses or testimony, that none of the $131M in requested O&M is included in base rates are inadequate to meet its evidentiary obligation absent any other objective, verifiable supporting evidence. Arguing that a project's construction began three years after the most recent rate case is not proof that expenses for that project are not part of existing rates. Pole replacement programs might be one such example.

Duke Energy Indiana's requested $131M in O&M ignores the fact that the company will be simultaneously recovering from ratepayers, in base rates, O&M for all existing plant that is replaced, removed from service and is no longer used and useful as part of the Plan. Traditional ratemaking would not typically remove retired / replaced plant from rate base outside of a general rate proceeding. Thus, ratepayers will continue to pay to maintain plant that provides them no service and no benefit. This outcome directly contradicts the purpose of Indiana's affordability statute. Had we not reached our earlier case-dispositive decisions, this topic would seem to be another area ripe for Commission consideration under Ind. Code §8-1-39-13(a)(5), including a potential adjustment the calculation of an appropriate pre-tax return as we discussed in our Order in AES Indiana's TDSIC Plan, Cause No. 45264.

v. **Retirement of Replaced Assets.** Mr. Lantrip recommended that Duke Energy Indiana recognize an offset in its revenue requirement for the return earned on the embedded net book value of retired assets. On rebuttal, Ms. Diaz noted that the Commission has previously rejected this recommendation, and the Commission has specifically approved depreciation netting methodologies to address this issue.

Similar to our discussion above regarding O&M, traditional ratemaking would not typically remove retired / replaced plant from rate base outside of a general rate proceeding. Thus, ratepayers continue to pay a return "on" the net book value, as well as a return "of" the replaced / retired plant that provides them no service and no benefit. Once again, this outcome directly contradicts the purpose of Indiana's affordability statute. This causes Duke Energy Indiana's rates to be unnecessarily higher and less affordable. While the Commission has previously considered and rejected OUCC's position on this issue in prior TDSIC plan cases, the individual circumstances of this case, with this evidentiary record, are such that had we not reached our earlier case-dispositive decisions, this topic would also be ripe for Commission consideration under Ind. Code §8-1-39-13(a)(5). A potential adjustment the calculation of an appropriate pre-tax return, as we discussed above, might well be in order. Cause No. 45264.

11. <u>Confidential Information</u>. On November 23, 2021 and February 25, 2022, Petitioner filed motions requesting protection of confidential and proprietary information along with supporting affidavits showing the documents to be submitted to the Commission contained confidential, proprietary, competitively sensitive, and/or trade secrets as defined under Ind. Code §§ 23-2-3-2 and 5-14-3-4. On December 1, 2021, and March 4, 2022, the Presiding Officers preliminary determined that trade secret information should be subject to confidential procedures, as supported by Petitioner's affidavits. The Commission finds all such information preliminarily granted confidential treatment is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and should be held by the Commission as confidential and protected from public access and disclosure.

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

1. Duke Energy Indiana's TDSIC 2.0 Plan is denied.

2. The information Petitioner filed in this Cause pursuant to motions for confidential treatment, as discussed in Finding No. 11 above, is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, exempt from public access and disclosure by Indiana law, and will be held by the Commission as confidential and protected from public access and disclosure.

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

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

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

____

Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, LLC FOR; (1) APPROVAL OF PETITIONER'S 6-YEAR PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10; (2) APPROVAL OF A TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT AND DEFERRALS, PURSUANT TO IND. CODE §§ 8-1-2-10, 8-1-2-12, 8-1-2-14, AND 8-1-39-1 *ET SEQ*; AND (3) APPROVAL OF A TARGETED ECONOMIC DEVELOPMENT PROJECT AND RECOVERY OF COSTS ASSOCIATED WITH THE PROJECT, PURSUANT TO IND. CODE §§ 8-1-39-10 AND 8-1-39-11	)	**CAUSE NO. 45647**

<u>ORDER OF THE COMMISSION</u>

<u>Presiding Officers</u>:
David L. Ober, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

On November 23, 2021, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company" or "Petitioner") filed a Verified Petition requesting approval of its six-year plan for eligible transmission, distribution, and storage system improvements, pursuant to Ind. Code § 8-1-39-10, including specific targeted economic development ("TED") projects pursuant to Ind. Code §§ 8-1-39-10 and 8-1-39-11 ("TDSIC 2.0 Plan" or "TDSIC 2.0"), and for transmission and distribution infrastructure improvement cost rate adjustment and deferrals pursuant to Ind. Code § 8-1-39-9. Also on November 23, 2021, Duke Energy Indiana prefiled Petitioner's case-in-chief, which included the direct testimony and exhibits of the following witnesses:

- Stan C. Pinegar, President, ~~at~~ Duke Energy Indiana;
- Jeremy K. Lewis, Director of Customer Delivery Project Management at Duke Energy Business Services, LLC ("DEBS");
- Martin D. Dickey, Vice President, Transmission Construction & Maintenance at DEBS;
- James W. Shields, Principal Consultant at Black & Veatch Management Consulting LLC ("B&V");
- Erin Schneider, Director of Economic Development at Duke Energy Indiana; and
- Maria T. Diaz, Director, Rates and Regulatory Planning at Duke Energy Indiana.

Petitioner filed a motion for protection of confidential and proprietary information that was preliminarily granted on December 1, 2021. Petitioner filed revised testimony of Mr. Lewis on December 14, 2021.

Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), Duke Industrial Group ("Industrial Group"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy"), Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance ("Wabash Valley"), and Steel Dynamics, Inc. ("SDI") each filed petitions to intervene, all of which were subsequently granted.

On December 2, 2021, the Commission issued a Docket Entry creating a subdocket (Cause No. 45647 S1) for the purpose of reviewing the proposed TED ~~project, and~~project and establishing its procedural schedule.

On February 18, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony of Dr. Casey A. Shull, Senior Utility Analyst in the OUCC's Electric Division, and Kaleb G. Lantrip, Utility Analyst in the OUCC's Electric Division. Hoosier Energy prefiled the direct testimony of Matt Mabrey, Vice President of Operations.

On February 25, 2022, Petitioner filed a second motion for protection of confidential and proprietary information that was preliminarily granted on March 4, 2022.

On March 4, 2022, Duke Energy Indiana filed the rebuttal testimony of Jeremy K. Lewis, Martin D. Dickey, and Maria T. Diaz.

An evidentiary hearing was held in this Cause commencing at 9:30 a.m. on March 24, 2022, in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of Duke Energy Indiana, the OUCC, and Hoosier Energy were admitted into the record without objection.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published as required by law. Duke Energy Indiana is a public utility as defined in Ind. Code §§ 8-1-2-1(a) and 8-1-39-4. Under Ind. Code ch. 8-1-39, the Commission has jurisdiction over a public utility's plan for eligible transmission, distribution, and storage system improvement charges ("TDSIC"), including TED projects. The Commission, therefore, has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Duke Energy Indiana is a public utility and wholly-owned subsidiary of Duke Energy Indiana Holdco, LLC, with its principal office located in Plainfield, Indiana. Petitioner is engaged in the business of rendering retail electric utility service and owns, operates, manages, and controls, among other things, plant, property, and equipment within Indiana used for the production, transmission, distribution, and furnishing of such service. Duke Energy Indiana provides electric service to approximately 860,000 customers in 69 Indiana counties. Petitioner also sells electric energy for resale to municipal utilities, Wabash Valley Power, Indiana Municipal Power Agency, and other electric utilities.

3. **Relief Requested in this Cause.** In accordance with Ind. Code § 8-1-39-10, Petitioner requests approval in this Cause of its TDSIC 2.0 Plan, as follows:

(a) a finding that the projects contained in the TDSIC 2.0 Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2;

(b) a finding that Petitioner included ~~of~~ the best estimate of the cost of the eligible improvements included in the TDSIC 2.0 Plan;

(c) a determination that the public convenience and necessity require or will require the eligible improvements included in TDSIC 2.0;

(d) a determination that the estimated costs of the eligible improvements included in TDSIC 2.0 are justified by incremental benefits attributable to the TDSIC 2.0 Plan;

(e) a determination that the TDSIC 2.0 Plan is reasonable and should be approved, and designating the eligible transmission, distribution and storage system improvements included in TDSIC 2.0 as eligible for transmission, distribution and storage system improvement charge treatment in accordance with Ind. Code § 8-1-39-9;

(f) authority to recovery 80% of the TDSIC 2.0 costs via Standard Contract Rider No. 65 ("TDSIC Rider"), and deferral with carrying costs of 20% of the TDSIC 2.0 costs for subsequent recovery in Petitioner's next general retail electric base rate case; and

(g) approval of Petitioner's proposed process for updating the TDSIC 2.0 Plan in future annual proceedings.

4. **Duke Energy Indiana's Case-In-Chief.**

A. **Mr. Pinegar.** Mr. Pinegar testified that although Petitioner's initial TDSIC plan targeted the replacement of aging infrastructure on the system, the priority of TDSIC 2.0 is to provide reliability benefits to customers, such as reduction of frequency and duration of interruptions, hardening and resiliency of the grid, and modernizing the grid to manage growing renewable, distributed generation on the system. He testified that Petitioner's commitment to customer value is evident in the rigorous cost to benefit analysis utilized to ensure selection of projects that provide optimal value for customers to improve the reliability, flexibility, and capacity of the grid to meet growing customer expectations, demands, and needs. Mr. Pinegar described today's customer expectations, stating that power quality and reliability are the top drivers, followed closely by price. He testified that, although Petitioner appreciates the investments provided in TDSIC 2.0 need to be undertaken, Petitioner is limiting the overall average annual rate impact to approximately 1%.

Mr. Pinegar testified that TDSIC 2.0 addresses the changing service expectations of Petitioner's commercial and industrial customers. In addition to reliable service, the proposed TDSIC 2.0 investments help facilitate the expansion of renewable and distributed generation for all customers. The TDSIC 2.0 Plan includes technology that improves reliability, increases power quality, and minimizes momentary outages. He testified that the various TED projects that may be executed during TDSIC 2.0 will provide adequate capacity and reliable service to attract companies looking to locate and expand in our state.

Mr. Pinegar testified that the objectives of the proposed TDSIC 2.0 Plan are to improve reliability for Indiana customers, advance grid hardening and resiliency, enable expansion of renewable and distributed generation, and facilitate economic development growth. With much of Duke Energy Indiana's system over 40 years old and the expansion of Distributed Energy Resources ("DER") and electrification trends, TDSIC 2.0 will ensure reliability and prepare the grid for the future. Measured investments will avoid future customer interruptions ("CI") and customer minutes interrupted ("CMI"). Mr. Pinegar testified Petitioner expects to show measurable improvement to reliability over the six-year period by measuring CI and CMI avoided, which after the successful implementation of TDSIC 2.0, will produce a minimum 19% improvement to System Average Interruption Duration Index ("SAIDI") and a minimum 17% improvement to System Average Interruption Frequency Index ("SAIFI"). To improve reliability, TDSIC 2.0 includes investments to advance hardening and resiliency of the transmission and distribution grid. He explained that hardening physically changes the infrastructure to make it less susceptible to damage, while resiliency makes the grid smarter and better able to recover from events more quickly. Proposed TDSIC 2.0 hardening programs include line rebuilds, pole upgrades and replacements, installation of intermediate dead-end structures, targeted underground, transformer replacements, and uprating 4kV lines to 12kV. Proposed TDSIC 2.0 resiliency programs include Self Optimizing Grid and Automated Lateral Device investments, and installation of Supervisory Control and Data Acquisition ("SCADA") to transmission switches and substations.

Mr. Pinegar testified that TDSIC 2.0 will facilitate increased distributed and renewable energy investments in the State by advancing a two-way smart-thinking grid networked to intelligently detect, rapidly react, and proactively adapt to changes in usage. It also enables customers to become active participants in the grid system by installing assets like rooftop solar and premise level storage.

Mr. Pinegar testified that Petitioner worked with the Indiana University Business Research Center ("IBRC') to perform an Economic Impact Study on the transmission and distribution projects within TDSIC 2.0, excluding the targeted economic impact projects. TDSIC 2.0 will bring economic benefit to Indiana by creating or supporting an estimated 1,270 jobs each year of the six-year TDSIC 2.0 Plan, with an expected average pay-range of $135,000. The TDSIC 2.0 investments will also produce an estimated $4.3 million in additional state and local tax revenue and $215 million in gross domestic product annually over the six-year period. Mr. Pinegar testified the TDSIC 2.0 Plan is reasonable and in the public interest.

B. **<u>Mr. Lewis</u>.** Mr. Lewis testified that TDSIC 2.0 is a six-year, $2.0 billion plan including an estimated $158 million of TED investments. Capital transmission investments total approximately $815 million, while distribution investments total $1 billion over the six years. TDSIC 2.0 is designed to achieve cost-effective improvements in grid reliability, safety, grid modernization, and economic development. He testified greater than 80% of the proposed TDSIC 2.0 programs will influence reliability through proactively reducing the frequency and duration of outages. Looking retroactively at Duke Energy Indiana's past five-year average, if the proposed TDSIC 2.0 investments were in place, he estimated approximately 23% of CI and 28% of CMI would have been avoided. He testified that TDSIC 2.0 programs will transform the system to a dynamic smart-thinking and self-healing grid that will quickly locate faults, reroute power around faults, and restore power more quickly to customers, thus avoiding CI and CMI both on Major Event Days ("MED") and non-MED. Variables outside of TDSIC projects, such as major storms, vegetation management, cellular advancement, and vehicle accidents, impact reliability measurements and project performance metrics, so it is important to measure the success of TDSIC 2.0 following the full execution of the investment plan.

