STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. FOR APPROVAL OF PETITIONER'S 7-YEAR PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10 AND APPROVAL OF A TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT AND DEFERRALS, PURSUANT TO IND. CODE § 8-1-39-9, AND APPROVAL OF CERTAIN REGULATORY ASSETS	)	CAUSE NO. 44526

INDUSTRIAL GROUP'S SUBMISSION OF PROPOSED ORDER

The Duke Industrial Group, by counsel, hereby submits its Proposed Order in the above captioned matter.

Respectfully submitted,

LEWIS & KAPPES, P.C.

/s/ Timothy L. Stewart
Timothy L. Stewart, Atty No. 2189-49
Jennifer W. Terry, Atty No. 21145-53-A

LEWIS & KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282-0003
Telephone: (317) 639-1210
Facsimile: (317) 639-4882
Email: TStewart@Lewis-Kappes.com
JTerry@Lewis-Kappes.com

CERTIFICATE OF SERVICE

The undersigned counsel hereby certifies that a copy of the foregoing document was served via electronic mail, hard copies available upon request, this 5th day of March, 2015, upon the following:

Kelley A. Karn Casey M. Holsapple DUKE ENERGY BUSINESS SERVICES LLC 1000 East Main Street Plainfield, IN 46168 Kelley.karn@duke-energy.com Casey.holsapple@duke-energy.com Anne E. Becker LEWIS & KAPPES, P.C. One American Square, Suite 2500 Indianapolis, IN 46282-0003 abecker@lewis-kappes.com J. David Agnew LORCH NAVILLE WARD LLC 506 State Street PO Box 1343 New Albany, IN 47151-1343 dagnew@lnwlegal.com Jennifer A. Washburn CITIZENS ACTION COALITION 603 East Washington Street, Suite 502 Indianapolis, IN 46204 jwashburn@citact.org Robert K. Johnson 2454 Waldon Drive Greenwood, IN 46143 rjohnson@utilitylaw.us Nikki G. Shoultz, Esq. BOSE MCKINNEY & EVANS, LLP 111 Monument Circle, Suite 2700 Indianapolis, IN 46204 nshoultz@boselaw.com	A. David Stippler Randall Helmen Jeffrey Reed OFFICE OF UTILITY CONSUMER COUNSELOR 115 West Washington Street, Suite 1500 South Indianapolis, IN 46204 dstippler@oucc.in.gov rhelmen@oucc.in.gov jreed@oucc.in.gov infomgt@oucc.in.gov Michael B. Cracraft HACKMAN HULETT & CRACRAFT, LLP 111 Monument Circle, Suite 3500 Indianapolis, IN 46204 mcracraft@hhclaw.com Randolph G. Holt PARR RICHEY OBREMSKEY FRANDSEN & PATTERSON LLP % Wabash Valley Power Association, Inc. 722 North High School Road Indianapolis, IN 46214 R_holt@wvpa.com Jeremy L. Fetty PARR RICHEY OBREMSKEY FRANDSEN & PATTERSON LLP 201 North Illinois Street, Suite 300 Indianapolis, IN 46204 jfetty@parrlaw.com John Watson 122-3 South Meridian Street PO Box 430 Sunman, IN 47041 j.h_watson64@yahoo.com

Charles R. Mercer, Jr. CenturyLink 5320 Singleton Street Indianapolis, IN 46227-2065 Charles.r.mercer@gmail.com	Kurt J. Boehm, Esq. Jody Kyler Cohn, Esq. Boehm, Kurtz & Lowry 36 East Seventh Street, Suite 1510 Cincinnati, OH 45202 KBoehm@BKLlawfirm.com JKylerCohn@BKLlawfirm.com John P. Cook, Esq. John P. Cook & Associates 900 West Jefferson Street Franklin, IN 46131 John.cookassociates@earthlink.net Kevin Higgins Energy Strategies, LLC Parkside Towers 215 South State Street, Suite 200 Salt Lake City, UT 84111 khiggins@energystrat.com

/s/ Timothy L. Stewart
Timothy L. Stewart

Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282-0003
Telephone: (317) 639-1210
Facsimile: (317) 639-4882

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BY THE COMMISSION:
Angela Rapp Weber, Commissioner
Jeffery A. Earl, Administrative Law Judge

On August 29, 2014, Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Company" or "Petitioner") filed its Verified Petition requesting the Indiana Utility Regulatory Commission ("Commission") approve its 7-year plan for eligible transmission, distribution and storage system improvements ("T&D Plan") pursuant to Ind. Code § 8-1-39-10. In addition, Petitioner requested approval of a Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment and deferrals pursuant to Ind. Code § 8-1-39-3, and approval of certain regulatory assets. Duke Energy Indiana filed its case-in-chief testimony on August 29, 2014.

Petitions to Intervene were filed and subsequently granted by the Commission for the following: Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"); Citizens Action Coalition of Indiana, Inc. ("CAC"); Duke Energy Indiana Industrial Group ("Industrial Group"); Steel Dynamics, Inc. ("SDI"); Indiana Municipal Power Agency ("IMPA"); Wabash Valley Power Association, Inc. ("WVPA"); The Kroger Co., also doing business as Scott's Food Stores and Owen's Markets ("Kroger"); The Environmental Defense Fund ("EDF"); Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC ("CSN"); and the Indiana Telecommunications Association ("ITA").

A field hearing was held in this Cause on November 12, 2014, at 6:00 p.m. in the Duke West Room of the Bloomington/Monroe County Convention Center, Bloomington, Indiana.

On November 13, 2014, EDF filed testimony with the Commission. On November 14, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC"), CAC, Industrial Group, SDI, WVPA, and CSN filed testimony with the Commission. On December 12, 2014, Duke Energy Indiana filed rebuttal testimony.

Pursuant to public notice given and published as required by law, proof of which was incorporated into the record, a public evidentiary hearing was held in this Cause beginning at 9:30 a.m. on January 26, 2015 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner, the OUCC, Nucor, CAC, Industrial Group, SDI, IMPA, WVPA, Kroger, EDF, and CSN appeared by counsel and participated at the hearing.

Prior to the evidentiary hearing, CAC filed a motion to strike the direct testimony of Duke witness Brian Davey. Duke has designated Mr. Davey as a non-expert, "skilled" witness to avoid providing, in discovery, certain documents Mr. Davey had reviewed while preparing his testimony. CAC argued that Mr. Davey's opinions were inadmissible because they were based on facts that were not within his personal knowledge. At the evidentiary hearing, the presiding officers denied CAC's motion without discussion.

At the evidentiary hearing, Duke Energy Indiana offered its direct testimony into the evidentiary record. The direct testimony of Brian P. Davey was admitted over the renewed objection by CAC that the testimony contained improper opinion testimony by a witness designated as a "non-expert." Duke's remaining direct testimony was admitted without objection.

Neither the OUCC nor any intervenors cross examined any Duke Energy Indiana witness. At the conclusion of Duke Energy Indiana's direct evidence, the OUCC, CAC, Nucor, Industrial Group, SDI, CSN, and Kroger (collectively, "Joint Movants") orally moved to dismiss Duke Energy Indiana's Petition pursuant to Trial Rule 41(B) of the Indiana Rules of Trial Procedure. Duke Energy Indiana provided an oral response to the motion at the evidentiary hearing, and subsequently filed a written response to Joint Movants' oral motion to dismiss. On January 27, 2014, the Presiding Officers denied Joint Movants' motion to dismiss. Joint Movants appealed the Presiding Officers' ruling to the full Commission. The four present members of the Commission unanimously upheld the decision of the Presiding Officers.[1]

The Industrial Group, SDI, EDF, and WVPA offered their evidence, which was admitted into the record in this proceeding without objection. Both the Industrial Group and SDI submitted revised testimony from that which was prefiled on November 14, 2014. The OUCC, CAC, and CSN did not offer their prefiled evidence into the evidentiary record. Due to these revisions, Duke Energy Indiana made significant revisions to its prefiled rebuttal testimony. The revised rebuttal testimony was admitted into the evidentiary record without objection. Nucor, Kroger, IMPA, and ITA did not prefile testimony or offer any testimony into the record. No members of the general public appeared or sought to testify at the evidentiary hearing.

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

1. <u>Notice and Jurisdiction</u>. Due, legal, and timely notice of the evidentiary hearing in this Cause was given as required by law. Petitioner is a public utility within the meaning of that term as defined in Ind. Code § 8-1-2-1, and is subject to regulation by the Commission in the manner and to the extent provided for by the laws of the State of Indiana, including the Public

[1] Vice Chair Carolene Mays-Medley was unavailable to attend the hearing in person due to a prior obligation.

