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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) APPROVAL OF PETITIONER'S TDSIC PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10(a) INCLUDING TARGETED ECONOMIC DEVELOPMENT PROJECTS PURSUANT TO IND. CODE § 8-1-39-10(c), (2) AUTHORITY TO DEFER COSTS FOR FUTURE RECOVERY, (3) APPROVAL FOR INCLUSION OF NIPSCO'S TDSIC PLAN PROJECTS IN ITS RATE BASE IN ITS NEXT GENERAL RATE PROCEEDING PURSUANT TO IND. CODE § 8-1-2-23, AND (4) AUTHORITY TO RECOVER OPERATION AND MAINTENANCE EXPENSES AS TDSIC COSTS PURSUANT TO IND. CODE § 8-1-39-7 UNDER ITS APPROVED RIDER 888 – ADJUSTMENT OF CHARGES FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGES.	)	CAUSE NO. 45557 APPROVED: DEC 28 2021

ORDER OF THE COMMISSION

Presiding Officers:
Stefanie N. Krevda, Commissioner
David E. Veleta, Senior Administrative Law Judge

On June 1, 2021, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed its Verified Petition, together with its testimony and exhibits constituting its case-in-chief, seeking Indiana Utility Regulatory Commission ("Commission") approval of its plan for eligible transmission, distribution and storage system improvements, pursuant to Ind. Code § 8-1-39-10(a), including specific targeted economic development ("TED") projects pursuant to Ind. Code § 8-1-39-10(c) for the period June 1, 2021 through December 31, 2026 ("2021-2026 Electric Plan," "TDSIC Plan," or "Plan"). On June 1, 2021, NIPSCO also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which the Commission granted on a preliminary basis in its June 11, 2021 Docket Entry.

The Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Municipal Utility Group ("IMUG"), NIPSCO Industrial Group ("Industrial Group"), Indiana Distributed Generation Alliance ("IndianaDG"), and Wabash Valley Power Association ("WVPA") each filed petitions to intervene, all of which were subsequently granted.

On July 15, 2021, the Industrial Group filed a Motion to Strike Confidential Attachment 1-B and related testimony ("Motion to Strike"). On July 23, 2021, NIPSCO filed a Reply to Industrial Group's Motion to Strike. And on July 30, 2021, the Industrial Group filed a Reply in Support of Motion to Strike.

On August 26, 2021, the Commission issued a Docket Entry denying the Motion to Strike in which it explained that the Economic Impact Report filed by NIPSCO as Confidential Attachment 1-B was relevant to its considerations under Ind. Code ch. 8-1-39, (the "TDSIC Statute") and noted that the Economic Impact Report had not been offered into evidence, so it would be premature to rule on its admissibility.

On July 27, 2021, NIPSCO filed supplemental testimony from Ms. Becker, in which she clarified NIPSCO's proposed tracker and plan update cadence. On August 30, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC"), and Industrial Group filed their respective testimony and attachments. On September 15, 2021, NIPSCO filed rebuttal testimony.

On September 30, 2021, NIPSCO filed revised testimony from Ms. Becker, which removed certain information from her direct testimony that was addressed in Mr. Thibodeau's rebuttal testimony, and from Mr. Holtz, which updated his job title and responsibilities.

On October 5, 2021, the Commission conducted an evidentiary hearing at 9:30 a.m., in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO, the OUCC, and the Industrial Group were admitted into the record without objection. NIPSCO also offered Petitioner's Exhibit No. 7 (NIPSCO Industrial Group's Responses to Northern Indiana Public Service Company LLC's First Set of Discovery Requests) and No. 8 (Indiana Office of Utility Consumer Counselor's Objections and Responses to Northern Indiana Public Service Company LLC's First Set of Discovery Requests), which were also admitted into the record without objection.