Mr. Lewis testified that grid hardening physically improves the durability and stability of the energy infrastructure making the asset or grid stronger, while resiliency makes the grid smarter and better able to react to events. Although resiliency measures do not prevent damage, they enable grid systems to continue operating despite damage and/or promote a more rapid return to normal operations when damages or outages do occur. Mr. Lewis testified that 24 of the 35 sub-programs in TDSIC 2.0 contribute to resiliency and hardening of the grid. These sub-programs will help eliminate outdated grid architectures, target vulnerable assets with high consequence of failure, solve asset conditions that contribute to extending outages, and maintain or improve customer safety. Inspection-based programs will proactively replace grid hardware and equipment based on age, condition, and historical failure rates. TDSIC 2.0 is also designed to facilitate the expansion of renewables and distributed generation through building a self-optimizing grid, Integrated Volt-Var Control ("IVVC"), SCADA communication, substation relay replacements, circuit visibility and control, and circuit rebuilds.

Mr. Lewis testified that TDSIC 2.0 utilizes a targeted set of programs that advance the distribution system allowing the grid to adjust the power flow to self-heal when an event occurs, thus avoiding CI and CMI. These programs include Self Optimizing Grid ("SOG"), which will isolate faults on the backbones of circuits from approximately 1,000 customers per segment to 400 customers per segment, allowing service to be restored to other portions of the circuit; Targeted Underground ("TUG"), which places strategic infrastructure underground to eliminate the source of overhead outages; and Automated Lateral Device ("ALD"), which is targeted to the lateral lines of distribution systems to reclose on temporary faults and isolate those temporary faults to eliminate customer outages. These programs will improve the experience of Duke Energy Indiana's commercial and industrial customers with enhanced troubleshooting efficiencies to improve restoration times, fewer interruptions, and reduced outage durations. After the completion of TDSIC 2.0, the Company estimates the number of customers served by automated circuits to increase from 11% to over 65%. Mr. Lewis testified that TDSIC 2.0 also includes additional installation of technology with near real-time two-way data communication, data collection, and remote operations capability to pinpoint and isolate system trouble to restore service more quickly.

Mr. Lewis provided a TDSIC 2.0 Workplan summarizing the distribution projects, as well as cost details. He testified that the projects were selected based on a variety of engineering analyses and asset data aligning with the TDSIC 2.0 objectives and focused on their improvement to system integrity, reliability, and benefit to customers. A Class 5 estimate was assigned to each potential project and the initial list of investments was provided to Black & Veatch ("B&V") to run through the Investment Plan Analysis and scored through a cost to benefit ratio by substation. He testified that the investment plan in TDSIC 2.0 will be executed by substation and circuit to gain labor resource efficiencies. He testified that the Investment Plan Analysis is the accumulation of all Duke Energy, B&V, Copperleaf, value models, risk models, and optimization efforts together. Projects were identified by Duke Energy Indiana to address known conditions and performance issues on the system, which were then evaluated for consequence and likelihood of failure. Opportunities to improve these conditions and enhance functionality through proven automated technologies were also assimilated to put through the Investment Plan Analysis. He testified that leveraging system knowledge with the rigorous risk and value studies led to the selection of projects that provide the most benefit for the cost. In selecting the TDSIC 2.0 investments, approximately $1.7 billion of potential distribution investments were analyzed through the Investment Plan Analysis, which returned $775 million of select distribution investments. The Investment Plan Analysis used two funding mechanisms: "optimized" and a small amount of "reserved," which meant the subject matter experts held a portion of the funding specifically for these necessary sub-projects within Inspection Based, 4kV Conversion, Underground Cable Rehab, and Capacitor Automation. Funding levels for these projects were selected using historical analysis of performance, value, and necessity to the TDSIC objectives. All other projects were optimized in the model.

Mr. Lewis described the five distribution program categories within TDSIC 2.0 as follows:

(1) Circuit Backbone Uplift. Includes 8 sub-programs which target circuit enhancements to support circuit modernization, including automation, segmentation, and controlling circuit operations to enable self-optimization. These investments reduce outage impacts with respect to their occurrence frequency, grid impact footprint, recovery time, and cost, with the added value of improving capability to better integrate distributed energy resources on the grid.
(2) Overhead Lateral Uplift. Includes 4 sub-programs aimed at improving the lateral grid's reliability and resiliency. These projects add segmentation and automation of the circuit laterals to reduce the number of outages and customer impacted as well as reducing the duration of the outages.
(3) Underground System Uplift. Targets cable rehabilitation for improved reliability.
(4) 4kV Conversions. Consists of the conversion of risk-prone, legacy standard, and dated architecture of lower operating voltage lines to a 12kV system to address all three objectives of the Investment Plan.

(5) Inspection Based Programs. Includes 4 sub-programs and is a condition-based program geared towards proactively replacing grid hardware and equipment based on effective age and historical failure rates.

He provided an overview of the TDSIC 2.0 sub-programs, which are detailed in Petitioner's Exhibit 4-A (JWS), including those contributing to the enablement of expanding solar and renewables. Collectively, TDSIC 2.0 distribution capital investments leverage grid automation, data management and automated grid sensors, and communication and response capability to effectively integrate a greater proportion of renewable and distributed energy resources across the distribution network, while improving reliability, economic performance and customer choice. He testified that the TDSIC 2.0 distribution programs improve grid hardening, resiliency, and reliability throughout Duke Energy Indiana's service territory, benefiting all customers.

Mr. Lewis provided a detailed cost estimate for every project in the TDSIC 2.0 Investment Plan derived utilizing either engineered work, built up estimates, or parametric modeling, using the Association for the Advancement of Cost Engineering International ("AACE") standards and Duke Energy's Project Management Center of Excellence guidelines. Each TDSIC 2.0 project was estimated based on asset or compatible unit using historical values, subject matter expertise and reviewed by B&V. He testified that the majority of projects in years one and two achieved Class 2 status, with outer years at Class 3 or 4. A projected contingency amount of 15% was calculated using a Monte Carlo simulation, and added to the base cost estimate to cover estimate uncertainty and risk over the six-year TDSIC 2.0 Plan. Mr. Lewis testified that any direct project O&M expenses related to distribution capital projects, as well as vegetation removal necessary to perform the capital project construction, are included in the cost estimate. Mr. Lewis testified that B&V was brought in as a third party to evaluate and validate the transmission and distribution project selections, estimates, and economic impact, concluding that the TDSIC 2.0 Plan cost estimating was reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes.

Mr. Lewis testified that the TDSIC 2.0 Plan is expected to provide secondary benefits to the state by generating additional economic activity, which was assessed by the IBRC at Indiana University. The IBRC concluded the TDSIC 2.0 Plan, excluding TED and contingency, will contribute an estimated $1.04 billion in compensation in Indiana and approximately $1.29 billion in gross domestic product.

Mr. Lewis testified that Duke Energy Indiana proposes to update its TDSIC 2.0 Plan annually in the fall, with cost recovery filings in the spring. He explained that units in a project may be susceptible to change, especially in outer years, due to the most current evaluations of system needs. To provide flexibility to TDSIC 2.0 and mitigate the likelihood of change, similar to the TDSIC 1.0 Plan, Duke Energy Indiana requests the Commission designate the identified alternate list of projects as eligible projects so that in future TDSIC 2.0 rider filings, the Company has the option of moving projects on to and off of the alternate list and active plan as necessary for the greatest benefit to the system and its customers. He testified that the overall costs of TDSIC 2.0 would not be substantially changed by substituting these alternate plans. If the overall investment plan is tracking under its expected cost, it is prudent and beneficial to customers to insert projects off the alternate list into the active TDSIC 2.0 Plan to create additional customer value while staying under the overall cost estimate and within the 1% customer annual rate increase.

Mr. Lewis testified that Duke Energy Indiana is quantifying reliability performance through avoided CI and CMI, estimating an 80% probability of avoiding between 22 and 45 million CMI and between 149,000 and 249,000 CI upon the conclusion of the TDSIC 2.0 investments. Based on a historical five-year average, this is expected to produce a minimum 19% improvement to SAIDI and 17% improvement to SAIFI. The 80% probability factor is based on variables outside of TDSIC 2.0. He testified regarding Duke Energy Indiana's commitment to tracking CI/CMI of the self-optimizing grid based on its automation savings and contribution to SAIDI/SAIFI and proposed tracking progress by reviewing total savings by annum for minimum and maximum CI/CMI, inclusive of the target, and the impact of MEDs and non-MEDs. To develop the quantitative customer benefits, most recent complete five-year historical reliability data in conjunction with the TDSIC 2.0 program scope was checked against similar work in other jurisdictions. Those effects are then calculated on the expected future reliability performance of the Indiana system. He testified that an additional benefit from the TDSIC 2.0 Plan is the Value of Lost Load calculated by B&V utilizing the Department of Energy Interruption Cost Estimator ("ICE").

Mr. Lewis testified that Duke Energy Indiana has a multitude of annual transmission and distribution projects that are not included in TDSIC 2.0. The approach for identifying assets for replacement in the TDSIC 2.0 Plan is the result of the rigorous Investment Plan Analysis, particularly the new methodology of evaluating projects methodically, with benefit to cost ratio. He testified that there are no duplicative items in the TDSIC 2.0 Plan. Duke Energy Indiana has provided the best estimate of the costs of the eligible improvements within TDSIC 2.0, and public convenience and necessity require each component of TDSIC 2.0. The TDSIC 2.0 Plan is reasonable, necessary, and justified by significant reliability, hardening and resiliency, and modernization benefits.

C. <u>Mr. Dickey</u>. Mr. Dickey described the two main categories of transmission programs in TDSIC 2.0 – Line Hardening and Resiliency, and Substation Hardening and Resiliency, which focus on hardening the grid by preventing events from adversely affecting system operation and enhancing system resiliency through technology designed to isolate faults by automated remote devices that reconfigure the system to reduce and shorten customer outages. He testified that the benefits from the distribution investments are complemented by benefits received from the transmission portion of TDSIC 2.0, with an overall benefit to cost ratio of 3.5 and overall program value of $2.8 billion for the $800 million core transmission project planned investment. This means for every dollar spent on the TDSIC 2.0 Plan, Indiana customers should receive a payback of $3.50 in primary benefits. Implementation of these projects will result in risk reduction, avoided customer outages, avoided loss of system redundancy, and power quality improvements.

Mr. Dickey provided examples of the TDSIC 2.0 sub-programs designed to improve the hardening of the grid, including wood to non-wood structure replacements, wood cross arm replacements, transmission line rebuilds, installation of intermediate dead-end structures to mitigate cascading events, and replacing deteriorated and obsolete equipment prone to catastrophic failures. Examples of TDSIC 2.0 sub-programs designed to improve resiliency of the grid include looping short radials through existing substations, adding Supervisory Control and Data Acquisition ("SCADA") functionality to substations, adding SCADA to switches, and transmission relay upgrades at substations. The SCADA switch sub-program will increase the number of remote-controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults. Mr. Dickey testified that the TDSIC 2.0 upgrades to the 68kV transmission system will increase continuity of service and improve power quality and reliability for many industrial and wholesale customers. The hardening and resiliency of the Bulk Electric System ("BES"), which are assets 100kV and above, is a critical component to reliable service. Although the BES does not directly impact CI/CMI avoided, it is the link between generation facilities to the 69kV system and distribution system that ultimately serves customers' homes and businesses. He testified that while BES is redundant in design, increased age, deterioration, and obsolescence of equipment requires increased investment to avoid disruption to power flows and customer interruptions. Mr. Dickey testified that power quality issues, such as momentary interruptions and voltage sags, can result in loss of revenue and productivity for industrial customers. The Transmission Line and Substation Hardening and Resiliency programs reduce the risk of momentary and sustained outages during an in-service failure that can yield productivity and financial gains for many large industrial customers. He testified that there are TDSIC 2.0 substation projects that support IVVC and increase the ability of the Distribution System Operators to remotely monitor and control the voltage level the substations supply to the distribution circuits. Upgrades to control capability and added voltage regulation equipment are included in TDSIC 2.0.

Mr. Dickey provided cost estimates for each transmission line and substation project in TDSIC 2.0 and explained how the estimates were developed. He testified that using site reviews conducted by Duke Energy and Burns & McDonell (consulting engineer subject matter experts), an asset-specific project scope was developed to calculate AACE Class 4 estimates. The Class 4 estimates were created by using averages of recently bid capital projects, then applying those averages and unit costs to the TDSIC 2.0 project work scopes. He testified that as projects approach their targeted in-service year, typically two years prior to construction, an AACE Class 3 estimate will be prepared. In the case of TDSIC 2.0 transmission, there are no Class 3 estimates utilized. Rather, to provide the best estimate, Class 2 estimates have been prepared for projects up to three years prior to construction and for the first two years of the transmission program (2023 and 2024). Mr. Dickey testified that the cost estimates include project-related O&M incurred during the construction of the capital projects. In addition, contingency is added to the base cost estimates of the project categories to cover estimate uncertainty and risk, per AACE guidelines.