Service Commission Act, as amended. Accordingly, the Commission has jurisdiction over Duke Energy Indiana and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Duke Energy Indiana is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Duke Energy Indiana is engaged in rendering retail electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

3. **Relief Requested in this Cause.** Petitioner is requesting approval of its proposed T&D Plan in accordance with Ind. Code § 8-1-39-10. Specifically, Petitioner requests: (1) a finding that the projects contained in its T&D Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2; (2) a finding of the best estimate of the cost of the eligible improvements was included in the T&D Plan; (3) a determination that the public convenience and necessity require or will require the eligible improvements included in the T&D Plan; and (4) a determination that the estimated costs of the eligible improvements included in the T&D Plan are justified by incremental benefits attributable to the T&D Plan. If and to the extent the Commission determines that the T&D Plan is reasonable, Duke Energy Indiana requests the Commission approve the T&D Plan and designate the eligible transmission, distribution and storage system improvements included in the T&D Plan as eligible for Transmission, Distribution and Storage System Improvement Charge ("TDSIC") treatment in accordance with Ind. Code § 8-1-39-9. Petitioner is requesting approval of its ratemaking proposals, including the T&D Infrastructure Improvement Cost Rate Adjustment, Standard Contract Rider No. 65 ("T&D Rider" or "Rider 65"), for recovery of 80% of the T&D Plan costs, and deferral with carrying costs of 20% of the T&D Plan costs for subsequent recovery in Petitioner's next general retail electric base rate case, and approval of regulatory assets for the deferred amounts and for certain metering investments, among other requests. Finally, Petitioner is requesting approval of its proposed process for updating the T&D Plan in future semi-annual proceedings.

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

Ms. Birmingham-Byrd provided an overview of Duke Energy Indiana's case-in-chief. Ms. Birmingham-Byrd testified that Duke Energy Indiana has invested in its transmission and distribution infrastructure over the years at a steady rate to provide reliable and safe service to its customers, the system continues to age and many components are in need of repair, replacement, and modernization. She testified that in developing a 7-year T&D Plan, the Company has focused on improvements that maintain the reliability that its customers value and expect and that modernize the T&D grid to enable additional value-added customer services and options now and in the future. She stated that customer satisfaction survey results, such as the J.D. Power surveys of electric utility residential and business customers and the Company's own internally-developed surveys reveal that reliability is job No. 1 for electric service providers. In addition, consumers have come to expect more, better, and faster information about all the services and products they consume. They want communication in the formats they prefer, such as mobile apps, texts, and web portals. Utilities need to fully enter the digital age in all aspects of their systems – from the meter, over the transmission and distribution lines, through substations, to the back-office IT information systems and data management systems. She testified that survey results also show that utilities that have fewer and shorter outages also have an improved customer experience. This underpins the importance of a smarter and more reliable system. Ms. Birmingham-Byrd testified that Petitioner's 7-year T&D Plan contains investments that will allow the Company to reduce unplanned outages, pinpoint fault locations faster, reduce the scope of customer outages, reduce the length of customer outages, and, importantly, provide better, faster, more accurate information to customers about the cause of the outage and the expected time of restoration. The Company has also included grid modernization components that will provide customers with better insight into their customer usage, ease turn on / turn off orders, and create efficiencies and cost savings.

Ms. Birmingham-Byrd testified that the 7-year T&D Plan estimates are the Company's best estimates of the costs at this time; however, by their very nature, these estimates are preliminary and high level until Petitioner gets closer in time to the expected expenditures when project parameters can be identified with more specificity and detailed engineering work completed to enable a better cost estimate. She testified that even the more detailed year-one estimated costs provided in Mr. Atkins' Confidential Exhibit B-4 are subject to change on a project or component basis as the T&D Plan develops, engineering progresses, and contracts are entered into for labor, materials and construction. She explained that the Company plans to manage the overall costs of the T&D Plan to the estimated annual levels, so that, in aggregate, the annual rate impact will be relatively consistent with its 7-year T&D Plan proposal. She stated that the Company will also provide updated projects and cost estimates annually in one of its semi-annual filings, so stakeholders and the Commission are aware of any changes.

Ms. Birmingham-Byrd testified that system reliability is a core value that will be maintained by the T&D Plan. Replacing aging infrastructure, targeting degrading components, upgrading equipment, improving poor performing circuits – all of this will benefit customers through maintaining a safe, reliable T&D system. The modernization components of the T&D Plan will enable the deployment of enhanced equipment providing more timely and accurate information about outages to customers. Customer outages can be pinpointed and restored more efficiently through the distribution automation and advanced metering investments. She stated that near term customer benefits include hourly interval usage data (next day) through a unique website portal, allowing customers to better understand their energy usage and save energy, and the convenience of remote turn off / turn on for customer moves. Future advanced metering benefits could include such products and services as: time-differentiated peak pricing rates; pay as you go billing options; pick your own due date options; and customer usage alerts. She stated that Duke Energy Indiana proposes an advisory collaborative process with key stakeholders to assist in developing these future rate, product and service offerings as the advanced metering solution is rolled-out to customers.

Duke Energy Indiana also takes its cybersecurity responsibility seriously. Ms. Birmingham-Byrd testified that the Company has a team focused on cybersecurity protection and detection. The Company will ensure that the investments made as part of its 7-Year T&D Plan are compliant with its most up-to-date cybersecurity protections.

Ms. Birmingham-Byrd also provided testimony concerning the reasonableness of the overall rate impact of the T&D Plan. Ms. Birmingham-Byrd testified that the Company is keenly aware of the need to balance rate impacts with the need and value of the T&D Plan. As a result, the average annual rate impact is approximately 1%, below the 2% annual cap permitted by Senate Enrolled Act 560 (the "Act").

Ms. Birmingham-Byrd provided significant testimony regarding the economic development impacts on the State of Indiana. Ms. Birmingham-Byrd explained that economic development is one of the enumerated purposes of the Act and Duke Energy Indiana's T&D Plan focuses on economic development in two ways. First, the T&D Plan includes an economic development plan component that is focused on providing needed site improvements for new or existing customers. In turn, these new or existing customers will be providing new jobs or investment to the State of Indiana. Secondly, the Company has estimated the economic development impact of the Duke Energy Indiana T&D investments contained in the T&D Plan. The proposed 7-Year T&D Plan is estimated to create or support an estimated average of 2,700 jobs per year for each of the 7 years of the T&D Plan (or 840 jobs per year in Indiana). These jobs include both direct jobs and indirect or induced jobs that are created or supported by the T&D Plan investment. The T&D Plan is also estimated to produce about $184 million in additional state and local tax revenue. She stated that the direct jobs created from this investment will be a mix of contractor and direct employee hires, and could include construction and maintenance, engineering, project management, operating and other technical support positions. Further, the Company's contracting strategy encourages contractors to include local and diverse talent in their contracted workforce.

Russell Lee Atkins, Vice President Design Engineering and Construction Planning – Midwest, provided an overview of Duke Energy Indiana's transmission and distribution system, explained in detail the overall goals of the T&D Plan, summarized the Distribution and Other T&D projects, provided cost estimates for those projects, and explained the final results of the Black & Veatch risk profile analysis. Mr. Atkins testified that the Company's T&D Plan allows the Company to address more aggressively its aging infrastructure and brings the system into the 21st century. He testified that Petitioner owns and operates approximately 5,800 miles of transmission lines[2] and approximately 12,000 miles of distribution lines in Indiana, in addition to about 400 substations. The Company has approximately 810,000 customers in Indiana, most of whom still have electro-mechanical meters. He testified that a significant portion of the Company's transmission and distribution system was constructed in the 1960s, 1970s, and 1980s, and is nearing or has exceeded its original life expectancy. He testified that the Company hired Black & Veatch to conduct a system risk analysis which enabled the Company to prioritize projects that would strategically lower the risk profile of the T&D system.

Mr. Atkins provided summaries of each of 40 project categories included in Petitioner's T&D Plan. Pet. Ex. B-1. For each project included in the T&D Plan, the summaries provided: (i) the 7-year budget for the project; (ii) the first year budget for the project; (iii) a description of the project scope; (iv) the current and desired state of the project; (v) the project benefits; and

[2] Although Duke Energy Indiana operates and maintains the entire transmission system, Wabash Valley Power Association and Indiana Municipal Power Agency share in the operation costs of the transmission system. The T&D Plan outlined in this filing represents Duke Energy Indiana's share of transmission investment.

(vi) the risks associated with not doing the project. Confidential Exhibit B-4 includes more detailed information on the project scope for the project categories included in year one of the T&D Plan including the number and location of individual planned projects. He stated that as time goes on, the Company will further refine the cost estimates for each year of the T&D Plan in its semi-annual T&D Rider No. 65 filings.

Mr. Atkins provided descriptions of each of the distribution projects included in the T&D Plan. Mr. Atkins testified that each of these projects support continued reliable system performance and increases system functionality while at the same time promoting economic development and the development of a better customer experience.

Mr. Atkins explained that the distribution projects will address aging infrastructure while improving system functionality and providing additional customer information in a timelier manner. By replacing this equipment, Duke Energy Indiana is replacing older infrastructure while ensuring enhanced performance of the distribution system. He stated that the projects will provide new functionality to the distribution system including real-time communication status, fault location data, self-healing networks and remote operations.