Having considered the evidence and being duly advised, the Commission now finds:

1. <u>Notice and Jurisdiction</u>. Notice of the hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility as that term is defined in Ind. Code §§ 8-1-39-48-1-2-1 and is an "energy utility" providing "retail energy service" within the meaning of Ind. Code §§ 8-1-2.5-2 and 3. Under Ind. Code §§ 8-1-39-10 and -11, the Commission has jurisdiction over a public utility's plan for eligible transmission, distribution, and storage improvements, including TED projects. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics</u>. NIPSCO is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO is engaged in rendering electric and gas public 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 generation, transmission, distribution and furnishing of such service to the public.

3. **<u>Requested Relief</u>.** In accordance with Ind. Code § 8-1-39-10(a), Petitioner requested Commission approval of its TDSIC Plan, as follows:

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

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

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

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

(e) a determination that the TDSIC Plan is reasonable and should be approved, and designating the eligible transmission, distribution and storage system improvements included in the TDSIC Plan as eligible for Transmission, Distribution and Storage System Improvement Charge ("TDSIC") treatment;

(f) authority to defer costs associated with the TDSIC Plan that are incurred prior to and subsequent to the issuance of an Order in this proceeding until such amounts are recovered through rates;

(g) approval of including Petitioner's TDSIC Plan projects in its rate base in any proceeding involving Petitioner's rates;

(h) approval of Petitioner's proposed process for updating the TDSIC Plan in future TDSIC adjustment proceedings;

(i) authority to recover operations and maintenance expenses ("O&M expenses") as TDSIC costs pursuant to Ind. Code § 8-1-39-7 under its approved Rider 888; and

(j) granting to Petitioner such additional and further relief as may be deemed necessary or appropriate.

4. **<u>NIPSCO's Case-in-Chief</u>.**

A. **<u>Direct Testimony of Alison M. Becker</u>.** Alison M. Becker, NIPSCO Manger of Regulatory Affairs, first outlined the relief NIPSCO is requesting in this proceeding and also provided an overview of the statutory authority that supports NIPSCO's requested relief. She testified that NIPSCO filed a notice of termination to the Commission on April 1, 2021 that terminated Electric Plan 1 effective May 31, 2021 and explained the eligible transmission, distribution, and storage improvements in Electric Plan 1 receiving TDSIC treatment under Section 9 of the TDSIC Statute as of May 31, 2021 will continue to receive TDSIC treatment under Section 9 of the TDSIC Statute after termination of the plan until a final order in NIPSCO's next general rate case is issued. She further explained that NIPSCO filed seeking approval of its electric basic rates and charges on October 31, 2018 in Cause No. 45159, as required by Ind. Code § 8-1-39-9(e).

Ms. Becker also provided an overview of the 2021-2026 Electric Plan. She testified that, consistent with the provisions of the TDSIC Statute, NIPSCO has developed an electric plan detailing the eligible transmission, distribution, and storage system improvements NIPSCO will undertake for purposes of safety, reliability, system modernization or economic development, which provides for appropriate economic development projects in the future, although none are proposed at this time. She explained that the 2021-2026 Electric Plan identifies the total annual projected costs and includes an Asset Register for Risk Based Projects (Confidential Appendix A) used to identify and prioritize the major assets measured and selected by NIPSCO's Risk Model (Substation Transformers, Substation Breakers, and Circuits), an Asset Register for Non-Risk Based Projects (Confidential Appendix B) used to identify and prioritize the Deliverability and Condition Based Projects, 2021 Project Estimates (Confidential Appendix C), and 2022 Project Estimates (Confidential Appendix D). She further explained NIPSCO is requesting approval for the total annual projected costs, including a portion for TED projects (when applicable), for Years 1 through 6. She noted the four main segments of the Plan and the associated cost, as outlined in Section 3 above. She also explained that NIPSCO does not intend to continue to identify the number of miles, breakers, or units for certain projects as is currently provided in the Project Detail pages in Electric Plan 1.