D. <u>Mr. Shields</u>. Mr. Shields testified that B&V was engaged by Duke Energy Indiana to identify transmission and distribution ("T&D") system improvements and asset replacements that produce the greatest benefits to customers. For its investment plan analysis, B&V combined Copperleaf's decision analytics tool for quantifying benefits and optimizing investments with a Risk Adjusted Project Prioritization ("RAPP") modeling tool to identify high risk assets. Although Duke Energy Indiana determined the objectives of the TDSIC Plan, collaboration with B&V identified the programs to support those objectives. Mr. Shields explained how the benefit categories were identified and mapped to a value model within Copperleaf to calculate net benefits for each project. Optimizing investments helped ensure high value projects were located in the areas on the system that produced the greatest value. Constraints were applied at the sub-program level to determine TDSIC 2.0 projects. Mr. Shields described Copperleaf as a decision analytics software tool used to quantify benefits associated with critical infrastructure investments. Value models were developed for each investment type with specific value measures that quantify the benefits of the investments. Once the cost of each investment was paired with the benefits, the Copperleaf tool ran various investment scenarios to produce an optimized investment plan. He testified that the RAPP tool was used to compliment Copperleaf by identifying high risk assets. RAPP calculated risk scores for assets included in the asset risk register, with risk defined as the product of Probability of Failure ("PoF") multiplied by the Consequence of Failure ("CoF"). The actual age of assets was adjusted to an effective age using survivor curves and asset health data, from which a probability failure was then calculated. CoF was calculated from a criterion of consequences and scored based on the criticality of the consequence. The RAPP identified high risk assets that were input into Copperleaf to compete for funding with other projects identified in the development of the TDSIC 2.0 Plan.

Mr. Shields described the value model concept which combines all the benefits a project produces and calculates the value measure (financial and non-financial benefits produced) to quantify the net benefits of the project. The value measures used in development of TDSIC 2.0 were risk mitigation, benefits, and cost. For risk mitigation value measure, used to capture the value of avoiding undesirable outcomes, a uniform risk matrix was developed to align the mitigation of risk to a common scale. Mr. Shields provided the probability levels used in calculating risk mitigation value units, as well as how the thirteen quantifiable benefit categories were mapped to sub-programs that produced the benefit. Value models in Copperleaf combined all the value measures a project could produce to calculate the net value of the project. From this portfolio of investments, an optimization analysis was performed to direct the funding of projects using reserved and optimized funding methods. He testified that the optimization approach used directed funding based on highest benefits generated, to specific areas on the system. Funding levels were set by Duke Energy Indiana and applied in the TDSIC 2.0 Plan development. Mr. Shields testified that in general, the same methodology was used to evaluate both transmission and distribution projects. However, benefits were assessed slightly differently due to transmission systems being designed for redundancy to minimize impacts on large numbers of customers and to transport power long distances reliably. Therefore, benefits on the transmission system were focused less on the value of loss load and more on maintaining and reinforcing the redundancy that currently exists. Distribution substation and line project benefits were valued based on the reduction in future outages compared to historical system performance. Mr. Shields summarized the CMI and CI distribution program improvements as a result of the TDSIC 2.0 Plan. He testified that the TDSIC 2.0 Plan has a 2.8 benefit to cost ratio, showing the estimated cost of the TDSIC 2.0 Plan is justified by the incremental benefits attributable to the TDSIC 2.0 Plan.

Mr. Shields testified that B&V validated Duke Energy Indiana's cost estimates using the AACE classification system and by performing independent estimate reviews for other TDSIC filings in Indiana. The estimate sample included both AACE Class 2 and Class 4 type estimates used in the TDSIC 2.0 Plan. The estimates were reviewed with line item material and labor estimates including quantities needed for the specific projects. He testified that Duke Energy Indiana's assumptions and methodology used to develop the estimates were reasonable.

E. <u>Ms. Schneider</u>. Ms. Schneider testified regarding Duke Energy Indiana's request for approval of the River Ridge Project as a TED project for inclusion and associated cost recovery in TDSIC 2.0. Ms. Schneider testified that Duke Energy Indiana is working with more than ten industrial and commercial customers seeking sites for new facilities at River Ridge Commerce Center, a business and manufacturing park with over 6,000 prime acres of land under development. Petitioner currently has insufficient capacity to support the estimated 500+ MW load for these project commitments. Petitioner's River Ridge Project proposes to invest additional infrastructure at the site to increase capacity on Duke Energy Indiana's system and continue business investment at River Ridge.

Ms. Schneider testified that current projections estimate the River Ridge Project could create more than 8,000 jobs and bring about $3 billion in capital investment. The associated wages from those jobs will positively impact the region, and the capital investment will increase the tax base and overall economy within the region and State of Indiana. She testified that any potential investment at River Ridge would likely come in under Petitioner's existing economic development tariff (Rider 58) or a special contract with similar conditions. Ms. Schneider explained that proactively building the transmission infrastructure to increase capacity at River Ridge will attract more economic development and capital investment to the area, which aligns with the Indiana Economic Development Commission's (IEDC) mission to attract and support new business investment, create new jobs for Hoosiers, and further Indiana's legacy as one of the top states in the nation for business. It also allows Duke Energy Indiana to work with community partners, such as One Southern Indiana to achieve their goals to enhance the area's vibrancy by facilitating economic transactions that generate wealth and add to community prosperity as depicted in its letter of support included as Petitioner's Exhibit 5-B.

Ms. Schneider testified that under the River Ridge Project, Petitioner plans to install 138kV 6-position, 4-breaker ring bus, which will allow future isolation of the substation for outage-free maintenance. Petitioner proposes to loop In/Out existing 138kV line 13857, which will increase reliability by adding a substation to shorten a longer circuit into two shorter circuits. She testified that Petitioner will be constructing the "high side" or the transmission side of the substation only, maintaining close proximity to the existing 138kV line. An initial yard will be constructed for the substation sized to accommodate a variety of customer-specific scenarios for the "low side" or distribution side of the substation. Ms. Schneider testified that the estimated cost of the River Ridge Project is $44 million. TED treatment of the River Ridge Project allows Petitioner to make the necessary investments to extend required services of existing customers and provide an additional

200 MW of capacity to serve additional customers. She testified that Petitioner sent a letter to IEDC for approval to treat the costs associated with the proposed River Ridge Project as TDSIC costs, in compliance with GAO 2016-6.

Ms. Schneider described the potential for additional TED projects throughout Petitioner's six-year TDSIC 2.0 Plan period. Updated information regarding the scope, timing and cost of any additional TED projects will be included in Petitioner's semi-annual TDSIC Rider and update filings.

F. **Ms. Diaz**. Ms. Diaz testified that this proceeding was filed more than nine months after Petitioner's last retail electric base rate case order in Cause No. 45253, and the proposed TDSIC 2.0 investments are not included in its rate base. She confirmed Petitioner's intention to file for a change in basic rates and charges before the expiration of TDSIC 2.0. Revised rate schedules resetting the TDSIC Rider charge will be filed once new basic rates and charges that include TDSIC 2.0 investments become effective.

Ms. Diaz testified that Petitioner is requesting authority to recover 80% of the retail jurisdictional share of TDSIC 2.0 costs through the existing Rider 65, pursuant to Indiana Code § 8-1-39-9(a). The statutory recoverable TDSIC costs include depreciation, O&M, property taxes and pretax return on eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post-in-service, as well as costs associated with an approved economic development project. Petitioner requests authority to accrue post-in-service carrying costs until the costs related to TDSIC 2.0 are included in retail rates, with the accrual at rates equal to Petitioner's overall weighted average cost of capital most recently approved by the Commission. She testified that Petitioner will include in TDSIC 2.0 expenditures for projects that are in-service at the time of the annual cut-off dates. She testified that post-in-service carrying costs accrued on TDSIC costs, including both debt and equity financing, will be accrued on approved capital expenditures, including accrual on previously computed post-in-service carrying cost amounts, from the in-service date until such costs are included in rates under Rider 65 or in base rates.

Ms. Diaz testified that Petitioner proposes to defer the remaining 20% of the retail jurisdictional portion TDSIC 2.0 costs until its next general retail electric base rate case. Pursuant to Ind Code 8-1-39-9(c), Petitioner requests approval to defer for subsequent recovery the retail jurisdictional portion of the remaining 20% of approved expenditures, allowance for funds used during construction ("AFUDC"), post-in-service carrying costs, O&M expense, property taxes, and depreciation expense using a regulatory asset account (FERC CFR Account 182.3) until such costs are fully reflected in Duke Energy Indiana's retail base rates after a general retail electric base rate case. Petitioner also requests carrying costs on the deferred costs be accrued using Duke Energy Indiana's overall weighted average cost of capital as most recently approved by the Commission. Ms. Diaz testified that AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates or when the projects are placed in service. She testified that the deferral of TDSIC 2.0 costs will be from the in-service date until the cost is included in Petitioner's rates under Rider 65 or in base rates.

Ms. Diaz testified that Petitioner will consider both the FERC accounting and whether the function is a transmission or distribution service when including investments in the TDSIC Rider and will not limit the included costs to specific FERC accounts. She testified that the rates used for depreciation expense are the weighted average depreciation rates approved in Petitioner's most recent retail base rate case in Cause No. 45253 by the transmission and distribution plant groupings. Petitioner proposes to net depreciation expense on retired plant against depreciation on new plant included in the TDSIC Rider. She testified that Petitioner has estimated and included depreciation expense reductions for retirements in this plan filing so as to not recover new and replacement project depreciation expense on both the additions and the retired asset. Petitioner will present the actual calculations supporting the reductions for the depreciation expense credits in the first tracker filing. Ms. Diaz testified that the proposed deferred accounting treatment is in accordance with U.S. Generally Accepted Accounting Principles (GAAP) and is appropriate from both a ratemaking and an accounting perspective.

Ms. Diaz testified that there are no proposed changes to the existing TDSIC Rider. The TDSIC Rider will recover 80% of the retail jurisdictional portion of the costs associated with TDSIC 2.0 projects, including financing costs, O&M directly associated with the construction of the project, depreciation, property taxes, and other Commission approved costs in the establishment of the revenue requirements. She testified that the components of the revenue requirement, which includes targeted economic development projects for TDSIC 2.0, are multiplied by revenue conversion factors to establish the total revenue requirement for the TDSIC Rider. Petitioner proposes to use the 9.70% current return on common equity approved in Cause No. 45253 in the development of Rider 65 for TDSIC 2.0. The capital structure would be updated with each TDSIC 2.0 filing, along with the debt costs. Ms. Diaz the rate impact estimates for TDSIC 2.0 reflect 100% allocation to retail, with allocation of the transmission and distribution revenue requirement for Rider 65 based on the revenue requirement by rate group approved in Cause No. 45253. Costs will be billed to individual customers within a rate group based on kWh sales, except customer served under Rate HLF which will be recovered based on non-coincident kW demands. Ms. Diaz testified that the fuel clause return test will be adjusted with the incremental net operating income from Rider 65. Ms. Diaz testified that the TDSIC Rider will continue to be implemented using forecasted amounts for O&M, depreciation, and property taxes based on annual cut-off dates. Financing costs on invested capital will be on an actual basis based on annual cut-off dates used for in-service capital projects. In subsequent Rider filings, Petitioner will true-up amounts to actual levels of O&M, depreciation, and property taxes and to actual kWh sales levels.

Ms. Diaz proposed a timeline for the TDSIC 2.0 Rider 65 filings, with the first filing to occur in the April 2024 timeframe with a projected effective date of approximately October 2024. The April filing would seek recovery of capital expenditures and costs as of December 2023 and estimated O&M, property taxes, and depreciation expense for the following 12-month period of October 2024 through September 2025. Going forward, Petitioner would continue to file the TDSIC Rider each April, with a reconciliation included in subsequent Rider 65 filings.

Ms. Diaz testified that Petitioner is proposing to recover its expenses incurred for retaining B&V. Similar to the current TDSIC 1.0 plan, Ms. Diaz proposed to amortize all B&V costs over a three-year period.

Ms. Diaz testified that the total annual average retail rate impact of TDSIC 2.0 compared to prior year retail revenue is estimated to be slightly less than 1% over the recovery periods. She testified Rider 65 filings will include the actual proposed revenue increase compared to the total retail revenues at the time. Should an actual total amount exceed the 2% annual total statutory cap, Petitioner requests approval to defer recovery of the TDSIC costs above the cap, pursuant to Ind. Code 8-1-39-14(b).

5. OUCC's Direct Evidence.

A. Dr. Shull. Dr. Shull testified it is impossible to verify whether B&V's Copperleaf modeling logic is reasonable or accurate because of it~~ i~~s proprietary status. B&V relied upon spreadsheet values from Petitioner as inputs into its proprietary modeling algorithms to produce outputs to categorize projects into value measures used to optimize and select projects for inclusion in TDSIC 2.0. Dr. Shull testified ~~that~~ he identified a miscalculation in the average number of outages used as an input for Value of Lost Load ("VOLL") provided by Duke Energy Indiana to B&V, and that Petitioner was unable to explain the miscalculation. He testified ~~that~~ this fact calls into question the validity of the VOLL values used to produce TDSIC 2.0.