Mr. Atkins provided the 7-year estimated cost of the T&D Plan, with a total T&D Plan investment of $1,868,050,000. He testified that the Company has significant estimating experience with projects such as these. Many of the projects are accelerations of existing programs or projects the Company performs annually. Others are new technologies for Duke Energy Indiana, but the Company relied on similar investments in other Duke Energy jurisdictions for its cost estimating. Mr. Atkins testified that the estimates reflect a reasonable view of the expected costs at this time. The Company also engaged Black & Veatch to review its cost estimates for reasonableness, and this independent review confirmed the Company's estimates. He explained that the Company would expect changes and refinements to the cost estimates contained in the T&D Plan and its proposed semi-annual Rider review process will allow Petitioner to timely inform the Commission and stakeholders of any significant changes. He stated that more detailed estimates and project scope were provided for the first year of the Plan, with additional detail being provided annually on the upcoming year in its semi-annual T&D Rider proceedings.

In his testimony and exhibits, Mr. Atkins provided cost estimates and descriptions for the communication replacement project, distribution operations center renovations, the Envision Center, the Economic Development Site Readiness program, the T&D control room renovations and upgrades, the personal mobile device communication project, the mobile deployment and innovation project and the Transmission & Substation Asset Performance Center project. He testified that the communication replacement project included in this category is a high level estimate, as a technology solution has not been selected. He stated that over the next two years the radio replacement plan will be continually reviewed and updated to reflect the most current state of the program and reflect the best technological solution for the communication needs of the business. He testified that this project is targeted for 2017/2018 and updates will be provided annually in one of Petitioner's semi-annual T&D Rider filings. Mr. Atkins testified that the distribution operation center renovations program is directed to modify the Company's current multifunction facilities to be more purpose-designed and to support a much more technologically-dependent distribution system work force. Mr. Atkins also described the proposed Envision Center. He explained that this would be an educational center used for community outreach so that the Company can engage the public, schools, universities, community groups, local governmental officials and others about the benefits of its grid modernization efforts. He stated that this is a unique opportunity for the Company since this will be the first full-scale roll-out of distribution automation and Advanced Metering Infrastructure technology in the State of Indiana by a large electricity supplier. He testified that the Company currently plans to locate the Envision Center on or near the Duke Energy campus in Plainfield, Indiana to allow centralized access for much of its service territory. Mr. Atkins also described the economic development site readiness program which would spur new companies to locate or existing companies to expand in Indiana. He explained that the project would be used to fund facility modifications, alternate source needs or other T&D system improvements that would be beneficial to the promotion of economic growth in the State of Indiana. He stated that this proactive approach to site-readiness capacity upgrades and a redundant networked system will help draw these customers to Indiana. These funds will be used as new customer sites or expansions are identified and will be limited to investments in the T&D system. Mr. Atkins testified that the transmission and distribution control center upgrade project will advance these facilities to current state-of-the-art support centers that complement the capabilities of the modern electric grid. This project will enable fault location, mobile data and dispatch, and increased customer information about distribution grid performance. Mr. Atkins testified that the real time customer Personal Mobile Device ("PMD") communication project includes the installation of a customer communications software system designed to provide customers information relevant to the T&D systems, such as outage notifications, estimated time of restoration or outage causation. He stated that this system will tie with systems such as outage management, customer billing, etc., and proactively communicate with customers based on what they have requested and the preferred method of communication. Mr. Atkins testified that the mobile deployment and innovation project involves deployment of mobile data terminals to all distribution field workers to improve real-time dispatch, outage status and event support. It will allow real-time two-way communication with first responders and T&D field workers. This improved information flow between dispatch and field workers will allow for more efficient customer order work and outage restoration. Mr. Atkins described the transmission and substation asset performance center project stating that it involves development of a Transmission & Substation Asset Performance Center which allows for enhanced analysis and monitoring of outages and events on the delivery system. He stated that this will provide for a more efficient system and should reduce outage restoration time.

Mr. Atkins explained that the Other T&D Projects have been included to support the changing infrastructure needs of a modern distribution and transmission system and a technologically mobile workforce and to encourage economic development. These projects are critical to support the increasing amount of infrastructure capable of remote operation and data gathering, as well as back office integration.

Mr. Atkins testified that the vegetation management components of the T&D Plan will increase the reliability of Duke Energy Indiana's transmission and distribution system and include: (i) a capital program directed at the removal of hazard trees which pose a risk of striking electric facilities; (ii) facility relocation or right-of-way acquisition for facilities experiencing high frequency vegetation-related outages; and (iii) incremental O&M required to bring the vegetation management program in-line with an industry-standard five-year trim cycle. He explained that the first two programs are existing capital projects that will be accelerated as part of the T&D Plan. The O&M vegetation management project is also an existing project. However, the project size was determined by comparing vegetation expense in the last rate case relative to the current annual spend required to implement the five-year trim plan.

Mr. Atkins testified that the Integrated Volt-VAR Controls ("IVVC") project provides real-time monitoring and the ability to make voltage adjustments to the distribution system, which is estimated to ultimately reduce overall system voltage by approximately 2% on impacted circuits. He stated that this results in a 1% load reduction on average for impacted circuits, providing cost savings to customers. The customer savings is in both kWh for the impacted circuits and fuel consumed, which provides benefits to all customers. He stated that customers will see this benefit through lower electric bills as the savings flow through the fuel adjustment clause rider. In addition, IVVC can be used for peak reduction during high usage conditions. Mr. Atkins testified that the Company completed a business case cost / benefit analysis which demonstrated that the IVVC project is estimated to provide a benefit of $240 million over a 20-year life.

Mr. Atkins also described how Duke Energy Indiana will update the Commission and intervenors if there are changes to the T&D Plan. He testified that the Company plans to make updates to its 7-year transmission plan annually. The Company will also update its risk analysis with completed projects and an updated assessment of the future needs for upcoming years. He stated that this risk model will be used to produce future year capital plans and will be submitted for review to the Commission, OUCC and intervening parties annually in one of its semi-annual T&D Rider proceedings.

Mr. Atkins testified that public convenience and necessity require each component of the T&D Plan. The Plan supports a reduction of operational risk through replacement of aging infrastructure. Furthermore, the T&D Plan improves the operational efficiency of the Company's transmission and distribution system. He testified that the T&D Plan addresses and improves upon the overall customer experience and will enable a number of customer benefits and programs in this filing and in future years. Mr. Atkins further testified that the estimated costs of the T&D Plan justify the incremental benefits of the Plan. He stated that the projects and programs included in the T&D Plan are reasonable, necessary, and justified by significant reliability and modernization benefits.

Theodore H. Kramer, Director Transmission Engineering, provide testimony on the transmission projects included in the T&D Plan. He testified that Duke Energy Indiana operates a transmission system consisting of approximately 5,800 miles of transmission lines operated at 69 kV to 345 kV and about 400 transmission substations which include distribution assets.[3] He testified that Duke Energy Indiana has a significant number of transmission assets that are approaching or have exceeded their estimated physical service lives. He stated that there are 12

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[3] Although Duke Energy Indiana operates and maintains the entire transmission system, Wabash Valley Power Association and Indiana Municipal Power Agency share in the operation costs of the transmission system. The T&D Plan in this proceeding represents Duke Energy Indiana's share of transmission investment.

transmission categories within the Company's T&D Plan targeted at replacing, rebuilding, and modernizing these assets. Mr. Kramer testified that Duke Energy Indiana provided an exhibit that summarized the details of each transmission project, the customer benefits of each project, and the risks of failing to do the projects. Pet. Ex. B-1. Mr. Kramer testified that customers will see improvements made to the transmission system through improved reliability and improved telemetry through relay replacement and two-way communication. He stated that investments in the 69 kV transmission system will reduce the number of system faults, improving reliability through a reduction of the frequency and duration of service interruptions and voltage sags.

Mr. Kramer described the planned transmission projects for the first year of the Plan. He stated that these projects were selected from lists of candidate equipment or projects based on a combination of factors including identified condition or age of the equipment, feedback from maintenance personnel, project efficiencies and savings from combining engineering or labor from several projects, coordinating project schedules to correspond with planned outages or other planned work, and the individual risk assessment scores from the Black & Veatch risk study. He testified that the most significant first year projects in the Plan are as follows:

> (1) Transmission Relay Upgrade – Tiers I and II. Installation of new microprocessor-based relays will include additional functionality including full two-way communication and the ability to provide distance to fault which will allow improved restoration following an outage. They will also provide increased immunity to geomagnetic induced currents to avoid potential undesirable operations. Mr. Kramer testified that the new relays will conform to NERC cybersecurity standards.
>
> (2) Transmission Breaker Replacement. This project entails the replacement of obsolete oil breakers, high-volume SF6 gas breakers, and other high maintenance gas breakers with new gas breakers that have greater interrupting capability, improved reliability, and reduced environmental issues from oil spills and SF6 gas discharge.
>
> (3) 69 kV Circuit Integrity Improvement. This project entails rebuilding selected transmission lines or line sections which contain aged or deteriorating components such as wood poles and cross-arms, insulators, conductors, and static wires to improve the overall reliability of the 69 kV circuits.
>
> (4) Aluminum H Structure Replacement. This project entails replacing self-supporting 345 kV aluminum H-frame structures with new steel poles to decrease exposure to failures.