With respect to serving the public convenience and necessity, Ms. Becker testified that there is a reasonable and apparent need for the Plan and the eligible improvements included in the 2021-2026 Electric Plan will serve the public convenience and necessity in various ways. She testified NIPSCO's evidence demonstrates the estimated costs of the eligible improvements included in the Plan are justified by incremental benefits attributable to the Plan and that the Plan follows the requirements of the TDSIC Statute and achieves the legislative intent of making new and replacement transmission and distribution investments for the purpose of safety, reliability, system modernization, and economic development, which is consistent with public policy and serves the public interest. She explained how the Aging Infrastructure segment included in the 2021-2026 Electric Plan is essential to the continued safety of NIPSCO's employees and customers and reliability of NIPSCO's electric transmission and distribution systems. Further, to continue serving customers safely and reliably, while also complying with applicable laws, the public convenience and necessity require that the assets identified in the 2021-2026 Electric Plan be replaced, as the public's reliance on electricity is linked directly with quality of life, economic enhancement and overall public safety. For the System Deliverability segment, she testified this segment is essential in protecting the integrity, safety, and reliable operation of the system – not only for NIPSCO's customers, but also for the bulk electric system as a whole. Additionally, these investments provide for the public convenience and necessity at a much broader level than just NIPSCO's service territory by reaching not only its own customers but also all utilities and customers in the Eastern Interconnection. Finally, for the Grid Modernization segment, she testified this segment is essential to enhance customer service, improve reliability, and enable new technologies to improve NIPSCO's ability to meet customers' evolving operability expectations. For all these reasons, as well as those stated by Witnesses Vamos, Holtz, and Thibodeau, she stated that approval of the 2021-2026 Electric Plan is required and will be required for the public convenience and necessity.

Ms. Becker next testified how NIPSCO's estimated costs of the eligible improvements included in the 2021-2026 Electric Plan are "best estimates." She stated NIPSCO followed a rigorous project development, cost estimating and review process to provide its best estimate for each project included in the Plan and noted that Mr. Vamos provided extensive testimony on this topic.

Ms. Becker also briefly testified about how the estimated costs of the eligible improvements included in the 2021-2026 Electric Plan are justified by the reasonably expected incremental benefits attributable to the Plan. This is because the Plan effectively addresses safety, reliability, system modernization, and economic development. She also stated it is essential in considering the incremental benefit of the Plan to recognize that continued safe, reliable service from the eligible investments in the Plan be compared against the potential for service deterioration that would occur if these investments were not made.

Ms. Becker outlined the statutory requirements related to Economic Development Projects and noted NIPSCO did not identify any specific economic development projects in its Electric Plan 1, but is not proposing a budget for the general category of Economic Development Projects in its 2021-2026 Electric Plan. She also explained that in Electric Plan 1, NIPSCO agreed to the inclusion of an Economic Development project for LaPorte County Kingsbury Industrial Park, with a stated commitment to invest as much as $3.5 million for distribution system and substation upgrades associated with such a project, once the necessary project plans have been finalized ("Kingsbury Project"). Therefore, in its 2021-2026 Electric Plan, NIPSCO agreed to work with LaPorte County and support inclusion of the Kingsbury Project in a Plan Update filing. She stated at the time inclusion of the project is proposed, sufficient evidence will be provided for stakeholders and the Commission to evaluate the merits of the Kingsbury Project and any necessary upgrades, make a finding that a best estimate has been provided, and determine that the estimated costs of the project are justified by the incremental benefits attributable to the project.