Dr. Shull testified the proposed TDSIC 2.0 Plan includes increasing redundancy through rehabilitation of electrical transmission, substations, and distribution facilities. He defined redundancy as the ability for a system to have alternate methods of delivering a specific service to its customers during adverse conditions. He testified Petitioner failed to provide empirical evidence or support explaining why the public convenience and necessity require the replacement or rehabilitation of these proposed redundancy projects. He testified Petitioner claims its system is already highly redundant and ~~reliable, and~~reliable and has provided no support for an added layer of redundancy. Dr. Shull identified nineteen transmission line projects he recommended be removed from TDSIC 2.0, stating ~~that~~ the projects do not qualify as system modernization, have not been shown to require replacement due to deterioration, and do not result in a reduction of CI or CMI or improved reliability. Dr. Shull testified the proposed TDSIC 2.0 Plan anticipates a 0.21% decrease in SAIFI. Therefore, ~~T~~the incremental benefit these projects may provide does not justify the $800 million cost and is not for purposes of safety, reliability or modernization.

Dr. Shull testified that adding electrical system devices in TDSIC 2.0 will not necessarily provide the capability and/or market for future Distributed Energy Resources ("DER") installations. He testified Petitioner has not demonstrated a customer demand for DER, and it would be prudent for Duke Energy Indiana to wait and build its system specific to meet its customers' DER needs. Given these projects are unnecessary and outside the scope of the TDSIC statute, they would not meet the obligation of "protecting affordability~~.~~" as stated in Ind. Code § 8-1-2-0.5.

Dr. Shull testified ~~that~~ Petitioner's cost-benefit assessment does not take into consideration the unstable aluminum, copper, and steel commodity prices. Therefore, the TDSIC 2.0 cost estimates are understated, resulting in an overstated incremental benefit calculation.

Dr. Shull recommended Duke Energy Indiana's TDSIC 2.0 Plan be denied. He testified Petitioner has not provided all data it used to develop TDSIC 2.0 and relies on flawed data and methodologies ~~which~~that cannot be replicated to determine the accuracy of the cost-benefit analysis. Dr. Shull testified ~~that~~ Petitioner has failed to demonstrate public convenience and necessity requires upgrades for future DER or renewable projects not yet identified. He testified further that Petitioner has not presented the "best estimate of the cost," as it does not accurately reflect the rising commodity prices. Dr. Shull also testified ~~that~~ if TDSIC 2.0 is approved, the nineteen transmission line projects identified as being conducted for redundancy, as well as all DER-related projects, should be removed. He also recommended Petitioner provide biannual reports containing Project Management Institute ("PMI") EVM metrics.

B. Mr. Lantrip. Mr. Lantrip testified the OUCC has concerns about the affordability of TDSIC 2.0 and its impact on ratepayers. Mr. Lantrip testified that the Indiana General Assembly declared a policy to protect the affordability of utility services for present and future generations of Indiana citizens through Indiana Code 8-1-2-0.5 when utilities invest in infrastructure necessary for system operation and maintenance. Mr. Lantrip explained that DEI's two billion dollars it is requesting for TDSIC projects includes $837 million in total estimated revenue requirement over the TDSIC 2.0 Project's six-year plan. Mr. Lantrip noted that the TDSIC tracker is one of nine trackers Petitioner uses to periodically adjust customer rates. Mr. Lantrip noted that Petitioner's base rate case in Cause No. 42359, order date May 18, 2004, established a $72.11 monthly residential charge for a customer using 1,000 kWh. This rate was in effect until new rates were established in Cause No. 45253, order dated June 29, 2020. The monthly increase of approximately $51 (71%) was attributed to the Company's various trackers implemented between 2004 and 2019 with no full rate review of other costs or other economic considerations.

-Mr. Lantrip testified that in light of the Indiana General Assembly's stated policy, affordability should be a constant consideration for all Indiana jurisdictional utilities, as well as the Commission as it deliberates its decisions. ~~Cost recovery trackers outside base rates for many types of utility investments has led to a sequence of electric rate increases for Duke Energy Indiana customers. Affordability should be a constant consideration.~~ Although safe and reliable utility systems are extremely important, customers are faced with increasing utility costs while contending with hardships worsened during the COVID-19 pandemic. Mr. Lantrip~~He~~ testified the Commission should only approve necessary and reasonable requests from Petitioner to provide service at reasonable prices and take steps to moderate the imposition of higher rates over time.

Mr. Lantrip disagrees with Petitioner's assertion that post-in-service carrying charges ("PISCC") should be calculated at the weighted average cost of capital ("WACC") rate that includes both debt and equity in the carrying charge. He testified that traditionally, post-in-service charges on construction projects have been approved using the current Allowance for Funds Used During Construction ("AFUDC") rate of the utility, not the WACC. Mr. Lantrip testified that

Petitioner's proposal to include both debt and equity cost rates for post-in-service deferral is contrary to GAAP. The interest expense related to the debt portion of the PISCC calculation is the only cost that would be charged to expense. The equity portion of PISCC does not get charged to expense and therefore is normally not included in the deferral of post-in-service AFUDC. He testified that the Commission has allowed the equity rate of a carrying charge to be deferred post-in-service in prior cases, including TDSIC cases. Mr. Lantrip testified Petitioner's proposal for deferral treatment of the equity portion allows recovery of more dollars from ratepayers than Petitioner is permitted to record on its income statement. If approved, Petitioner would book a deferred asset for the amount until it is recovered later in a future rate proceeding. Mr. Lantrip testified that the Commission does not have to permit the deferral of the equity portion for future recovery because it does not impact the current financial statements. Unlike debt cost, post-in-service deferral of equity does not improve earnings erosion because GAAP does not permit it to be included on the income statement. He testified that Petitioner has not provided any evidence that it would be in financial distress without the additional deferral of equity.

Mr. Lantrip testified that the OUCC agrees with Petitioner's proposal to recover TDSIC 2.0 expenditures for projects that are in-service at the time of the annual cut-off dates, which is consistent with the methodology in Petitioner's current TDSIC 1.0 Plan. Mr. Lantrip recommended the Commission deny Petitioner's request for recovery of TDSIC 2.0 operation and maintenance ("O&M") expenses as the existence of O&M costs over and above what are currently being recovered through the Rider 65 and in base rates is unsubstantiated. However, if the Commission grants Petitioner's request, Mr. Lantrip recommended that Petitioner should demonstrate that the O&M costs are not duplicative of O&M Petitioner has already received through its general rate case allowance for costs of operation. He testified that improved and replaced assets should, if any change, spur a lower threshold requirement for ongoing O&M costs.

Mr. Lantrip testified the OUCC supports Petitioner's proposal to reconcile forecasted depreciation offsets for retired assets against actual retirements, which benefits ratepayers. He testified that although Petitioner has agreed to recognize the reduction of depreciation expense from the retirement replacement of TDSIC investment embedded in base rates, it has not reduced revenue requirement for embedded net book value of the replaced TDSIC investment used to calculate a return "on" those investments. As a result, Mr. Lantrip testified that Duke Energy Indiana's rates are higher and less affordable than they should be. He testified that reducing revenue requirement for replaced TDSIC investments does reduce timely recovery on the new TDSIC investments. However, it would reduce the overall increase to customers and improve affordability of Duke Energy Indiana's rates. Mr. Lantrip testified that although the TDSIC statute does not specifically prevent the recognition of ratemaking treatment on replaced investments that are still included in base rates, it does not prevent the reality that an excess recovery does occur.

Mr. Lantrip testified, if Petitioner's TDSIC 2.0 Plan is approved, the OUCC recommends (1) the Commission consider~~ing~~ the overall affordability of TDSIC 2.0 pursuant to Ind. Code § 8-1-2-0.5; (2) approval of Petitioner's proposed treatment to recover investments in-service as of cut-off date; (3) removal of the equity component from Petitioner's proposal for PISCC treatment to accrue both debt and equity financing on approved capital expenditures from the in-service date until such costs are included in Duke Energy Indiana's rates through Rider 65 or in base rates; (4) limiting recovery of O&M expense to the amount justified by Petitioner as incremental expense above and beyond what was approved in its base rate case, Cause No. 45253; (5) approval of Petitioner's proposal to offset to depreciation expense through a rolling 5-year FERC Form 1 estimated retirement ratio and later reconciliation to actual retirements; and (6) requiring Petitioner to recognize an offset in its revenue requirement for the return earned on the embedded net book value of retired assets which are no longer used and useful.

6. Hoosier Energy Direct Evidence. Mr. Mabrey testified Hoosier Energy interconnects with Duke Energy Indiana transmission lines at numerous locations throughout central and southern Indiana pursuant to interconnection agreements. Hoosier Energy serves approximately 51% of its member load off of Duke Energy Indiana owned transmission lines and 15% from Duke Energy Indiana substations. He testified Hoosier Energy has over 350 wholesale delivery points serving 18 distribution cooperatives, which in turn provide electric service to approximately 300,000 retail customers. Increased investment in targeted areas of the transmission system will reduce the number and duration of outages, thus improving overall reliability to Hoosier Energy member systems and their member consumers. Mr. Mabrey testified Hoosier Energy has made investments in the transmission system consistent with Duke Energy Indiana's TDSIC 2.0 Plan to improve reliability, address aging infrastructure, and accommodate additional load growth. He testified Hoosier Energy has worked with Duke Energy Indiana to identify specific transmission and substation upgrades that will impact its members. Investment in reliability, grid hardening and resiliency will greatly help Hoosier Energy and its members by providing more reliable service to its retail customers. Mr. Mabrey testified Duke Energy Indiana's proposed six year TDSIC 2.0 Plan provides a reasonable method of providing such upgrades and improvements.

7. Duke Energy Indiana's Rebuttal Evidence. Mr. Lewis submitted rebutt~~ed~~al testimony to Dr. Shull's testimony that Petitioner did not provide all data used to develop the TDSIC 2.0 Plan and that the proprietary Copperleaf modeling logic is unverifiable. He testified that, in addition to the detailed testimony, exhibits, and workpapers filed in this Cause, Petitioner also provided the inputs to the Copperleaf model and arranged two tech-to-tech meetings with the OUCC. Although the Copperleaf model itself is proprietary, the important components to understanding it are the inputs, which were developed by Duke Energy Indiana, provided to B&V, and produced to the OUCC in discovery. Mr. Lewis testified the Copperleaf model was used to optimize the TDSIC 2.0 Plan and is a decision analytics software used for critical infrastructure investment planning across the industry. Mr. Lewis testified that the data provided to B&V was neither "flawed" nor "miscalculated," as Dr. Shull claimed. The functionality underlying the formula calculations required to interpret the data was reviewed and explained to the OUCC. Specifically, the input workbook used the "vlookup" formula to obtain data on related tabs.

In rebuttal, Mr. Lewis testified that Duke Energy Indiana believes it is imperative that Petitioner plan for a future with expanded DER presence. Steadily increasing demand for DER is an ongoing trend in the industry. Petitioner's annual Generation Interconnection Reports submitted to the Commission demonstrate this ongoing increase in the number of DER on Duke Energy

Indiana's system, increasing from 43 applications in 2011 to 493 in 2021. He testified that waiting and attempting to design a system around already installed DER is not an effective or efficient way to plan for what is known to be coming, and could delay customer installations and reduce economic development opportunities for Indiana communities. Accommodating two-way power flow capability is needed now to manage and accept customer-generated and stored energy resources, such as wind, solar, and battery storage from customer-owned systems. He testified that Dr. Shull's reactive approach to DER integration on the Duke Energy Indiana system would potentially lead to unacceptable delays for customers with DER (*i.e.* rooftop solar) being able to connect to the grid and sell excess power. Upgrades in distribution capacity (*i.e.* reconductoring projects, new circuits, new substations, etc.) and the ability to handle two-way power flow (*i.e.* SOG, IVVC, etc.) are projects that can take a long time to complete which makes a reactive approach unacceptable from a customer service perspective. He testified the proposed investments related to DER benefit all Duke Energy Indiana customers by reducing outage impacts with respect to frequency, grid impact, recovery time, and cost. Improving system capability to enable DER was not an optimization criterion used in B&V's Cost Benefit Analysis, rather these projects were selected due to their reliability benefits and value to the T&D system as a whole.

Mr. Lewis testified that the TDSIC 2.0 cost estimates are not understated, as suggested by Dr. Shull. Duke Energy Indiana's supply chain organization, in collaboration with PowerAdvocate, evaluated historical component and commodity costs, as well as forecasts of these costs through the duration of TDSIC 2.0. The TDSIC 2.0 cost estimates are built from Class 2 estimates, using rates and estimates obtained mid-2021. Mr. Lewis testified that using 2021 estimates as a baseline, the costs for material, labor, and indirect costs for all projects were escalated at the rate of 3% per year until an individual project's in-service year is reached, through 2028 in some cases. The 3% escalation value was derived from the collaborative mid-2021 study performed by Duke Energy Indiana and PowerAdvocate, which has global industry expertise. Prices increase sharply in the latter half of 2020 and continue to increase until early 2022, in response to the global pandemic and supply chain issues presently impacting all areas of our economy. The projection then shows a general decrease in commodity and utility component costs through 2025, and finally a return to a typical aggregate 3% escalation rate in the outer years of 2026-2028. Petitioner used PowerAdvocate's forecast to develop a reasonable escalation rate for TDSIC 2.0. Mr. Lewis testified that although no one can know with certainty what prices will be in the future, Duke Energy Indiana reasonably assessed the possible range of commodity and component costs to provide a realistic escalation rate for TDSIC 2.0.

Mr. Lewis described the management structure for the TDSIC 2.0 Plan, which is the same as described in Petitioner's TDSIC 1.0 filings. Duke Energy Indiana uses AACE standards and its own Project Management Center of Excellence guidelines, which are consistent with PMI's *A Guide to the Project Manager Body of Knowledge* and the Project Management Professional Certification. Mr. Lewis testified that, similar to TDSIC 1.0, Petitioner will provide annual plan updates upon approval of TDSIC 2.0. The annual updates will include updated project estimates and variances to prior plan estimates, as well as movement of projects between years.