Mr. Kramer testified that these selected projects constitute $580.5 million of the overall approximate $753 million transmission category 7-year expenditures of the T&D Plan. He stated that the cost estimates were developed from internal estimating procedures and validated by Black & Veatch. He testified that the cost estimates are reasonable and will evolve as more information becomes available on the specific project being constructed in any given year. Mr. Kramer further testified that the Company needs flexibility within its T&D Plan to identify new or changing needs of the delivery system as the program progresses. The Company will update the transmission plan on an annual basis defining future years based on risk reduction and system performance improvement providing the best utilization of future capital.

Donald L. Schneider, Jr., Director Advanced Metering provided an overview of the Advanced Metering Infrastructure ("AMI") proposal. Mr. Schneider discussed Duke Energy Indiana's proposed implementation of an advanced metering solution across its Indiana service territory, which is estimated to include approximately 817,000 advanced meters and associated communications and IT infrastructure. Mr. Schneider testified that the project consists of a four-year phased deployment for most of the Company's residential and commercial customers. This will not include meter replacement for larger commercial and industrial customers that already have an advanced metering solution. Mr. Schneider testified that the Company plans to collect interval kilowatt-hour ("kWh") usage on all meters for billing purposes as well as time tagged event and alert data such as tamper alerts for more efficient theft detection.

Mr. Schneider testified that the overall AMI metering solution includes advanced meters, a two-way communication network, and central computer systems. He explained that the Company will install a neighborhood area network ("NAN") to create the two-way communications path to the advanced meters. The NAN will use flexible mesh networks to establish an optimized communication path. He explained that collection point devices aggregate the communications from all advanced meters with a NAN and communicate the information over a Wide Area Network ("WAN") to the central computer systems, and they also communicate commands, firmware/program updates, and instructions from the central computer systems out to the advanced meters within a NAN. The WAN is the two-way communication network used to move data and instructions between the collection points and the central computer systems. He testified that the Company will utilize a virtual private network over a public cellular network in Indiana as its WAN. Mr. Schneider also described the central computer systems of the AMI solution.

Mr. Schneider identified the three vendors the Company plans to utilize for the AMI project – all considered leaders in their respective industries. He stated that the Company issued a request for quotes to the leading AMI solution vendors within the United States for bid proposals. After evaluation of the proposals, the Company concluded Itron was best aligned with the Company's overarching grid strategy and architectural guidance. He also explained that there has been a general shift in the electric utility industry over the past six to eight years away from installing Automated Meter Reading ("AMR") solutions, which requires a drive-by meter read each month. He stated that since Duke Energy Indiana has not previously invested in AMR, making the switch directly from walk-by meters to the increased functionality and cost savings of an AMI solution was the better choice.

Mr. Schneider testified that deployment for the AMI meters and communications equipment will occur over the first four years of the seven-year T&D Plan. He testified that Duke Energy has experience deploying AMI meters in other jurisdictions. Duke Energy Ohio plans to complete its AMI deployment in 2014 and AMI meters are being incrementally rolled out in North Carolina, South Carolina, and Florida. Duke Energy Indiana's proposed technology is not only proven across the industry, but specifically proven by Duke Energy in other jurisdictions. He testified that each service territory presents its own challenges, and Duke Energy Indiana will benefit from learned lessons in those areas.

Based on previous experience deploying AMI in other service territories, he testified that the Company anticipates deploying the AMI technology by zones. Through multiple outreach attempts, customers are informed of the upcoming installation and have ample time to reach out to the Company if they have any questions that are not answered in the literature provided. Once a customer's meter is certified, they receive a notice informing them that their interval usage data can be accessed via their customer web portal. Mr. Schneider testified that Duke Energy Indiana is committed to using best practices identified through the Company's deployments in several states and to being responsive to customer concerns, while creating the least amount of disruption to the customer during deployment.

Mr. Schneider testified that as the AMI metering solution is implemented, the Company will follow IT security policies that are based upon National Institute for Standards and Technology ("NIST") guidelines for securing Smart Grid assets and risk management. The data and systems associated with every component of the AMI metering solution are secured against both internal and external security threats. He stated that during and after implementation of the AMI solution, periodic audits and security penetration tests will be performed to ensure the appropriate policies have been applied to defend the potentially affected systems. Mr. Schneider also testified that customer privacy is of the utmost concern to Duke Energy Indiana and the Company has privacy policies in place to protect customer information.

Mr. Schneider described the changes customers will see in their service after the new metering solution is installed, including: (1) the ability to view the previous day's hourly interval usage data via the Company's web portal; (2) meter reads through the AMI communication network rather than walk-by meter reads or estimated bills; (3) remote activation and deactivation of service; and (4) the ability for Duke Energy Indiana to better identify isolated outages more readily and restore service more efficiently. Mr. Schneider testified that the AMI metering solution could enable such future offerings as dynamic pricing, flexible billing and alternative payment options. He stated that the Company proposes that these future offerings be developed in coordination with the OUCC and interested stakeholders in a collaborative fashion beginning upon approval of the T&D Plan.

Mr. Schneider testified that the Company looked at the proposed costs of the AMI metering solution and compared those costs to quantifiable benefits, such as savings from meter reading. He testified that the main quantifiable benefits arise from the elimination of monthly manual meter reads, enhanced theft detection that can be conducted without a truck roll, and the ability to conduct customer-requested service disconnects and reconnects remotely. Mr. Schneider testified that the Company proposes to work collaboratively with interested stakeholders on customer offer-related qualitative benefits as the AMI solution is rolled-out. He testified that the estimated cost for deploying the AMI solution is about $181 million over the first four years of the 7-Year T&D Plan, which includes the cost of technology components and the installation labor – including the AMI meters, communication devices/grid routers, and IT systems. He testified that based on the business case, over a 20-year period, the net present value ("NPV") of the AMI solution is estimated to be approximately $38 million. Essentially, the analysis demonstrates that over 10.4 years the investment in the advanced metering solution pays for itself. Mr. Schneider testified that the business case cost / benefit analysis demonstrates that there are quantifiable benefits that outweigh the costs of the plan. Additionally, there are qualitative benefits and future functionality that will result in further benefits.

William D. Williams, Director, Asset Management, Finance and Markets Business Line of Black & Veatch Corporation testified that Black & Veatch prepared (1) a Risk Model to identify the investment required in the replacement of aging T&D infrastructure; (2) an independent review of capital cost estimates ("Cost Analysis"); and (3) an analysis of the economic impacts ("Economic Impact Analysis") for Petitioner's T&D Plan. He explained that the Cost Analysis was used to validate the reasonableness of Petitioner's unit cost assumptions used in the T&D Plan. The Economic Impact Analysis was used to estimate economic impacts that would result from the T&D Plan.

Mr. Williams testified that the Risk Modeling was performed by analyzing and quantifying the risk reduction Duke Energy Indiana may achieve through its T&D Plan. It utilizes a risk-based planning approach, wherein the majority of the T&D Plan investments are evaluated with respect to how they reduce asset risk on Duke Energy Indiana's T&D system. He explained that this approach allows the Company to prioritize and optimize its T&D Plan to focus investment on high risk assets. Mr. Williams testified that the results of the analysis show that the proposed T&D Plan would reduce the total T&D system risk by 21% over the seven-year planning period. He stated that this is driven by significant substation and circuit risk reduction, in the amounts of 18% and 27%, respectively. Mr. Williams testified that the T&D Plan is a balanced, optimized plan that prioritizes investment for eligible transmission, distribution and storage system improvements using risk reduction as a primary objective. He stated that total T&D system asset risk is significantly reduced, providing incremental benefits to Duke Energy Indiana's system and customers.

Mr. Williams testified that Black & Veatch conducted an independent cost review of Petitioner's T&D planning capital cost estimates and estimating process, based on their knowledge and experience with similar T&D project capital cost estimates. He stated that Black & Veatch concluded that the project cost estimates and unit cost estimates reviewed were reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes. Furthermore, Mr. Williams testified that Duke Energy Indiana's cost estimating process was reasonable.

Mr. Williams testified that Black & Veatch performed a study to evaluate the economic impact of the T&D Plan resulting from project expenditures during the seven-year planning period of 2015 through 2021. He stated that the results show that the total economic impacts to the State of Indiana include 5,882 jobs created or supported, over $400 million in labor income and $1.11 billion in value-added gross domestic product ("GDP"). He explained that Black & Veatch performed this analysis using the Impact analysis for PLANning ("IMPLAN") modeling application, which is widely used in the energy industry to measure such impacts. He testified that the analysis also considered possible job losses associated with Petitioner's move to AMI metering. He stated that the results estimate that while there may be some job reductions due to the AMI investments, other job increases will occur to off-set the losses and create an overall job gain in Indiana.

Brian P. Davey, Director of Rates and Regulatory Strategy – Indiana, testified that, pursuant to Ind. Code § 8-1-39-9(d), the Company will file a rate case before the end of the proposed seven-year T&D Plan. He also stated that the T&D Plan investments were not included in the Company's last rate case, approved in May of 2004.