Regarding the process for updating the Plan, Ms. Becker explained NIPSCO's proposal to update its 2021-2026 Electric Plan annually, but in no event more frequently than once every six months. Each Plan Update will be supported by information on the actual costs incurred and an explanation in testimony of any increase greater than $100,000 and greater than 20% during the current year for projects. She also noted that NIPSCO will provide an updated (1) Asset Register for Risk Based Projects (Confidential Appendix A to the Plan) and (2) Asset Register for Non-Risk Based Projects (Confidential Appendix B to the Plan), as new relevant information becomes available during the Plan update process. She also explained two changes NIPSCO is proposing to what is currently provided in its updates to Electric Plan 1. First, in updates to Electric Plan 1, NIPSCO includes four pages comparing the approved plan to the updated plan, including the related variances. Since similar comparisons are already included elsewhere in the updated plan, NIPSCO does not intend to provide those four pages in its updates to the 2021-2026 Electric Plan. Second, in updates to Electric Plan 1, projects with cost variances greater than $30,000 or 15%, whichever is greater, are supported by a project change request ("PCR") form. Instead, NIPSCO is committing to provide PCRs and testimonial explanations to support projects with cost variances greater than $100,000 and 20%.

In her supplemental testimony, Ms. Becker further testified about NIPSCO's proposed Plan update process. Specifically, she testified that NIPSCO determined an annual update will allow for a more complete update regarding projects that are in-service, project changes, and project estimates, as this annual filing will report on the entire prior calendar year. She confirmed the annual update will continue to include: (1) explanations and testimony for the prior year projects, the majority of which should be complete and in-service; (2) project change explanations and testimony for current-year projects; and (3) updates from parametric estimates to detailed engineering estimates for the future year, and, in addition, moves and other plan changes will be included, as they historically have been provided in Cause No. 44733-TDSIC-X. She noted that under Electric Plan 1, NIPSCO's second semi-annual Plan update typically included current-year updates and some future-year estimate updates, but there is value in incorporating these semi-annual Plan updates into one annual update primarily related to a reduced regulatory burden for stakeholders and a clearer picture regarding the status of the projects. She also explained that while the 2021-2026 Electric Plan will only be updated annually, NIPSCO will continue to file Plan Updates with updated costs in a tracker filing twice each year. One tracker filing will be part of the Plan update filing, and the other tracker filing will occur approximately six months later, which will allow NIPSCO to update the costs associated with projects that have been placed in-service and make appropriate adjustments to the TDSIC factor twice each year.

Ms. Becker confirmed NIPSCO will comply with the requirements of Ind. Code § 8-1-39-9(e) and will file for approval of NIPSCO's basic rates and charges before the Plan expires. She further confirmed that (1) all of the projects included in NIPSCO's 2021-2026 Electric Plan are undertaken for purposes of safety, reliability, grid modernization, or economic development; (2) none of the projects included in the 2021-2026 Electric Plan are included in NIPSCO's current base rates; (3) the 2021-2026 Electric Plan provided the best estimate of the cost of the eligible improvements; (4) the public convenience and necessity requires or will require the eligible improvements included in the 2021-2026 Electric Plan; (5) the Plan is reasonable; and (6) the estimated costs of the eligible transmission and distribution system improvements included in the 2021-2026 Electric Plan are justified by incremental benefits attributable to the Plan, as further discussed in NIPSCO's evidence.

Ms. Becker also testified about NIPSCO's stakeholder outreach efforts related to the 2021-2026 Electric Plan and provided Attachment 1-B, which is a copy of the presentation NIPSCO utilized during stakeholder meetings.

Ms. Becker concluded by outlining each witness that was offering direct testimony and discussing tariff changes that may be required if the Commission ultimately approved NIPSCO's proposed Advanced Metering Infrastructure ("AMI") Project. Specifically, she confirmed that, as it does for its Automated Meter Reading ("AMR") meters, NIPSCO will continue to allow customers to "opt out" of installation of an AMI meter if they so choose and that NIPSCO anticipates that revisions will be necessary to include an opt-out charge in Rule 15 – Miscellaneous and Non-Recurring Charges. However, since NIPSCO anticipates the initial implementation of 3,000 meters will not occur until 2023, in this filing NIPSCO is proposing to revise its Tariff after a final Order is issued in this Cause approving the AMI Project and will do so through a 30-day filing. She stated NIPSCO will work with all parties to this proceeding in developing the required

Tariff modifications.