In rebuttal, Mr. Dickey testified that the BES is designed to be highly redundant in order to maintain reliability for all downstream customers served by those transmission lines. BES is subjected to North American Electric Reliability Council's (NERC) mandatory reliability standards, which require sufficient redundancy. He explained that the level of redundancy in the 69kV portion of the transmission system is different from the BES. Mr. Dickey testified that the increased resiliency by the addition of redundant capabilities in TDSIC 2.0 is not referring to building additional redundancy into the BES nor a large-scale redesign of the 69kV transmission system. Rather, these targeted projects within TDSIC 2.0 address specific existing single point of failure vulnerabilities. Several of these projects slightly change the line route to loop through the substation so there is no portion of the transmission line that would prevent restoring power to the substation. This allows the transmission line to be sectionalized by operating switches to isolate faults and restore electric supply to the substation in the event of a line outage. These switches can also be equipped with remote monitoring and control. He testified that these targeted investments are intended to improve reliability and do not create unnecessary or wasteful redundancy. The ability to sectionalize the transmission line and restore power to the substation reduces outage durations to the amount of time required to perform the switching. The TDSIC 2.0 transmission projects will reduce transmission line outages and retail and wholesale customer minutes interrupted ("Grid CMI").

Mr. Dickey testified that the 69kV transmission projects Dr. Shull recommends removed from TDSIC 2.0 are projects to rebuild aged and deteriorated sections of circuits or replace and upgrade specific switches located within other segments of the circuits. These circuits directly supply 25 Duke Energy Indiana substations and 11 substations owned by others. These specific circuits were selected based on a number of factors, including the longer-term history of outages, assessed age and condition of the poles and other equipment, outdated circuit design, and other prioritizing factors. These rebuild projects were, for all but one of these circuits, included in TDSIC 1.0, and the projects included in TDSIC 2.0 continue the longer-term effort to address remaining sections of these lines. He testified that these circuits were selected as being among the highest outage concerns, with a total of 273 outages resulting in 11.78 million Grid CMI from 2015-2021. TDSIC 2.0 will continue to reduce the number of outages on these circuits. Mr. Dickey testified that Duke Energy Indiana has evaluated and selected each of these transmission line rebuild projects to improve reliability by reducing the risk of outages from aged and deteriorated line equipment and performing these projects is in the best interest of Duke Energy Indiana's customers. Each of the projects included in TDSIC 2.0 were evaluated within the model and study performed by B&V and showed a strong reliability improvement due to reduced quantity and duration of outages. He testified that the evaluated reliability benefit justifies and validates the public convenience and necessity of these projects. In addition, these circuit rebuilds will provide a capacity increase between approximately 27% and 123%, due to the larger conductor size. The rebuilt lines will also upgrade and modernize the line by installing optical groundwire as the static shield wire, which includes fiberoptic communications fibers to allow digital telecommunications from one end of the circuit to the other. Mr. Dickey testified that the transmission line rebuild projects that Dr. Shull recommended for removal from TDSIC 2.0 had a condition-based recommendation for pole replacement rate that was two times higher (8%) than the average of Duke Energy's transmission system overall. In addition, although not expressed directly as CI or

CMI reduction, the B&V model used to evaluate and prioritize projects for inclusion in TDSIC 2.0 showed these projects to have significant reliability benefits, averaging 4.1 times the cost of the projects. Mr. Dickey testified that transmission line outages can result in more CMI than distribution outages and TDSIC 2.0 helps mitigate CMI associated with those outages.

In rebuttal, Ms. Diaz testified that the 2% rate impact limit included in the TDSIC statute protects customers from rate impacts associated with TDSIC investments and safeguards affordability. Under the TDSIC statute, utilities must petition for a retail rate case before the expiration of the TDSIC plan life. Therefore, a full review of Duke Energy Indiana's basic rates and charges will occur in conjunction with TDSIC 2.0. Ms. Diaz testified that affordability and rate competitiveness are critical metrics for Duke Energy Indiana, noting Petitioner's overall retail average realization continues to be below national and regional averages and is the lowest among its Indiana peers.

Ms. Diaz testified in response to Mr. Lantrip's assertion that Ind. Code § 8-1-39-9 does not provide necessary authority to request PISCC treatment for both debt and equity because it does not define PISCC. She testified Ind. Code § 8-1-39-9 explains that the deferral of the remaining 20%, which includes post-in-service carrying costs, aligns with the rest of the recovery applicable to the 80%, which is included in the TDSIC Rider. In other words, the 80% includes post-in-service carrying costs. The weighted average cost of capital language is interspersed in the TDSIC statute and does not limit the calculations to debt only. In addition, it is common practice for pretax returns and the weighted average cost of capital to include both debt and equity. Ms. Diaz testified that GAAP provides that both the debt and equity return can be deferred as a regulatory asset for post-in-service capitalization. Accrual of financing costs at the weighted average cost of capital, which includes an equity component along with debt, represents the comprehensive cost incurred by the Company for the period after the assets are placed in service until the collections occur. The TDSIC statute does not prohibit the application of an equity component in the PISCC calculation, and the Commission has approved the equity component in prior TDSIC cases. Ms. Diaz testified that there is no requirement under Indiana law that Duke Energy Indiana make a showing of financial distress without the additional deferral of equity, as suggested by Mr. Lantrip, and the Commission should not require it now.

Ms. Diaz testified that the TDSIC Rider limits the recovery to incremental O&M and no additional supporting documentation is needed to ensure there is no duplication of O&M expenses recovered in Petitioner's most recent base rate case, Cause No. 45253. None of the TDSIC 2.0 projects were included in Cause No. 45253, therefore none of the related project O&M would have been allowed to be included as the Commission approved O&M costs representative of the test year, 2020. The TDSIC 2.0 project O&M begins three years later and beyond~~,~~ and is directly related to TDSIC 2.0 capital projects. Because these costs are occurring after installation of the assets, Duke Energy Indiana expenses the O&M. Ms. Diaz testified that Petitioner's TDSIC 1.0 case allows the inclusion of O&M costs, and TDSIC 2.0 has not proposed any different treatment of O&M costs than what has been approved for TDSIC 1.0. She testified that Petitioner did not include any duplicative O&M in this proceeding.

Ms. Diaz testified that Petitioner and Mr. Lantrip agree that implementing depreciation netting is appropriate for TDSIC 2.0. Similar to NIPSCO's approved proposal on depreciation netting, Duke Energy Indiana will use an average rate of retirement percentage based on actual FERC Form 1 data as the source for the depreciation expense credits. Ms. Diaz disagreed with Mr. Lantrip's recommendation that Duke Energy Indiana recognize an offset in its revenue requirement for the return on net book value of retired assets as a result of the TDSIC 2.0 Plan. She testified that Petitioner is not proposing any different treatment than was approved in TDSIC 1.0. In other TDSIC cases, the Commission has specifically ordered that double-recovery concerns are addressed by depreciation netting methodologies, which Petitioner has proposed in TDSIC 2.0. The Commission likewise concluded that reductions to returns on retired assets in rate base were not reasonable and did not conform to the TDSIC statute.

8. **Cross Examination Evidence.** Mr. Pinegar testified he agreed the definition of "the best" as used in Ind. Code §8-1-10(b)(1) means, "excelling all others", "the greatest degree of excellence", and "none can be better." [Cross Examination of Stan Pinegar, A-18:14-20.] Mr. Pinegar noted that Duke Energy Indiana began its analysis of TDSIC projects in 2019. [A-19:1-2.] Mr. Pinegar also stated that he is aware of the rising commodity costs and testified that even after it noted the rising commodity costs, the Company did not perform a new cost estimate. [A-21:1-2.] Mr. Pinegar acknowledged that Duke Energy Indiana's system, as it is today – is reliable. [A-31:22-24.] Mr. Pinegar agreed that to meet the CPCN requirement in the TDSIC Statute, the Company must show a "need" for the TDSIC projects. [A-30:10-13.] Mr. Pinegar stated that his goal as Duke Energy Indiana's President was to cap the costs of this TDSIC Plan at one percent to make it more affordable. [A-40:2-5.] Mr. Pinegar stated ~~that~~ he does not view the TDSIC Projects as set in stone [A-40:8], and if costs continue to rise, Duke Energy Indiana will delay doing projects. [A-41:2-7.] Mr. Pinegar also stated that Duke Energy Indiana would not "inch closer to the $4 billion mark;" and that it "would take Commission approval to add projects and inch closer to the 2 percent or $4 billion mark." [A-41:8-14.] Mr. Pinegar agreed on cross examination that in 2020 DEI had a 1.25 SAIFI rating, and a seventeen percent decrease in SAIFI as argued by the Company still equates to a number greater than 1 – meaning on average Duke Energy Indiana's customers would still experience on average one interruption lasting longer than five minutes. [A-55:12-56:24.]

Mr. Lewis admitted on cross examination that: Duke Energy Indiana met with PowerAdvocate in 2021~~,~~ before filing~~s~~ its TDSIC Plan; PowerAdvocate provided the Company a PowerPoint that showed without question that Duke Energy Indiana's 100% cost estimate for material components were estimated far lower than actual or projected material component costs. [See OUCC CX-4 and OUCC CX1-C.] Mr. Lewis admitted that once Duke Energy Indiana had updated information from PowerAdvocate, Duke Energy Indiana added the three percent cost escalation, and Petitioner felt that the three percent escalation covered PowerAdvocate's material component fluctuations in price. [See Cross Examination of Mr. Lewis; B-55:5-18.] Mr. Lewis admitted on cross examination that he had never spoken with any customers regarding customer wants or needs related to DER. [B-32:25-B33:9.] Mr. Lewis also admitted that he had not had communications with anyone at Duke Energy Indiana to determine why it believes that such upgrades for DER are necessary. [B-30:19-22.]

Mr. Dickey admitted on cross~~-~~ examination regarding data requests that Duke Energy Indiana did not provide outage data for various projects. [See OUCC CX-9.] Mr. Dickey stated that he and Petitioner did not know the algorithm contained in the modeling from B&V, and Duke Energy Indiana itself could not replicate the B&V and Copperleaf findings. [See Cross ~~E~~Examination of Mr. Dickey, C-24:10-25.] Mr. Dickey could not point to indices in which it is proper to measure transmission systems using SAIDI and SAIFI, and could not refute that the IEEE 1366 Index regarding SAIDI and SIAFI is only used for distribution systems and not transmission systems. [C-15:17-25; C-18:5-7; Public's Ex. No. CX-8.] Mr. Dickey admitted that he has no indices or treatises that recognize "Grid CMI" as a proper measurement of transmission improvement. [C-60:4-20.]

Mr. Shields admitted in cross examination that he did not make a determination that Petitioner's cost estimates were "the best", he only evaluated ***some*** of the projects based on "reasonability." [See Cross Examination of Mr. Shields, C-60:4-19.]

~~8.~~9. **Statutory Requirements.** Ind. Code § 8-1-39-10 (the "TDSIC Statute") permits a public utility to petition the Commission for approval of the utility's TDSIC plan for eligible transmission, distribution, and storage improvements, which may include for approval of a TED project. The Commission's order must include: (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; and (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 TDSIC plan is reasonable, it 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).

Ind. Code § 8-1-39-2(a) defines "eligible transmission, distribution, and storage system improvements" as 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 described in the public utility's TDSIC plan and approved by the Commission under Ind. Code § 8-1-39-10 and authorized or TDSIC treatment; or approved as a TED project under Ind. Code § 8-1-39-11. Under Ind. Code § 8-1-39-2(b), the term "eligible transmission, distribution, and storage system improvements" includes: (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 § 8-1-39-7.8 requires that a TDSIC plan cover a period of at least five years and not more than seven years.

Ind. Code § 8-1-39-9(d) provides that a public utility may not petition the Commission for approval of a utility's TDSIC plan within nine months after the date of a Commission order changing the utility's basic rates and charges with respect to the same type of utility service.

Ind. Code § 8-1-2-0.5 requires that the Commission must use all practicable means and measures to protect the affordability of utility services for present and future generations of Indiana citizens when utilities plan for investment in infrastructure.

Ind. Code § §8-1-2-6 requires that a utility must show that its property is used and useful.

~~9.~~10. Commission Discussion and Findings.