Mr. Davey testified that the Company is requesting authority to recover 80% of the retail jurisdictional share of the T&D Plan costs through the new proposed Rider 65, pursuant to Ind. Code § 8-1-39-9(a). He stated that this would include financing costs, depreciation and taxes, as well as O&M expenditures associated with vegetation management costs that are incremental to the O&M included in the Company's base rates related to vegetation management. In addition, the Company requests authority to accrue post-in-service carrying costs until the T&D Plan projects are included in retail rates. He testified that the Company requests deferral for subsequent recovery of the retail jurisdictional portion of the remaining 20% of allowance for funds used during construction ("AFUDC"), post-in-service carrying costs, operation and maintenance expense, 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. The Company also requests that carrying costs on these deferred costs be accrued using Duke Energy Indiana's overall weighted cost of capital as most recently approved by the Commission. He stated 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. He testified that the post-in-service carrying costs will be accrued on approved capital expenditures, including accrual on previously computed post-in-service cost amounts, from the in-service date until such costs are included in the Company's rates under Rider 65 or in base rates. The carrying costs the Company is seeking to defer are the related incremental cost of capital. Mr. Davey also testified that the retail jurisdictional portion of post-in-service operation and maintenance, depreciation, tax expense and post-in-service carrying costs will be deferred with respect to T&D Plan costs from the in-service date until the cost is included in the Company's rates under Rider 65 or in base rates.

Mr. Davey testified that the Company is requesting approval for the creation of a regulatory asset for the existing meters that will be replaced under the T&D Plan. He stated that rather than recovering the higher amount of depreciation expense over the shorter remaining lives of the meters, the Company proposes to include the difference between the depreciation expense under the current depreciation rate and what the new depreciation rate would be in a regulatory asset. He explained that the Company would move the increase in meter depreciation expense required for Generally Accepted Accounting Principles ("GAAP") to a regulatory asset account (Account 182.3) and to amortize it over the estimated remaining life of the meters (approximately 18 years) instead of on the more accelerated basis called for to comply with GAAP. He stated that the Company also requests authority to continue to earn a return on these meters whether in rate base or a regulatory asset.

Mr. Davey testified that the accounting treatment proposed is in accordance with GAAP. He also testified that the deferral and subsequent recovery of the retail jurisdictional portion of the T&D Plan costs, until they can be included in Rider 65 or base rates, is reasonable and appropriate from both a ratemaking and an accounting perspective. Mr. Davey provided the proposed Rider 65 and stated that the Company proposes to update the Rider on a semi-annual basis. He stated that the Company proposes to use a 10.5% return on common equity, as approved in the most recent general retail electric base rate case. He explained that the return on equity would remain the same but the capital structure would be updated with each filing, along with the debt costs.

Mr. Davey testified that the Company proposes to allocate the transmission, distribution excluding meters, and meters revenue requirement developed for Rider 65 to the rate groups based on the revenue requirement by rate group for these same three categories from the last retail base rate case, Cause No. 42359. He stated that costs will be billed to individual customers within a rate group based on kilowatt-hour sales except for customers served under Rate HLF, which will be based on non-coincident kW demands.

Mr. Davey testified that the Company proposes to use forecasted amounts for depreciation and property taxes, and for the vegetation management O&M based on semi-annual cut-off dates. The financing costs on invested capital would be on an actual basis based on the same semi-annual cut-off dates. He stated that the Company would true-up both of these amounts to actual levels of O&M, depreciation and property taxes and to actual kWh sales levels in subsequent Rider proceedings. Mr. Davey also testified that the Company is proposing to include the expenses incurred for retaining Black & Veatch in this proceeding, and to include the Black & Veatch costs associated with providing testimony and supporting the Company's filing in this proceeding and amortizing all Black & Veatch costs over a three-year period.

Mr. Davey testified that, although the rate impact of the T&D Plan will vary based on a number of variables, the total annual average retail rate impact compared to retail revenue for the twelve months ending June 2014 is estimated to be approximately 1% over the seven-year period. Mr. Davey stated that if an actual amount exceeds the two percent annual statutory cap, the Company requests approval to defer recovery of the costs above the cap pursuant to Ind. Code §8-1-39-14(b).

5. <u>Intervenor Testimony</u>. The Industrial Group's witness Mr. Nicholas Phillips, Jr., a Managing Principal of Brubaker & Associates, Inc., testified concerning the inability of the Commission to determine that Duke's rates would be just and reasonable after the addition to rates of the Duke TDSIC rider. Mr. Phillips outlined several facts that he believes make the statutory requirement that rates be just and reasonable undeterminable.

Mr. Phillips discussed the fact that Duke's last base rate case was filed in December 2002, twelve years ago. Mr. Phillips explained that Duke's original cost rate base at that time was $3.662 billion with approved revenues of $1.4 billion. Since that time, Mr. Phillips showed that Duke has added through trackers $3.361 billion in new rate base. He also showed that revenues had increased by more than a billion dollars to $2.5 billion. Thus, he explained that ratebase has increased by over 90% and revenues by over 80%. Mr. Phillips noted that Duke's TDSIC proposal would add more than an additional $1.8 billion in rate base.

Mr. Phillips also discussed and showed how Duke's rates had increased more, since the 2002 rate case, than the national average or Indiana average. In Duke's last rate case, Mr. Phillips showed that Duke testified that its rates were significantly below the national average and below Indiana average rates. Mr. Phillips explained how that has changed over the intervening twelve years. The fact that Duke's rates were above both the national and state average by 2013 was shown by Mr. Phillips. As he demonstrated, Duke's rates had gone up 88.9% while the national and state averages increased only 46.4% and 54.5%. Mr. Phillips also presented the fact that the rates for industrial customers had increased even more, growing by 100% to above the national average.

Mr. Phillips also showed that another area that has experienced significant change is consumption by rate class. Mr. Phillips demonstrated that Duke's 2013 MWh sales were 10% higher than in the last rate case, whereas the rate HLF sales were down 12%. Mr. Phillips testified that basing an allocation of costs today on factors determined in the last rate case, when changes of this magnitude have taken place over the last twelve years, results in over-allocations of cost to rate HLF. Mr. Phillips also stated that Duke had acknowledged that rate HLF was being allocated more costs than is reasonable and just, with Duke proposing a change to its IGCC tracker to address the reduction in customers and sales in rate HLF. Another fact Mr. Phillips demonstrated was that rate HLF has five voltage levels that should be allocated different shares of any reasonable TDSIC costs. Duke ignored the differentiation in its proposed allocation of TDSIC costs, further misallocating costs.

Mr. Phillips' stated that there were serious problems associated with implementing a rate increase sought by Duke based on 2002 data given the fact that so many key factors have changed. He explained that any approved TDSIC would become part the total charge for service which must be just and reasonable under Ind. Code §8-1-2-4. Mr. Phillips stated that given the many things that have intervened over the past twelve years, whether Duke's charge for service would be just and reasonable after adding the TDSIC was called into question. Mr. Phillips recommended that the Commission deny Duke's requested relief in its entirety.

SDI's witness Mr. Kevin Higgins, Principal in the firm of Energy Strategies, LLC, testified that Duke Energy Indiana's TDSIC cost allocation proposal should be rejected because it would produce unreasonable and inequitable results. He stated that it would improperly and unreasonably recover distribution system investment costs from transmission voltage customers that do not use the distribution system. Mr. Higgins recommended that customers taking service from the common *transmission* system should not be assigned any Rider 65 revenue requirement responsibility for costs related to the *distribution* system. In addition, HLF customers taking service from the *bulk transmission system* should not be assigned Rider 65 revenue requirement responsibility for costs related to the *distribution system* either, except for the small allocation of step-down substation costs these customers received in the 2003 cost-of-service study. In the case of HLF, the share of Rider 65 revenue requirement allocated to HLF for recovering distribution system costs should be recovered almost exclusively from those HLF customers that are served at distribution system voltage. This principle should extend to the LLF rate schedule as well. Accordingly, almost none of the costs categorized by the Company as "distribution minus meters" that are allocated to HLF and LLF should be recovered from transmission voltage customers, but instead virtually the entirety of this cost category that is allocated to HLF and LLF should be recovered from HLF and LLF customers taking service at secondary and primary voltage.

The Industrial Group's witness Mr. Michael Gorman, a Managing Principal of Brubaker & Associates, Inc., testified regarding his suggested estimate of Duke Energy Indiana's current market cost of equity, or required return on equity. Mr. Gorman recommended the Commission award a return on common equity ("ROE") of 9.30%, which is at the midpoint of his recommended range of 9.00% to 9.60%.

Mr. Gorman's review of credit outlooks and stock price performance concluded that the market continues to embrace the regulated utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities. He testified that the number and magnitude of total revenue recovered under Duke Energy Indiana's regulatory tracker mechanisms are material, and provide Petitioner much stronger cost recovery assurance, and therefore reduced investment risk. He stated that the demand for low-risk investments will provide funding for regulated utilities in general. Mr. Gorman testified that Duke Energy Indiana has credit ratings of "BBB+" from both Standard & Poor's and Fitch, and "A3" from Moody's. All three credit rating agencies rate Duke Energy's credit outlook as "stable" and recognize the strong regulatory mechanisms used in Indiana to support Duke Energy's strong investment grade quality, and minimize its cost recovery risk.