B. Charles A. Vamos. Mr. Vamos, NIPSCO Director of Electric T&D Engineering, sponsored NIPSCO's 2021-2026 Electric Plan (Confidential Attachment 2-A) and explained various details about the Plan, including how the Plan was developed, the expected reduction in risk, how cost estimates were developed, the major components or categories of the Plan, and how the Plan will be executed. In addition to the Plan itself, he also sponsored several attachments NIPSCO provided in support of the Plan, with the assistance of Sargent & Lundy, L.L.C. ("S&L"). Specifically, S&L prepared four reports: (1) 2021–2026 TDSIC Investment Plan Business Case ("Long-Term Investment Plan") (Confidential Attachment 2-B); (2) 2021–2026 TDSIC Investment Plan Cost Analysis (Confidential Attachment 2-C); (3) Long-Term Communications Plan (Confidential Attachment 2-F); and (4) Economic Impacts of Projected NIPSCO T&D Expenditures, 2021–2026 ("Economic Impact Report") (sponsored by Witness Thibodeau as Confidential Attachment 6-R-A). He testified that the capital investment in the Plan is one of many components within NIPSCO's overall investment strategy, which also includes annual capital maintenance work, generation investments and transition, public improvement projects, as well as investments related to new business.

Mr. Vamos testified the three main objectives of the Plan are: (1) maintaining safe and reliable performance while proactively replacing aging, high risk equipment across the system; (2) maintaining adequate system capacity to reliably serve customer loads; and (3) modernizing NIPSCO's electric grid with technologies that support improved reliability, asset health and condition, and preparing for future customer expectations.

Mr. Vamos explained how the Plan was developed through the process of evaluating risk-based projects, programmatic minor asset projects, deliverability-based projects, and strategic grid modernization initiatives to support customer experience and system reliability. First, for risk-based projects, major assets that should be included in the 2021-2026 project portfolio were prioritized based on the consequence of an asset failing and likelihood of an asset failing. Through the proactive replacing of the highest risk assets, the overall risk of failure is reduced, as compared to simply replacing assets as they deteriorate and fail. This dynamic risk assessment considers age, condition, and prioritization of assets that are approaching or have met end of life. For programmatic minor asset projects, which are included in the category of Aging Infrastructure, he testified minor assets (such as annunciators, arresters, protective relays, insulators, line and substation switches, potential transformers, steel structures, substation batteries and chargers, substation capacitors, and wood poles) are vital to the safe and reliable operation of the electric system. While these minor assets are critical, he noted that they are not assigned a risk score within the Plan. These investments make up approximately 54% of the capital expenditures included in the 2021-2026 Electric Plan.

Mr. Vamos also explained the second process, which is focused on increasing the deliverability of power to meet customer load, which in turn maintains and improves reliability for customers, especially when load grows. These projects increase the system's ability to provide power to increasing customer demand, as well as providing versatility as load demands become more diverse and make up approximately 20% of the capital expenditures included in the 2021-2026 Electric Plan.

He then explained the third process, which is deploying strategic grid modernization initiatives to enhance customer service, improve reliability, and enable new technologies to improve NIPSCO's ability to meet customers' evolving operability expectations. The technologies proposed are AMI, intelligent sensing equipment (i.e., substation automation ("SA") and distribution automation ("DA") technologies), a distribution supervisory control and data acquisition ("DSCADA") system, as well as the inclusion of communication and telecommunication infrastructure. He testified this category of projects will together increase reliability and functionality, both of which are directly realized by NIPSCO's customers, and they make up approximately 26% of the expenditures included in the 2021-2026 Electric Plan.