A. Duke Energy Indiana's TDSIC 2.0 Plan and Eligible Improvements.

~~Duke Energy Indiana's TDSIC 2.0 Plan is comprised of projects to improve reliability, advance grid hardening and resiliency, enable expansion of renewable and distributed generation, and facilitate economic development growth. Duke Energy Indiana's TDSIC 2.0 Plan identifies and describes the transmission and distribution projects, the timing of the projects, and why they are necessary and beneficial to customers. Duke Energy Indiana's TDSIC 2.0 Plan and attached exhibits identify what projects will be undertaken, when they will be undertaken, and why these projects are necessary and beneficial. The evidence presented demonstrates that the improvements are being undertaken by Duke Energy Indiana for purposes of safety, reliability, system modernization, or economic development. Duke Energy Indiana also showed that the proposed improvements were not included in its rate base in its most recent general rate case.~~

OUCC witness Dr. Shull challenged the sufficiency of Duke Energy Indiana's TDSIC 2.0 Plan, as Petitioner did not provide outage data~~,~~ or any empirical evidence showing the necessity of any of its proposed TDSIC projects. Dr. Shull was particularly concerned with the inclusion of nineteen transmission line projects arguing that they are not for purposes of safety, reliability, or modernization. Duke Energy Indiana's witnesses admitted Petitioner did not provide historical outage data to show the necessity of such projects. Duke Energy Indiana also failed to provide in its case-in-chief that any of the 19 transmission projects provided capacity upgrades~~,~~ or were at the end of their useful lives. ~~Through its direct and rebuttal testimony, Duke Energy Indiana provided evidence that the transmission projects identified by Dr. Shull are projects to rebuild aged and deteriorated sections of circuits or replace and upgrade specific switches located within other segments of the circuits.~~ Mr. Dickey ~~e~~attempted to rebut Dr. Shull's testimony by claiming that ~~xplained that~~ those circuits directly supply 25 Duke Energy Indiana substations and 11 substations owned by others. However, such improvements to other utilities' substations does not show the benefit to the Company's customers, as required by the Statute (Ind. Code §8-1-39-10(b)(3). Additionally, Duke Energy Indiana is required to show the necessity of such improvements in its case-in-chief testimony. Duke Energy Indiana attempts to get additional data it failed to provide in its case-in-chief testimony in its rebuttal testimony, however, Duke Energy Indiana is reminded that rebuttal evidence is limited to evidence to explain, contradict, or disprove evidence offered by the adverse party, it is not an opportunity to correct deficiencies in Petitioner's case-in-chief. ~~Those circuits were selected based on several factors including the longer-term history of outages, assessed age, and condition of the poles and other equipment, outdated circuit design, and other prioritizing factors. Mr. Dickey testified that these circuits were selected as being among the highest outage concerns, with a total of 273 outages resulting in 11.78 million Grid CMI from 2015-2021. Mr. Dickey also testified Duke Energy Indiana has evaluated and selected each of these transmission line rebuild projects to improve reliability by reducing the risk of outages from aged and deteriorated line equipment, and performing these projects is in the best interest of Duke Energy Indiana's customers. Each of the projects included in TDSIC 2.0 were evaluated within the model and study performed by B&V and showed a strong reliability improvement due to reduced quantity and duration of outages. Duke Energy Indiana's evaluated reliability benefits justify and validate the public convenience and necessity of these projects. In addition, these circuit rebuilds will provide a capacity increase between approximately 27% and 123%, due to the larger conductor size. Mr. Dickey asserted that these projects will also upgrade and modernize the line by installing optical groundwire as the static shield wire, which includes fiberoptic communications fibers to allow digital telecommunications from one end of the circuit to the other.~~

The Commission also heard testimony ~~explaining~~ that Duke Energy Indiana worked with its stakeholders to identify projects to be considered for TDSIC 2.0. However, on cross~~-~~examination Mr. Lewis admitted that he had never spoken with a customer regarding the TDSIC Plan. In spite of several consumer groups being represented by counsel, no consumer groups filed any testimony in support of any projects. Hoosier Energy witness Mr. Mabrey testified, at the evidentiary hearing, that Hoosier Energy and Duke Energy Indiana worked together to identify certain improvements that provide benefits to Duke Energy Indiana retail customers while also benefiting the larger grid, Hoosier Energy, its member systems and their consumers. However, Mr. Mabrey could not identify any specific project in its prefiled testimony or at the evidentiary hearing that it requested inclusion of in the Company's TDSIC Plan. Therefore, it remains that no Duke Energy Indiana customer testified in support of any project improvement, and Duke Energy Indiana's discussion in testimony surmounts to hearsay and speculation of customer wants. ~~The improvements include improvements to eight substations, such as relay and breaker upgrades, bus work upgrades, transformer bank replacements, switch upgrades from manual to motor operated, and conversions from straight bus to ring bus, as well as improvements to 17 transmission lines such as switch upgrades from manual to motor operated, SCADA controls, line rebuilds including wood pole replacements with steel poles and static wire replacement.~~

OUCC witness Dr. Shull also challenged Duke Energy Indiana's addition of electrical system devices for future DER installations, testifying that Petitioner had not demonstrated a customer demand for DER, and it would be prudent to wait and build its system when customers~~'~~ seek~~ought~~ interconnection. Dr. Shull further testified ~~that~~ Petitioner has not demonstrated a customer demand for DER, and it would be prudent for Duke Energy Indiana to wait and build its system to meet specific customers' DER needs. In rebuttal, Duke Energy Indiana argued ~~explained~~ that the enablement of DER was an ancillary benefit to the Company's proposed TDSIC 2.0 investments ~~-~~with the primary benefit being reliability. Specifically, Mr. Lewis testified that the proposed investments that also impact DER benefit all Duke Energy Indiana customers by reducing outage impacts with respect to frequency, grid impact, recovery time, and cost. However, no direct evidence was provided regarding the outage impacts or costs, outside of the DER analysis. Further, Mr. Lewis explained that improving system capability to enable DER was not an optimization criterion used in B&V's Cost Benefit Analysis, rather these projects, which result in two-way power flow capability, were selected due to their reliability benefits and value to the T&D system. Nonetheless, Petitioner did not provide any direct evidence related to interconnection requests, or where such DER was to be built in relation to the proposed TDSIC projects to enable DER. ~~Duke Energy Indiana's annual Distributed Generation Interconnection Reports submitted to the Commission demonstrate the increased demand from the Company's customers, increasing from 43 applications in 2011 to 493 in 2021. Designing a system around already installed DER is not an effective or efficient way to plan for what is known to be coming and could delay customer installations and reduce economic development opportunities for Indiana communities. Accommodating two-way power flow capability is needed now to manage and accept customer-generated and stored energy resources. We agree with Petitioner that a proactive approach to DER integration will benefit customers and the grid as a whole. To do the opposite could lead to unacceptable delays for customers being able to connect to the grid and create undesirable conditions on the T&D system.~~ While Duke Energy Indiana states that such an approach to install additional two-way power flow, ~~and~~with other benefits, is a "proactive" approach, we are reminded that all such utility plant must meet with the statutory requirement that it be "used and useful." The Court of Appeals has long held that "[u]nnecessary plant capacity is not used and useful for rate making purposes and should not be included." *Indiana-Am. Water Co. v. Ind. Off. Of Util. Consumer Couns*., 844 N.E.2d 106, 111 (Ind. Ct. App. 2006) *citing L.S. Ayres & Co. v. Indpls. Power & Light Co*., 169 Ind. App. 652, 683, 351 N.E.2d 814, 834 (1976), *trans. denied*. In that case, Indiana American provided testimony that a fifth water pump was needed to meet peak demand and noted that the fifth pump had not yet been used but claimed it will be needed "at some point in the future." *Id*. at 111 (Emphasis added.) The Commission in its findings noted that, despite previously allowing this pump into rate base, the Commission:

> [S]hall make our decision based on the evidence of record that we now have before us. We find that [IAWC] did not provide evidence to support the time frame within which this engineering feature will be used and useful. Further, we find [IAWC's] evidence lacked information that we deem necessary in order to allow this plant in rate base. *Id.*

Based on the evidence presented, we find Duke Energy Indiana has not met its burden of proof to show that such DER projects will be used and useful. Petitioner did not provide any time frame within the record to show when such DER projects would be used and useful. Consistent with the Commission's prior ruling in *Indiana-American*, in which the Court of Appeals upheld the Commission's decision to deny speculative needs for future demand, the Commission denies Duke Energy Indiana's request herein. ~~'s proposed TDSIC 2.0 improvements are being undertaken by Duke Energy Indiana for purposes of safety, reliability, system modernization, or economic development, and meet the criteria established by the TDSIC Statute. We further find that the~~

~~proposed projects are "eligible improvements" as defined in Ind. Code § 8-1-39-2 and were not included in Duke Energy Indiana's most recent rate case.~~

B. Best Estimate of Costs. Ind. Code § 8-1-39-10(b)(1) requires that the Commission's order on a TDSIC Plan must include "[a] finding of the best estimate of the cost of the eligible improvements included in the plan."

Duke Energy Indiana's TDSIC 2.0 proposes six years of defined investment totaling $2,140,185,171. The record demonstrates that $1,144,816,889 of the total cost estimate is distribution cost; $1,837,552,403 is transmission cost; and potentially $157,815,879 of targeted economic development project cost. Exhibit 2-A provided year-by-year cost estimates and an associated summary of the TDSIC 2.0 Plan's cost by FERC account.

Duke Energy Indiana developed cost estimates for the projects included in TDSIC 2.0 using the AACE Cost Classification System. As a general matter, Duke Energy Indiana presented Class 2 cost estimates for many of the proposed projects for Plan Years 1 and 2. Class 3 and Class 4 estimates were developed for the remaining projects. Duke Energy Indiana's confidential workpapers included electronic spreadsheets underlying the sortable list. Duke Energy Indiana's confidential workpapers also included the ~~detailed~~ cost estimates for TDSIC 2.0 projects. Examples of the Class 2, 3, and 4 cost estimates were provided in Duke Energy Indiana's Confidential Exhibits 2-B and 3-A.

The Commission has not in previous TDSIC cases determined what "the best estimate of cost" means, as used in the TDSIC statute. Indiana Courts have consistently held that "when a statute is clear and unambiguous, we apply the rules of statutory construction and interpret statutory language in its plain, ordinary, and usual sense." *Cty. of Lake v. Pahl*, 28 N.E.3d 1092, 1104 (Ind. Ct. App. 2015), *reh'g denied*, *trans. denied*. Petitioner's witness Stan Pinegar accepted that "the best" as referenced in the Statute, means, "excelling all others", "the greatest degree of excellence", and "none can be better." [Cross Examination of Stan Pinegar, A-18:14-20.] OUCC witness, Dr. Shull, asserts that Petitioner has not accurately accounted for recent increases in commodity prices and inflation rates and thus has not presented the "best estimate of the cost.~~,~~" Additionally, OUCC Ex. CX-C1 demonstrates that Duke Energy Indiana's cost estimates included in its TDSIC Plan were underestimated, even from its own estimations, at the time of filing the Company's TDSIC 2.0 Plan. While Duke Energy Indiana speculates ~~that~~ a three percent escalation will cover the rising costs, its own futures predictions show this is not accurate. While Duke Energy Indiana's non-engineering witnesses, Mr. Dickey and Mr. Lewis stated that Duke presented the best cost estimates, neither are engineers qualified to make such a statement. Indeed, Petitioner's only engineer witness specifically noted that he could not state Duke Energy Indiana's estimates were "the best"; he only reviewed the estimates for "reasonableness." As Duke Energy Indiana presents no engineering witness to rebut Dr. Shull's assessment that the cost estimates are not "the best estimate of costs", and as the Company's cost estimates fail to account for the 30-55 percent shift in material component costs, Duke Energy Indiana has failed to meet the statutory requirement. The statute does not require "reasonableness" as Duke Energy Indiana seems to argue, the statute expressly requires "the best." ~~we find that Duke Energy Indiana presented~~

~~extensive evidence detailing the methodology used to develop its cost estimates. Specifically,~~ Mr. Lewis explained that Duke Energy Indiana used its mid-2021 estimates as baselines for the costs of material, labor, and indirect costs for all projects were escalated at the rate of 3% per year until an individual project's in-service year was reached, through 2028 in some cases. The escalation value of 3% was derived from the collaborative mid-2021 study performed by Duke Energy Indiana and PowerAdvocate. Mr. Lewis testified that Duke Energy Indiana and PowerAdvocate observed prices increasing sharply in the latter half of 2020 and continue to increase until early 2022. The projection then shows a general decrease in commodity and utility component costs through 2025, and finally a return to a typical aggregate 3% escalation rate in the outer years of 2026 – 2028. Petitioner does not adjust any of its proposed material component acquisitions for 2022, and merely speculates that by 2026 the number will level out. However, the Plan requires material components to be purchased far ahead of 2026. ~~PowerAdvocate provided a range of commodity and utility component costs over time, with high, mid, and low overall forecasted values projected by component type.~~ Duke Energy Indiana argues that it used ~~this forecast from~~ PowerAdvocate's forecast to develop a reasonable escalation rate for TDSIC 2.0. Again, Duke Energy Indiana is not required to provide a "reasonable" forecast or a "reasonable" estimate, the statutory language is explicit, cost estimates must be "the best." Duke Energy Indiana fails to rebut the argument of Dr. Shull, as the sole engineering witness in this case, who determined Petitioner's cost estimates were not "the best estimate of costs." Additionally, even if the standard were "reasonableness", Petitioner's estimates with stale cost estimates do not represent a reasonable estimate, as demonstrated by PowerAdvocate's presentation showing Duke Energy Indiana's estimates were far lower than actual or projected costs. ~~Mr. Pinegar further testified, at the evidentiary hearing, that Duke Energy Indiana's robust procurement practices allow it to manage price uncertainty.~~

~~No party filed testimony contesting the level of contingency Duke Energy Indiana included in TDSIC 2.0. Mr. Lewis testified that the Company included a 15% contingency for the entirety of TDSIC 2.0 and explained that since projects go into service each year, contingency is broken out for each year. Mr. Lewis also explained that if contingency is found to be needed to a lesser extent than expected in year one the remaining amount would extend to future years to account for ongoing risk that are more backend loaded to a plan of this scale.~~

~~Ind. Code § 8-1-39-10 requires the Commission order to include a "finding of the best estimate" of the cost of the proposed improvements. At this juncture, the Commission is not tasked with reviewing actual project costs. After approval of a TDSIC plan, Ind. Code § 8-1-39-9 establishes procedures for TDSIC trackers, providing that "[a]ctual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates." Duke Energy Indiana will also utilize Section 9 tracker update filings to provide refined Class estimates for projects in later years of the TDSIC 2.0 Plan and, to the extent Duke Energy Indiana cost estimates were to exceed those approved herein, they will be evaluated in such filings. Moreover, Ind. Code § 8-1-39-14 establishes a limitation on TDSIC recovery within a 12-month period.~~

Based on the evidence presented, we find that Duke Energy Indiana only addresses the "reasonableness" of cost estimates and does not properly consider the Statute's explicit requirement of "the best estimate of costs." ~~the record demonstrates that the total, estimated cost of Duke Energy Indiana's TDSIC 2.0 Plan of $2,140,185,171 rests on a sound factual and analytical foundation and is reasonable. Duke Energy Indiana's methodology was robust, sound, and reasonable.~~ Accordingly, we find that Duke Energy Indiana has failed to provide the best estimate of costs. ~~find the best estimate of the cost of the eligible improvements included in TDSIC 2.0 is the estimate provided by Duke Energy Indiana.~~

C. **<u>Public Convenience and Necessity</u>.** Ind. Code § 8-1-39-10(b)(2) requires that an order on a TDSIC plan must include "[a] determination whether public convenience and necessity require or will require the eligible improvements included in the plan."