Mr. Gorman testified that Duke Energy's last rate case setting base rates was in a PSI rate proceeding (Cause 42359) in 2004 in which it was awarded a 10.5% return on equity. This was based on a 2002 test year and Duke Energy's embedded cost of debt was 6.37%. Mr. Gorman testified that Duke Energy's capital market costs have declined since its last base rate case, with its cost of capital 75 to 150 basis points lower now than it was in 2004. He stated that this decline does not reflect the significant reduction in Duke Energy's investment risk attributable to the new tracker mechanisms that have been implemented since 2004. He testified that because Petitioner now recovers over 35% to 50% of its rate base in tracker mechanisms, its investment risk has been significantly reduced in this case relative to the last base rate case.

Mr. Gorman described the methods used to estimate Duke Energy Indiana's cost of common equity, including the following models: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk premium model; and (5) a Capital Asset Pricing Model ("CAPM"). Mr. Gorman testified that he applied these models to a group of publicly traded utilities that have investment risk similar to Duke Energy Indiana's. Mr. Gorman testified that based on his analyses, his recommended return on common equity of 9.30% is the midpoint of his estimated range of 9.00% and 9.60%. The high-end of his estimated range is based on his risk premium studies, and the low-end is based on his DCF studies. He stated that the midpoint of this range reflects current market capital costs, increased interest rate risk in the current market due to Federal Reserve policies and other factors, and represents fair compensation to Duke Energy's investors for the total investment risk of its regulated utility.

WVPA witness Mr. Gregory Wagoner, Vice President Transmission Operations and Development, testified that WVPA is supportive of Duke Energy Indiana's T&D Plan. WVPA provides electric service to approximately 335,000 retail customers. Mr. Wagoner testified that WVPA and its members have experienced an increasing trend in the number and duration of transmission related outages due to the aging transmission infrastructure. He stated that on average over the past five years transmission related outages account for 35% to 40% of total outage duration on distribution cooperatives systems. Mr. Wagoner testified that increased investment in the Joint Transmission System[4] will reduce the number and duration of transmission related outages thus improving overall reliability to WVPA's distribution cooperative members and their retail customers. He testified that in connection with Petitioner's 7-year Plan, WVPA estimates that it will invest approximately $100 million in the Joint Transmission System over the next seven years to improve reliability and accommodate additional load growth. Mr. Wagoner testified that WVPA and its members have invested millions of dollars in distribution automation and self-healing on the members' distribution systems circuits over the past several years. Twenty-two of WVPA's members currently have AMI advanced electric meters deployed. He also stated that Duke Energy Indiana has offered to work with WVPA and its members to discuss the 2016 work plan and help identify projects that will directly improve the transmission service provided by Duke Energy Indiana.

EDF witness Mr. Dick Munson, Midwest Director – Clean Energy, testified that any data relating to demand, power quality, availability, voltage, frequency, current, power factor, or other information generated by the meter should be made available to both the customer and the utility. He also stated that customers should have access to their retail electric consumption data in as short intervals as possible, with 15-minute intervals recommended, but never in intervals greater than one hour. He testified that customer energy efficiency savings information is quantifiable when customers are provided with real-time access to their energy usage, with recommendations to change behavior, which could reduce their energy consumption up to 12%. Mr. Munson testified that Petitioner should do more to provide timely usage information to customers. He recommended that Duke Energy Indiana supplement its filing to include cost-benefit analyses for: (1) providing data access directly from the meter so customers could connect in-home devices (such as Home Energy Displays, in-home monitors, smart thermostats, energy hub devices) to see, understand and take charge of their electricity usage immediately; (2) providing data access to customers and their designated third-parties through standards-based data protocols (such as Green Button Download, Green Button Connect My Data, ESPI) through the internet, so customers can easily use third-party web or mobile applications or join innovative new business models that require quick and easy access to metering data; and (3) providing smart thermostats and in-home monitors to customers, which would allow them to see their energy usage in real time. Mr. Munson testified that if the study shows that it would be cost-effective to do so, the Company should include smart thermostats, in-home monitors, and Green Button-Connect My Data features in its deployment plan. Mr. Munson also recommended

[4] In addition to being a transmission customer WVPA, along with Duke Energy Indiana and IMPA, are parties to a Transmission and Local Facilities Ownership, Operation and Maintenance Agreement for the joint ownership, operation and maintenance of the transmission facilities of Duke Energy Indiana, WVPA and IMPA in Duke Energy Indiana's Balancing Authority Area in Indiana (the "Joint Transmission System"). Mr. Wagoner stated that under the TL&F Agreement, WVPA has substantial rights to use the Joint Transmission System and substantial obligations for investment in the Joint Transmission System.

that the Company (through the collaborative stakeholder process) file a proposal with the Commission within six months of the Commission's order, in which the Company sets forth a proposal for access to energy usage data by customers and third parties.

Mr. Munson testified that Petitioner's proposal to work through a stakeholder collaborative to develop dynamic pricing and prepaid electricity programs is reasonable, but suggested the Company commit to submitting these programs to the Commission for approval within six months of the Commission's order approving the T&D Plan to provide assurance to customers that they will receive all of the benefits for the Company's investments. In addition, Mr. Munson recommended that the Commission require Petitioner to implement time-variant pricing plans within six months from the Commission's order approving the T&D Plan. He stated that without requiring time-variant pricing, the customers would be forced to pay for the improvement plan but would not receive the plan's full benefits.

Mr. Munson recommended the use of 20 reportable performance metrics associated with the Advanced Meter Infrastructure, as well as the operational tracking measure that Duke Energy Indiana should use for each. EDF Ex. DM-5. He stated that these proposed measures and metrics are similar to those agreed to be reported by ComEd and Ameren Illinois in Illinois in their smart grid deployment cases. He testified that if Duke Energy Indiana proactively reports on these items, it would avoid repetitive discovery during the annual tracker updates, resulting in more efficient proceedings. He stated that it is his understanding that Duke Energy Ohio and Duke Energy Carolinas did similar reporting to the Department of Energy relating to the Smart Grid Investment Grant, so it should not be overly burdensome since it should already have the information systems and management process in place to track and report on this information in Ohio and the Carolinas. Mr. Munson also testified that reporting is important because the data on carbon emission reductions arising from the T&D Plan could possibly be used for compliance with the EPA's Clean Power Plan.

6. Duke Energy Indiana's Rebuttal Testimony. In rebuttal, Ms. Birmingham-Byrd testified that in developing the T&D Plan, the Company did not stop with replacing aging infrastructure, but instead looked to the future of what its customers would want out of their electricity provider. The T&D Plan was put together focused on providing a modern foundation for the grid so that future products and services would be possible and customers could interact with the Company in the ways they are increasingly becoming accustomed to, such as text and mobile websites. She stated that Petitioner also sized its plan at about half of the investment that would have otherwise been permitted under the statute, resulting in an approximate 1% rate increase per year. She testified that the T&D Plan will modernize the grid and create value and trust through reliable service 24/ 7/ 365, through regulatory oversight of the improvements under the TDSIC statute.

In rebuttal, Mr. Schneider testified that Duke Energy Indiana does not believe its business case should assume some benefits of AMI, such as energy efficiency savings based upon customer behavior, given they are more difficult to quantify due to the dependence on customer behavior. He stated that the Company built its business case based upon readily identifiable and uncontroversial benefits, but it does not dispute the existence of other potential benefits of AMI, such as energy savings due to more enhanced energy usage data. Instead, those benefits would be provided directly to those customers based on the customers' actions, which underscores the Company's position that customers can benefit from the AMI deployment prior to the Company's rate case filing.

Mr. Schneider testified in rebuttal that Petitioner's proposed collaborative approach to developing customer pricing options enabled by AMI is a reasonable means to gain agreement on the detailed parameters of time of use rates and peak rebate pricing pilot programs. He stated that the Company proposes to meet with interested stakeholders within sixty (60) days of the Commission's Order approving AMI, where the Company will propose a pilot time-of-use option and a pilot peak time rebate or critical peak pricing option for residential and small commercial customers. Petitioner is willing to work with interested stakeholders on the design of the initial pilot programs with the goal of filing for pilot program approval within six months of the first collaborative meeting. Mr. Schneider testified that such a schedule would allow potential customer participation in pilot pricing offerings while the AMI roll-out occurs over the planned 4.5 year period. Mr. Schneider also testified that Duke Energy Indiana is willing to discuss a smart thermostat program either in the proposed collaborative for AMI-enabled offerings or in the Company's energy efficiency collaborative. He stated that Duke Energy Indiana is willing to commit to an investigation in 2015 of a smart thermostat energy efficiency and demand response program.

Mr. Schneider testified that Mr. Munson's recommendation for Petitioner to utilize "Green Button" to share data with customers and third parties is not prudent at this time. He stated that the more prudent course of action is scaling up its existing customer web portal functionality to make interval data available to customers. This will allow Duke Energy Indiana to use existing company resources, though scaled up to include Indiana, for sharing data with customers. He stated that the customer web portal will enable customers to download their energy usage data, at which point they can decide whether and how to share their own data with third parties.

In response to Mr. Munson's recommendation of various reporting requirements for its AMI deployment, Mr. Schneider stated that reporting can be costly and burdensome, so it should be limited to the most relevant and useful information that is not burdensome to collect and track. Based on experiences in other jurisdictions in terms of relevant information and ability to collect, Mr. Schneider provided examples of various AMI deployment build metrics and AMI benefit impact metrics to be tracked and reported annually.

In rebuttal testimony, Mr. Davey disagreed with Messrs. Phillips and Higgins regarding Petitioner's proposed cost allocation to HLF customers. He stated that the Company's cost allocation to HLF customers is reasonable, just, and equitable. Duke Energy Indiana made every effort to design allocations that complied with the statute and fairly allocated the costs of the T&D Plan to customer classes. He explained that the Company used the meter revenue requirement from the last rate case to allocate the meter costs included in the T&D Plan; such specification fairly allocates the costs of AMI to customers and still complies with the TDSIC statute requirement to use allocation factors from the prior base rate case.

There is no disagreement that the Company's proposal would saddle transmission voltage customers that *do not use the distribution system* with distribution investment costs. While Company witness Davey claimed that the Company's cost allocation to HLF customers is reasonable, just, and equitable, Mr. Davey did not rebut Mr. Higgins's recommendations that the share of Rider 65 revenue requirement allocated to HLF for recovering distribution system costs should be recovered almost exclusively from those HLF customers that are served at distribution system voltage or that this principle should extend to the LLF rate schedule as well.

Mr. Davey testified that he disagrees with Mr. Phillips' suggestion that the T&D Rider is part of the total bill, and thus the total bill (base revenues and all other riders) must be reviewed as part of the T&D Plan to determine if rates would be reasonable and just. Mr. Davey stated that this standard would require a full base rate case level of review in every rider that every utility files with the Commission, which is impractical and contrary to the statutory process outlined in Ind. Code § 8-1-39. He stated that every rate adjustment mechanism is reviewed by the OUCC, interested intervenors, and the Commission before the charges or credits become a part of the customers' bills. Mr. Davey testified that this process of reviewing and approving charges under rate adjustment mechanisms is a reasonable and just process, and results in reasonable and just rates. He testified that the FAC rider specifically includes an earnings test to ensure the overall net operating income does not exceed the allowed net operating income, which acts as protection against Mr. Phillips' assertion that rates are not just and reasonable due to changes that occur to rates in between rate cases. In addition, Mr. Davey testified that under the TDSIC statute a utility may not file a plan less than nine months since its last base rate case, and requires that a base rate case be filed before the expiration of the seven-year plan.

In rebuttal, Mr. Davey disagreed with Mr. Gorman's proposal for an ROE of 9.3% stating that the Company's currently allowed ROE of 10.5% was approved in the Company's most recent general rate proceeding, and the TDSIC statute makes clear that the ROE from the prior rate case is appropriate to use in T&D Rider proceedings. He stated that historical experience and sound regulatory policy also support using the same ROE for rate adjustment mechanisms as is used for the Company's base rates. In addition, should the Commission choose to review other Indiana ROEs as a check-point, the Duke Energy Indiana authorized ROE of 10.5% remains reasonable (as shown in the recent I&M order in Cause No. 44075).

In rebuttal testimony, Mr. Robert Hevert, Managing Partner of Sussex Economic Advisors, LLC, testified that Duke Energy Indiana's currently authorized return on equity falls in a reasonable range of analytical results, and neither capital market conditions nor the presence of the TDSIC Rider justifies a reduction to the ROE. He stated that beyond methodological differences, Mr. Gorman's 9.30% ROE recommendation is based on analytical results that are not supported by Mr. Gorman's data, are highly subjective, and are inconsistent with very relevant and observable data. Based on those analyses, Mr. Hevert concluded that the 9.30% recommendation is below any reasonable estimate of Duke Energy Indiana's Cost of Equity. Mr. Hevert performed several analyses in response to Mr. Gorman's testimony. In light of those results, and taking into consideration other relevant and observable market data, Mr. Hevert testified that Duke Energy Indiana's currently authorized ROE of 10.50% is within the range of returns required by equity investors under current and expected market conditions, and given the degree of financial leverage associated with the Company's currently authorized equity ratio. Mr. Hevert testified that Petitioner's ROE of 10.50% remains reasonable and appropriate.

7. Statutory Requirements. Ind. Code §8-1-2-4 provides that "[e]very public utility is required to furnish reasonably adequate service and facilities. The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited and declared unlawful."

Ind. Code § 8-1-39-10(a) permits a public utility to petition the Commission for approval of the public utility's seven year plan for eligible transmission, distribution, and storage improvements.

Ind. Code § 8-1-39-10(b) states that after notice and a hearing, and not more than 210 days after the petition is filed, the Commission shall issue an order that includes the following:

(1) A finding of the best estimate of the cost of the eligible improvements included in the plan;
(2) A determination whether the 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 the incremental benefits attributable to the plan.

Further, "[i]f the Commission determines that the public utility's seven year plan is reasonable, the Commission shall approve the plan and designate the eligible transmission, distribution, and storage improvements included in the plan as eligible for the TDSIC treatment." *Id.*

Ind. Code § 8-1-39-2 states that:

> As used in this chapter, "eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that: (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas . . . .

8. Commission Discussion and Findings.

A. Duke's Charge for Service. The Indiana Supreme Court has described the purpose of this Commission as follows:

> The purpose of the statute creating the Public Service Commission and defining its powers and duties, is supervision and regulation of public utilities within the state. It is designed to supply the missing element of competition which protects the public from excessive charges in competitive businesses. It is the duty of the

> Commission to see that the rates charged are fair and reasonable, both to consumers and the utility. Public Service Commission of Ind. v. Indiana Bell Telephone Co., 130 N.E.2d 467, 481 (Ind. 1955).

This statement is consistent with our reading of Ind. Code §8-1-2-4 which requires that any charge for service must be just and reasonable. Before looking at the TDSIC statute and whether Duke has complied therewith, we will first examine the requirement of Ind. Code §8-1-2-4.

Duke has proposed to implement a new tracker pursuant to Ind. Code §8-1-39. Duke proposes to undertake a seven-year plan of transmission and distribution improvements totaling over $1.8 billion and collect the costs through the new tracker.

The Industrial Group, through witness Phillips, questions whether we can approve Duke's proposal and remain consistent with our purpose as outlined in the above quote and Ind. Code §8-1-2-4. Mr. Phillips presents several facts which he believes makes it impossible for the Commission to find that Duke's rates would be just and reasonable after approval of the TDSIC proposal.

For example, Mr. Phillips observes that Duke's last rate case was filed on December 30, 2002, more than twelve years ago. Mr. Phillips showed that Duke's original cost rate base at that time was $3.6 billion. Duke has added $3.361 billion in additional rate base since the last rate case. Duke would add another $1.8 billion under its TDSIC proposal.

Mr. Phillips noted that Duke testified in the last rate case that its rates were significantly below the national average and below Indiana average rates. Mr. Phillips showed that Duke's rates were above the national and state averages by 2013. Duke's rates had gone up 88.9% while the national and state averages increased only 46.4% and 54.5%.

Mr. Phillips also showed that the rates for industrial customers had increased even more, growing by 100% and are now above the national average.

Another area that has experienced significant change is in consumption by rate class. Mr. Phillips demonstrated that while Duke's 2013 MWh sales were 10% higher than in the last rate case, rate HLF sales were down 12%. He stated that the allocation today of costs on factors determined in the last rate case, when changes of this magnitude have taken place over the last twelve years, results in over-allocations of cost to rate HLF. Mr. Phillips noted that Duke had acknowledged that rate HLF was being allocated more costs than is reasonable and just, with Duke proposing a change to its IGCC tracker to adjust for the reduction in customers and sales in rate HLF.

Duke did not address the question of whether its rates would be just and reasonable in its direct evidence. In its rebuttal, Duke does present arguments against those posed by Mr. Phillips. For example, Duke proposes that the cost allocation in the TDSIC proposal is reasonable because Duke made every effort to design allocations that comply with the TDSIC statute. Of course, Duke's allocation is based on the last rate case from 2002 and is subject to all of the concerns raised by Mr. Phillips.

Duke also responds to Mr. Phillips' statement that it is impossible for the Commission to find the charge Duke would impose on ratepayers for service would be just and reasonable if the Commission approved Duke's TDSIC proposal. Duke suggests that Mr. Phillips would require a full base rate case level review in every rider a utility files. We do not read Mr. Phillips testimony in this manner. Rather, Mr. Phillips raises the fact of the time that has elapsed since Duke's last rate case and the many significant changes that have taken place over that time including: the large changes in rate base, Duke's above average growth in rates, and the significant swings between rate classes. It is this fairly unique combination of the passage of time and the intervening material changes that Mr. Phillips believes prevent us from finding that Duke's charge for service would be just and reasonable after approval of Duke's TDSIC proposal.