Duke Energy Indiana argues that ~~The evidence of record in this Cause demonstrates that~~ the Distribution System Circuit Improvements portion of TDSIC 2.0 (which accounts for $704,060,933 (direct capital) of TDSIC 2.0) is largely intended to focus on value to the customer through replacement of the aging assets and expansion of technology to modernize Duke Energy Indiana's electric grid with technologies that support improved reliability. Program categories include Circuit Backbone Reliability Uplift, Overhead Lateral Reliability Uplift, Underground System Uplift, 4kV Conversion, and Inspection Based Programs. The evidence of record further demonstrates that the Distribution System Substation Improvements portion of TDSIC 2.0 (which accounts for $176,965,506 (direct capital) of TDSIC 2.0) is largely intended to improve reliability and resiliency, while improving capacity, though various Substation Hardening & Resiliency sub-programs. Duke Energy Indiana further argues ~~The evidence also demonstrates~~ that the Transmission System Line Improvements portion of the of TDSIC 2.0 (which accounts for $494,662,048 (direct capital) of TDSIC 2.0) is intended to improve reliability and flexibility through various Line Hardening & Resiliency sub-programs. The evidence demonstrates that the Transmission System Substation Improvements portion of the of TDSIC 2.0 (which accounts for $198,038,203 (direct capital) of TDSIC 2.0) is intended to improve reliability and resiliency, while improving capacity, though various Substation Hardening & Resiliency sub-programs.

~~TDSIC 2.0 follows the requirements of the TDSIC statute and achieves the legislative intent of making new and replacement transmission, distribution, and storage system investments for the purpose of safety, reliability, system modernization, and economic development. The eligible investments are essential in protecting the integrity, safety, and reliable operation of the system and will also enhance the ability of Duke Energy Indiana and its customers to take advantage of the rapid development of alternative technological options, such as electric vehicles and DERs.~~

The OUCC argued that some of the eligible improvements included in TDSIC 2.0 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. Dr. Shull asserted that the Petitioner claims its system is already highly redundant and reliable and has provided no support for an added layer of redundancy. Dr. Shull further stated that Duke Energy Indiana's proposed level of additional redundancy is unnecessary and not supported by evidence. Specifically, Dr. Shull stated that the Company has not shown any historical data or other support showing it needs this added layer of redundancy. Additionally, Duke Energy Indiana Witness Dickey admitted ~~that~~ in data responses, Petitioner did not provide such outage data. Without such evidence Duke Energy Indiana cannot show a need for these projects. ~~Mr. Dickey testified that projects within TDSIC 2.0 were designed to address specific "single point of failure" vulnerabilities on the system. Mr. Dickey explained that eight of the projects specifically identified as unnecessary by the OUCC were designed to rebuild and replace deteriorated sections of circuits.~~ Dr. Shull also testified regarding seventeen transmission line projects in which Petitioner failed to provide empirical evidence or support ~~regarding~~that the public convenience and necessity requires~~ing~~ the replacement or rehabilitation of such transmission lines to improve reliability. Dr. Shull testified that those transmission projects are not necessary replacements for improved reliability. Duke Energy Indiana presented no direct evidence regarding any capacity changes or other upgrades. The projects are merely replacing undeteriorated transmission lines, with the exact same equipment. Further, Duke Energy Indiana provides no evidence that these specific projects result in a reduction in customer interruption or customer minutes interruption or improved reliability.

Petitioner failed to provide evidence, such as outage data, or other empirical evidence to show a need for such projects. Petitioner has failed to demonstrate that all requested projects are necessary. Unnecessary projects are never affordable.~~substantial evidence in this Cause shows that the projects included in Duke Energy Indiana's TDSIC 2.0 Plan will serve the public convenience and necessity.~~

D. Incremental Benefits Attributable to the TDSIC 2.0 Plan. Ind. Code § 8-1-39-10(b)(3) requires that an order on a petition for approval of a TDSIC plan must include "[a] determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan."

Duke Energy Indiana, with the assistance of B&V, included non-financial "benefits," and attempted to monetize such "benefits" ~~monetized,~~ from the customer experience perspective, the value of avoiding service outages, particularly CI and CMI. However, Mr. Shields admitted on cross examination that such "benefits" including "customer satisfaction" did not even consider rising electric costs. Mr. Shields explained that B&V's Investment Plan Analysis began with detailed benefit mapping, as depicted in Table 3 and Table 4 of his direct testimony. Duke Energy Indiana's analysis did not attempt to quantify all project benefits. ~~, but rather focused on benefits that are easily quantified and tracked. For example, the record shows that~~ Duke Energy Indiana's internal team identified 57 projects that could not pass even its own cost-benefit test ~~that were not selected through the Investment Plan Analysis~~, but were included in TDSIC 2.0 because they impacted critical customers, such as hospitals and schools.~~, and enhanced the grid with other benefits that were not quantified in the Investment Plan Analysis.~~ . The Company used B&V's "Value Model" incorporating Copperleaf's modeling to determine a cost-benefit analysis. ~~Ultimately P~~projects that scored at or above 1.0 had, in Duke Energy Indiana's model, benefits that outweighed the associated costs. ~~As shown in Table 7 of Mr. Shield's direct testimony, the~~

~~total portfolio, inclusive of all projects proposed in TDSIC 2.0, carried a benefit cost ration of 2.8, well above 1.0. Mr. Lewis testified that contingency was not included in B&V's Investment Plan Analysis. However, Mr. Lewis explained that even with a full allocation in the Investment Plan Analysis, TDISC 2.0 continues to show a benefit to cost ratio of 2.4. Thus, TDSIC 2.0 will provide a net benefit that exceeds the cost of the eligible improvements whether considered on a nominal or a present value basis.~~

The OUCC argued that the Commission should deny the TDSIC 2.0 Plan due to the~~its~~ inability of any party or the Commission to verify the reasonableness or accuracy of B&V's Copperleaf modeling logic that ~~optimized and~~ selected the projects contained in TDSIC 2.0. Dr. Shull testified that it is impossible to verify whether Copperleaf's modeling logic is reasonable, or the calculations are accurate. The Commission agrees with Dr. Shull. Not only can no party verify the Plan, Duke Energy Indiana itself admitted in cross~~-~~ examination that it cannot verify the findings of Copperleaf as it does not know Copperleaf's algorithms. We also question the potential inflation of benefits used in B&V's "Value Models". Such non-financial "benefits" appear to be duplicative, and fall far outside of the traditional cost-benefit analyses that have been approved by the Commission in other TDSIC cases. ~~However, we find persuasive the testimony provided from B&V witness Mr. Shields who explained how the Copperleaf model functioned to optimize project investments to ensure high value projects were located in the areas on the system that produced the highest value. In addition, we note the testimony from Mr. Lewis that Duke Energy Indiana's subject matter experts developed the inputs to the Copperleaf model. The overall modeling prepared for Duke Energy Indiana's proposed TDSIC 2.0 Plan has provided this Commission with the information it requires to determined that the estimated costs of the eligible improvements included in the Plan are justified by incremental benefits attributable to the Plan. We therefore disagree with the OUCC that Duke Energy Indiana's proposed TDSIC 2.0 Plan should be denied.~~

~~The record evidence demonstrates that Duke Energy Indiana's TDSIC 2.0 is proposed to provide reliability benefits to customers, such as reduction of frequency and duration of interruptions, hardening and resiliency of the grid, and modernizing the grid to manage the ever-growing renewable, distributed generation on our system. In doing so, TDSIC 2.0 provides incremental benefits to Duke Energy Indiana retail and wholesale customers.~~

Accordingly, based on the evidence presented, we find that Duke Energy Indiana has not presented sufficient evidence to show that the costs presented outweigh the benefits of its TDSIC 2.0 Plan. ~~sufficiently prioritized and optimized the incremental benefits of TDSIC 2.0 and otherwise shown a sound basis for the proposed projects and associated costs. Therefore, the Commission's determination is that the estimated costs of Duke Energy Indiana's TDSIC 2.0 projects are justified by incremental benefits attributable to TDSIC 2.0.~~

E. Affordability. The Indiana General Assembly has made a policy declaration to use all practicable means and measures in a manner calculated to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services for present and future Indiana citizens. Ind. Code § 8-1-2-0.5. Thus, if the General Assembly declared its policy to protect affordability, the Commission must consider the affordability of this Plan. The statutory declaration to consider affordability is another layer of protection that the Indiana General Assembly enacted to protect ratepayers. This policy consideration that affordability must be protected while investments are made in infrastructure is in addition to the constraint of the two percent cap included in the TDSIC Statute. As the Commission herein finds in consideration of the unsurety of the costs of the Plan, the undefined and potentially inflated benefits, the inability of any party or the Commission to replicate the Copperleaf findings, the failure to show the necessity of the projects, and the general overall economic concerns of ratepayers, the Commission rejects Petitioner's Plan as insufficient to protect affordability as required by Ind. Code § 8-1-2-0.5. ~~**Duke Energy Indiana's TDSIC 2.0 Plan is Reasonable.** Based upon our review of the evidence presented and our discussion above, we find Duke Energy Indiana's TDSIC 2.0 Plan is reasonable. As discussed above, Duke Energy Indiana's TDSIC 2.0 satisfies the applicable statutory requirements. TDSIC 2.0 is reasonably designed to incrementally maintain or improve safety, reliability, and resiliency of Duke Energy Indiana's system. TDSIC 2.0 also includes certain projects intended to modernize Duke Energy Indiana's electric system. The record establishes that Duke Energy Indiana's TDSIC 2.0 Plan is based on a logical approach and sound analysis that presents the best estimate of the cost of the investments. We also find that Duke Energy Indiana has provided sufficient evidence that its cost estimates are best estimates, that public convenience and necessity require or will require the eligible improvement in the TDSIC 2.0 Plan, and that the benefits of TDSIC 2.0 justify its costs. Accordingly, based upon our review of the evidence of record and the foregoing considerations of each component of Ind. Code § 8-1-39-10, we find that Duke Energy Indiana's TDSIC 2.0 Plan is reasonable and is therefore approved. In accordance with Ind. Code § 8-1-39-10(b), we authorize TDSIC treatment for the improvements described in TDSIC 2.0, including costs incurred prior to the date of this Order.~~

F. Accounting and Ratemaking. As summarized above, Duke Energy Indiana requests Commission approval to recover 80% of the TDSIC 2.0 costs via its existing approved TDSIC Rider that uses the class revenue allocation factors based on firm load developed in the most recent base rate case in Cause No. 45253, and deferral with carrying costs of 20% of the TDSIC 2.0 costs for subsequent recovery in Petitioner's next general retail electric base rate case. The Commission approved Duke Energy Indiana's electric TDSIC mechanism in its 44720 Order, allowing for the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorization to defer, until recovery though the TDSIC, 80% of the post-in-service TDSIC costs of the TDSIC projects, including carrying costs, depreciation, O&M expenses, and taxes.

As provided for in Ind. Code § 8-1-39-13(b), Duke Energy Indiana requests authority to increase the authorized net operating income for purposes of the Ind. Code § 8-1-2-42(d)(3) earnings test. Based on our review of the TDSIC Statute, our discussions above regarding transmission upgrade projects, DER systems projects, the absence of the "best estimate" of project costs as required by Ind. Code §8-1-39-10(b)(1), insufficient evidence demonstrating the public convenience and necessity require, or will require, the proposed projects as required by Ind. Code §8-1-39-10(b)(2), the failure to demonstrate the Plan's estimated costs are justified by incremental benefits attributed to the Plan as required by Ind. Code §8-1-39-10(b)(3), and our conclusion that the Plan as proposed is inconsistent with Indiana's state policy for protecting affordability of utility service as set forth in Ind. Code §8-1-2-0.5, we find that Duke Energy Indiana's request should be denied~~approved~~. While this decision may technically render further discussion on ratemaking and accounting issues moot, there are important issues here which should be addressed in the interest of providing guidance to Duke Energy Indiana should it decide at some later date to file a new TDSIC Plan with this Commission.

i. **Post In-service Carrying Costs.** Duke Energy Indiana seeks approval for the accrual of post-in-service carrying costs, which includes both debt and equity financing, on approved capital expenditures, including accrual on previously computed post-in-service carrying cost amounts, from the in-service date until such costs are included in the Company's rates under TDSIC or in base rates. These carrying costs will accrue at rates equal to Duke Energy Indiana's most recently approved weighted average cost of capital. AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates, or when the projects are placed in service. Ms. Diaz testified that Duke Energy Indiana also seeks Commission authority to create regulatory assets to recover post-in-service carrying costs, O&M, depreciation, and property taxes associated with the projects until such costs are reflected in the TDSIC tracker rates or Duke Energy Indiana's retail electric rates.