Duke also argues that parties have had a chance to participate in all Duke tracker proceedings since the last rate case, and the Commission has approved each increase. This is true, but again Duke seems to misread Mr. Phillips' testimony. Mr. Phillips points out the significant factors that have changed over the twelve years since Duke's base rates that call into question the reasonableness of continued use of the allocation factors established in its last rate case. Accordingly, going forward it is not possible <u>at this point</u> to add another $1.8 billion dollar tracker to the charge for service for the next seven years with any comfort that the charge would be just and reasonable.

Duke also asserts other arguments in support of a finding that rates would be just and reasonable after the imposition of the TDSIC tracker. First, Duke notes the earnings test in the FAC. Of course, the authorized income in that test is based in part on the return on equity and other inputs approved in the last rate case, many of which could be different in a new base rate proceeding. Duke also cited to June 2014 average costs to support its view, in response to the 2013 average costs presented by Mr. Phillips. We do not find Duke's addition to the evidence supportive of a finding that Duke's rates would be just and reasonable. Interestingly, Duke's evidence demonstrates that its 2014 rates increased more than the State average and the national average rates did from those in 2013.

We have carefully considered the evidence presented and find that we are not able to determine whether Duke's charge for service would be reasonable and just as required by Ind. Code §8-1-2-4 if we were to approve Duke's TDSIC proposal.

As evidenced by the facts presented by Mr. Phillips, Duke's rate base and rates have almost doubled since Duke's last base rate case. Similarly revenues have increased by over $1 billion. Another fact is that Duke's rates have gone from below the national and state average to above both. In addition, the consumption by classes which is relevant to appropriate allocations of costs has changed significantly. Duke attempted to address this in the IGCC tracker filings but did not do so here. Further, within the HLF class differences in voltage produce different cost allocations in a cost of service study, a fact ignored by Duke in this filing.

These facts are magnified by the fact that there has been no comprehensive look at Duke's rates for over twelve years. The passage of time would naturally be expected to impact the accuracy of rates, but we have actual factual evidence here that demonstrates beyond question that significant rate related changes have taken place in the intervening years.

We are not persuaded that Duke's rebuttal evidence alters any of the points made by Mr. Phillips. Duke has presented no convincing evidence that its charge for service would be just and reasonable if we approved its TDSIC request. Duke's statement that it could have asked for larger annual increases under the statute than it did is not evidence that Duke's charge would be just and reasonable if we added the amount Duke did seek.

Further, we disagree with Duke's suggestion that our finding would necessitate a rate case type analysis in every tracker filing. Instead, we believe the question is whether, due to the passage of time and the occurrence of events over that time, further reliance on the allocations and other decisions made in a long passed base rate case can be determined to produce a charge for service that is just and reasonable after the addition of the requested TDSIC relief. We find that, in the circumstances presented in this proceeding, we cannot.

Duke could, as suggested by Mr. Phillips, seek a TDSIC program as part of a base rate case filing or after such a filing. Doing so would eliminate the uncertainty over whether Duke's charge for service would be just and reasonable.

Having reached this conclusion, we do not address whether Duke's T&D Plan's projects were eligible under Ind. Code § 8-1-39 and whether the public convenience and necessity require the projects, or whether Duke's estimate complied with the statute.

B. **Confidentiality Findings.** Duke Energy Indiana filed motions for protection of confidential and proprietary information on August 29, 2014 and December 16, 2014. In the motions and supporting affidavits, Duke demonstrated a need for confidential treatment for: (i) information related to Duke Energy Indiana's prospective transmission and distribution projects specific to the identity of transmission and distribution system assets; (ii) detailed cost information for the T&D projects; and (iii) information independently compiled and developed by third-parties used in measuring the financial risk of companies. On September 10, 2014, and January 8, 2015, respectively, the Presiding Officers made preliminary determinations that such information should be subject to confidential procedures. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. Duke's requested relief is denied in its entirety.

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

<u>STEPHAN, MAYS-MEDLEY, HUSTON, WEBER AND ZIEGNER CONCUR:</u>
APPROVED:

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

____

Brenda A. Howe
Secretary to the Commission

Alternate Options

<u>In the event the Commission finds that it can determine that Duke's charge for service would be just and reasonable after the addition of the requested TDSIC costs, the Industrial Group offers the following points for the Commission's consideration.</u>

1. Replace Duke's "Determination of Pretax Return" Section with the following:

<u>Determination of Pretax Return</u>. The TDSIC statute does not specify the rate of return for a TDSIC tracker, rather the statute provides that the Commission shall determine an "appropriate pretax return" and "may consider" several factors. I.C. 8-1-39-13(a). Duke proposed that it use the 10.5% return on common equity from its last rate case in Cause No. 42359 dated May 18, 2004 and that the capital structure be updated with each TDSIC filing along with debt costs. The Industrial Group proposed a rate of common equity of 9.3%, which was based on more recent market conditions.

During Duke's last rate case (conducted by the predecessor to Duke Energy Indiana, PSI Energy, Inc.), the Commission noted that the use of trackers reduces risk and that the Commission must consider the reduction in risk in determining an appropriate cost of equity. <u>PSI Energy, Inc.,</u> Cause No. 42359 (May 18, 2004) p. 53. Since its last rate case, which was based on a 2002 test year, Duke has added several other significant tracking mechanisms recovering approximately one-third of its total invested capital. Any amounts recovered through the TDISC tracker will be in addition to these amounts. Unlike other statutes which have authorized tracking treatment, the TDSIC statute authorizes the Commission to consider a reduction in the appropriate cost of equity.

The Commission was presented with two different recommendations for return on equity. The Industrial Group recommended 9.3%, which was the mid-point of the range of a various analyses conducted by Mr. Gorman for measuring Duke's cost of common equity based on current market conditions. Duke contended that its return on equity should remain at 10.5%, which was determined appropriate in its 2002 rate case. Many of the Company's analyses, however, actually supported reduction from a 10.5% return on equity. The average of Mr. Hevert's DCF analyses was 9.9%, with the highest DCF model only supporting a 10.29% return on equity. (Petitioner's Exhibits L-8 and L-9). Mr. Hevert's average risk premium was 10.39% (Petitioner's Exhibit L-13 average of 10.10, 10.20 and 10.86%). The Commission would have to rely solely on Duke's CAPM analysis and exclude all other evidence in order to find a 10.5% return on equity reasonable for the TDSIC tracker.

Duke's witness Hevert also claimed that the existence of tracking mechanisms should have no effect on the Company's cost of equity. The Commission has specifically found otherwise in a number of prior Orders. <u>PSI Energy, Inc.,</u> Cause No. 42359 (May 18, 2004) p. 53; <u>NIPSCO</u>, Cause No. 43526 (Aug. 25, 2010) p. 32; <u>In Re SIGECO</u>, Cause No. 43839, (April 27, 2011), p. 31. The Commission rejects Mr. Hevert's recommendations and finds that the evidence shows that Duke's cost of common equity for the TDSIC should be reduced from the 10.5% used in Duke's 2002 rate case.

Based on the foregoing discussion, our review of the substantial evidence presented in this cause and the language of the TDSIC statute, we conclude that Duke should use a 9.3% return on equity for purposes of determining its pretax return for TDSIC investments.

2. Replace Duke's Sections 9A – 9E with the following:

A. Failure to Satisfy the Requirements of the TDSIC Statute

The threshold prerequisite for relief under the TDSIC Statute is the presentation and approval of a 7-year plan identifying eligible transmission, distribution and storage system improvements that the utility will undertake to complete in the next seven years. See Ind. Code §8-1-39-10(a). In order to be approved by the Commission, a 7-year plan must satisfy a set of criteria specified in the statute, and in particular must be supported by a best estimate of the cost, a showing of public convenience and necessity, a determination that the estimated costs are justified by incremental benefits attributable to the plan, and a finding of reasonableness. Id. §10(b). If the 7-year plan is approved, the Commission is authorized to "designate" the improvements as eligible for TDSIC treatment. Id. See also Ind. Code §8-1-39-2(3)(A), (defining "eligible transmission, distribution, and storage system improvements" as those "designated" in an approved 7-year plan).

Duke's submitted 7-year plan fails the meet the TDSIC Statute's requirements in several regards. Duke failed to provide specific detail for projects in Years 2 through 7. Instead, it identified estimated annual spends. For year 1, Duke claimed it was providing more detailed information, but failed to provide sufficient cost-estimates to meet the statutory criteria of the "best estimate".

The basic quid pro quo underlying the TDSIC Statute permits a utility to recover costs for certain infrastructure improvements through a rate tracker, without filing a general rate case, only upon a grant of regulatory approval for a 7-year plan satisfying enumerated statutory prerequisites. The rate treatment for specified improvements may be pre-approved, before the utility makes the investments, but only where properly designated in a 7-year plan with sufficient detail to apply the statutory criteria. Duke's 7-year plan does not comply with the statutory requirements. There is no basis for determining the "best" estimate of costs, or deciding whether those costs were "justified" by incremental benefits. Absent a designation of identified improvements beyond annual "spends" based on best estimates for ratemaking, the Commission has no tangible foundation for determining public convenience and necessity or the reasonableness of the 7-year plan. Duke's 7 Year Plan must therefore be rejected for failing to meet the statutory requirements of the TDSIC Statute.