OUCC witness Mr. Lantrip argued Duke Energy Indiana should be able to include only the debt financing in its post-in-service carrying costs. On rebuttal, Ms. Diaz stated that the TDSIC Statute does not prohibit the application of an equity component, and GAAP provides for both debt and equity return deferral as a regulatory asset. She further stated that the Commission has approved both the equity and debt components in prior TDSIC cases.

We find the OUCC's position most persuasive. Ind. Code §8-1-39-9(b) does not specify that PISCC costs must include both the debt and equity components. The Commission has previously approved calculating PISCC costs using the Allowance for Funds Used During Construction ("AFUDC") rate of the utility, as opposed to the WACC (which includes an equity component) as proposed by Petitioner. See the Commission's Order in Cause No. 44339. ~~the~~ ~~p~~Petitioner's proposal is contrary to GAAP, which GAAP does not permit the capitalization of incurred costs that are not charged to expense. Accounting Standards Codification ("ASC") 980-340-25-1 states, in part, "An enterprise **shall capitalize all or part of an incurred cost that would otherwise be charged to expense**…" (emphasis added). With respect to PISCC costs, the only cost that would be charged to expense is the interest expense related to the debt portion of the PISCC calculation. The equity portion of PISCC does not get charged to expense and therefore is normally not included in the deferral of post-in-service AFUDC. Unlike debt cost, post-in-service deferral of equity does not improve earnings erosion because GAAP does not permit the equity portion to be included on the company's income statement. Duke Energy Indiana's proposal allows the company to recover more dollars from ratepayers than it would be permitted to be recorded on its income statement.

Petitioner is correct that the Commission has, in other TDSIC cases, included the equity portion of deferred expenses in the PISCC calculation. However, the Commission is not required by the TDSIC statute to do so, nor are we bound to blindly follow a prior decision. Every case is impacted by the particular circumstances, evidentiary record and controlling statutes, with prior orders potentially influencing our decision as well. Considering the unprecedented cost of the Company's proposed Plan, the applicable GAAP rules, the Commission's discretion on this topic (Ind. Code §8-1-39-13(a)(5) explicitly allows consideration of "other information" in calculating TDSIC costs), our increased focus on Indiana's affordability statute, and the absence of evidence from the company it will suffer financial distress without the PISCC associated with the deferred equity, we would deny the company's proposed request if we had approved other portions of the Plan. ~~and that the equity portion does not get charged to expense and therefore is normally not included in the deferral. On rebuttal, Ms. Diaz stated that the TDSIC Statute does not prohibit the application of an equity component, and GAAP provides for both debt and equity return deferral as a regulatory asset. She further stated that the Commission has approved both the equity and debt components in prior TDSIC cases and Duke Energy Indiana is not seeking any different treatment than what has already been approved. Consistent with our previous approval of including both debt and equity components in the post-in-service carrying costs, we approve the use of both debt and equity financing for post-in-service carrying costs for this case.~~

ii. **Plan Development Costs.** Duke Energy Indiana has requested recovery of the expenses incurred for retaining B&V as a consultant and witness for this proceeding. B&V performed analyses as part of this proceeding, and Mr. Shields provided testimony that summarizes these analyses. Based on the evidence provided in this case, and the absence of objections by any other party, we would have found ~~find that~~ this to be ~~is~~ a reasonable request. ~~and the expenses should be approved for recovery over a three-year period.~~

iii. **Depreciation.** Ms. Diaz also explained that Duke Energy Indiana's proposal regarding depreciation on TDSIC 2.0 projects and stated that Duke Energy Indiana is proposing to utilize the applicable depreciation rates for transmission and distribution assets approved in its most recent rate case, Cause No. 45253. Ms. Diaz is also proposing to offset depreciation expense for retired plant using a five-year average of FERC Form 1 retirement ratios. Evidence provided by Ms. Diaz in Exhibit 6-A demonstrates that TDSIC 2.0 does not result in an average aggregate increase in Duke Energy Indiana's total retail revenues of more than two percent in a 12-month period. As n~~N~~o party presented evidence challenging this requested relief, we would have found ~~. We find~~ Duke Energy Indiana's proposals ~~are~~ reasonable~~, and they are approved~~.

iv. **Recovery of Operation and Maintenance (O&M) Expense**. Mr. Lantrip recommended the Commission deny ~~raised a concern about O&M and that~~ Duke Energy Indiana's ~~should be~~ request for recovery of $131M in O&M expenses. Public's Ex. No.1 at 14. ~~limited to the amount Duke Energy Indiana has~~ Mr. Lantrip argued existing plant in rate base already has O&M embedded in rates, while new TDSIC improvements that replace existing plant should require less O&M, not more, and the embedded O&M in current rates isn't being used for O&M on the replaced plant that is no longer in service and used and useful. He also testified as to Petitioner's lack of evidentiary support demonstrating the requested $131M was above and beyond the O&M expenses embedded in its base rates (from Cause No. 45253). ~~justified as incremental expense above and beyond what was approved in its base rate case, Cause No. 45253.~~ Ms. Diaz's rebuttal testimony stated~~ed~~ that the O&M in this case is project specific to the TDSIC 2.0 projects and has not been included in the prior TDSIC 1.0 plan nor was it included in Duke Energy Indiana's most recent base rate case, Cause No. 45253.

Ind. Code §8-1-39-2(a)(2) requires eligible TDSIC improvements are "not included in the public utility's rate base in its most recent general rate case." "TDSIC costs" which may be recovered for eligible improvements (defined in Ind. Code §8-1-39-7 and which include O&M) therefore, also cannot be included in the public utility's rates set in the most recent general rate case. Petitioner has the burden of proving the proposed TDSIC improvements and their associated costs are not part of the utility's existing rate base or rates. This burden falls on no other party.

The Company's self-serving assurances, whether in data request responses or testimony, that none of the $131M in requested O&M is included in base rates are inadequate to meet its evidentiary obligation absent any other objective, verifiable supporting evidence. Arguing that a project's construction began three years after the most recent rate case is not proof that expenses for that project are not part of existing rates. Pole replacement programs might be one such example.

Duke Energy Indiana's requested $131M in O&M ignores the fact that the company will be simultaneously recovering from ratepayers, in base rates, O&M for all existing plant that is replaced, removed from service and is no longer used and useful as part of the Plan. Traditional ratemaking would not typically remove retired / replaced plant from rate base outside of a general rate proceeding. Thus, ratepayers will continue to pay to maintain plant that provides them no service and no benefit. This ~~is~~ outcome directly contradicts the purpose of Indiana's affordability statute. Had we not reached our earlier case-dispositive decisions, this topic would seem to be another area ripe for Commission consideration under Ind. Code §8-1-39-13(a)(5), including a potential adjustment the calculation of an appropriate pre-tax return as we discussed in our Order in AES Indiana's TDSIC Plan, Cause No. 45264. ~~We concur with Ms. Diaz and approve the inclusion of O&M expense in this case.~~

v. **Retirement of Replaced Assets.** Mr. Lantrip recommended that Duke Energy Indiana recognize an offset in its revenue requirement for the return earned on the embedded net book value of retired assets. On rebuttal, Ms. Diaz noted that the Commission has previously rejected this recommendation, and the Commission has specifically approved ~~ordered that double-recovery concerns are addressed by~~ depreciation netting methodologies to address this issue.~~, which Duke Energy has proposed in this case.~~

Similar to our discussion above regarding O&M, traditional ratemaking would not typically remove retired / replaced plant from rate base outside of a general rate proceeding. Thus, ratepayers continue to pay a return "on" the net book value, as well as a return "of" the replaced / retired plant that provides them no service and no benefit. Once again, this ~~is~~ outcome directly contradicts the purpose of Indiana's affordability statute. This causes Duke Energy Indiana's rates to be unnecessarily higher and less affordable. While t~~T~~he Commission has ~~also~~ previously considered and rejected OUCC's position on this issue in prior TDSIC plan cases, the individual circumstances of this case, with this evidentiary record, are such that had we not reached our earlier case-dispositive decisions, this topic would also be ripe for Commission consideration under Ind. Code §8-1-39-13(a)(5). A potential adjustment the calculation of an appropriate pre-tax return, as we discussed above, might well be in order. Cause No. 45264. ~~concluded that reduction to returns on retired assets in rate base are not reasonable and do not conform to the TDSIC statute. Specifically, we have found:~~

~~"…with regard to… arguments about potential duplicative or double recovery, we note that we have recently addressed this very same argument offered in the context of IPL's electric TDSIC Plan and NIPSCO's gas TDSIC Plan. For example, in the 45330 TDSIC 1 Order (at page 19), we found: "We agree with Petitioner that the netting of depreciation expense reflected in its proposal has the effect of reducing Petitioner's pre-tax return. We recently approved IPL's netting proposal as appropriately addressing the double recovery concern raised by the OUCC and found that based on the reduction to TDSIC cost recovery, no further adjustment to the WACC was required. Indeed, we commended IPL's approach. Similarly, here we find…evidence that it is not reasonable to….further effectively adjust the assets that were included in rate base in Petitioner's most recent base rate case. The TDSIC Statute addresses TDSIC costs, not rate-based asset costs. See Indiana Code § 8-1-39-7. Thus, we find Petitioner's proposed depreciation netting addresses the OUCC and….double recovery concerns and that no further depreciation adjustment is necessary. (Emphasis added.)" No additional evidence or distinguishing factors have been offered….in this proceeding, and we thus decline to reverse our prior orders…~~

~~We find no convincing evidence on the record for a change to previous Commission findings. Thus, we agree with Ms. Diaz that no further adjustment is necessary and reiterate our previous findings in Cause No. 45557, NIPSCO's most recent electric TDSIC case.~~

~~**10. Timing and Plan Update Process.** The evidence in this proceeding shows that Duke Energy Indiana has not received an order in a base rate case since June 29, 2020. Duke Energy Indiana filed its petition in this Cause on November 23, 2021. We find that this Cause was filed more than nine months after Duke Energy Indiana's last general rate case in accordance with Ind. Code § 8-1-39-9(d).~~

~~Ind. Code § 8-1-39-9(b) provides that a utility shall update its TDSIC plan at least annually. Similar to Petitioner's TDSIC 1.0 filings, Duke Energy Indiana proposed an annual TDSIC 2.0 Plan Update filing in the fall, with cost recovery filings in the spring. The Commission finds the proposed Plan Update process outlined by Duke Energy Indiana complies with Section 9(b) of the TDSIC Statute, is reasonable, and should be approved. Therefore, Duke Energy Indiana's initial filing following the issuance of this Order shall be filed under Cause No. 45647 TDSIC 1. We further note that the Commission previously approved Duke Energy Indiana's TED project in Cause No. 45647 S1. As ordered in that Cause, any costs associated with that TED project should be included in a cost recovery filing following this Order. We additionally find that any subsequent TED projects proposed by Duke Energy Indiana shall be filed in either a Plan Update or cost recovery filing following this Order.~~

11. **Confidential Information.** On November 23, 2021 and February 25, 2022, Petitioner filed motions requesting protection of confidential and proprietary information along with supporting affidavits showing the documents to be submitted to the Commission contained confidential, proprietary, competitively sensitive, and/or trade secrets as defined under Ind. Code §§ 23-2-3-2 and 5-14-3-4. On December 1, 2021, and March 4, 2022, the Presiding Officers preliminary determined that trade secret information should be subject to confidential procedures, as supported by Petitioner's affidavits. The Commission finds all such information preliminarily granted confidential treatment is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and should be held by the Commission as confidential and protected from public access and disclosure.

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

1. ~~The projects identified in~~ Duke Energy Indiana's TDSIC 2.0 Plan is denied. ~~constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2.~~

~~2. Petitioner's TDSIC 2.0 Plan is reasonable and approved.~~

~~3. Duke Energy Indiana is authorized to recover 80% of Duke Energy Indiana's six-year TDSIC 2.0 Plan costs through Standard Contract Rider No. 65.~~

~~4. Duke Energy Indiana is authorized to defer 20% of eligible and approved capital expenditures and TDSIC costs, including operations and maintenance, depreciation, property taxes, allowance for funds used during construction, and post in service carrying costs under Ind. Code § 8-1-39-9(c) as part of Duke Energy Indiana's next general rate case.~~

~~5. Petitioner's proposed process for updating the TDSIC 2.0 Plan in future TDSIC annual adjustment proceedings, and filing TDSIC rate updates, under Cause No. 45647 TDSIC-X is approved.~~

~~6.~~2. The information Petitioner filed in this Cause pursuant to motions for confidential treatment, as discussed in Finding No. 11 above, is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, exempt from public access and disclosure by Indiana law, and will be held by the Commission as confidential and protected from public access and disclosure.

~~7.~~**3.** This Order shall be effective on and after the date of its approval.

FREEMAN, HUSTON, KREVDA, OBER, 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