Mr. Vamos testified about NIPSCO's Electric Plan 1, which was approved in Cause No. 44733 and was initially proposed to span from January 1, 2016 through December 31, 2022, but was terminated effective May 31, 2021. Through January 31, 2021, he noted NIPSCO had invested approximately $781 million through Electric Plan 1 and included certain statistics of the assets that were replaced. He explained NIPSCO's initial projection of an estimated 30% risk reduction if all projects under Electric Plan 1 were executed through 2022 and that NIPSCO has realized a 21% risk reduction when compared to a "break/fix" replacement strategy with its investments through May 31, 2021. He noted this was a significant accomplishment, which demonstrates the efficacy of NIPSCO's proactive replacement and capital investment strategy.

He further testified about NIPSCO's decision to terminate Electric Plan 1 and file the 2021-2026 Electric Plan. He explained that Electric Plan 1 was successful in reducing system risk by replacing aged assets and addressing changing system demands but some projects identified for execution in 2021 and 2022 required reprioritizing to NIPSCO's most recent system loading and condition information and the "snapshot" of NIPSCO's system from 2016 needed to be updated. He further explained that NIPSCO has realized an unexpected, sudden increase in electric demand in the eastern part of its service territory caused by the recent increase in new manufacturing facilities and that NIPSCO will also be pursuing grid modernization efforts that were not previously included in Electric Plan 1. Additionally, he noted the TDSIC Statute as it existed in 2016 (as interpreted by the Commission and courts) and the settlement agreement NIPSCO executed for the Electric Plan 1 did not allow for the addition of new projects, but an amendment to the TDSIC Statute has expanded the categories of allowable TDSIC projects. All of this in combination led NIPSCO to decide to terminate its Electric Plan 1 and develop and file the 2021-2026 Electric Plan, a plan that proposes projects based upon a more updated view of NIPSCO's electric system and projects that will enable NIPSCO to modernize its system to provide the service its customers expect and deserve.

Mr. Vamos testified the 2021-2026 Electric Plan was developed with the primary goal of the Plan of deploying a portfolio of investments in electric transmission and distribution facilities that preserves NIPSCO's ability to serve peak load, maintain system performance, ensure the safety of NIPSCO's systems, and enable evolving energy technologies, such as Distributed Energy Resources ("DERs") and electric vehicles ("EVs"). Within the four categories (safety, reliability, grid modernization, and economic development), the Plan is estimated to reduce the overall system risk, increase the deliverability of electric service, and enhance system automation to reduce customer outages and enable asset condition visibility. He explained how NIPSCO focused its review to all of its electric transmission and distribution assets and provided statistics on the number of NIPSCO's distribution and transmission assets. He noted NIPSCO's review included all substation transformers, circuit breakers, system protection devices, and other ancillary substation equipment in its transmission, sub-transmission, and distribution substations, including the structures and the corresponding overhead and underground conductors associated with the transmission, sub-transmission, and distribution circuits. Mr. Vamos further explained certain key facts about NIPSCO's system, including the continuing aging of assets that were installed 40-50 years ago and have reached the end of their useful lives.

Mr. Vamos also testified that the 2021-2026 Electric Plan was developed to address risks identified and prioritized as of early 2021, and as such, the Plan represents the current best path forward to ensure the continued delivery of safe and reliable electric service to NIPSCO's customers. The Plan also builds on the capital investments prioritized in Electric Plan 1 and addresses identified areas of needed modernization. In considering Plan design, he explained that NIPSCO conducted comprehensive reviews of many segments of its electric system and the Plan addresses high priority safety and operational and integrity needs. Projects were also reviewed to provide a high level of confidence that they could be executed as proposed and could be executed in a logical and efficient manner.

Mr. Vamos reiterated the approximately 21% risk reduction (from a 2016 baseline) NIPSCO realized from executing Electric Plan 1; whereas, had those projects not been completed, the NIPSCO system risk would have increased 19% from the 2016 baseline (assuming no other work was performed during that period). He emphasized one of the primary goals of the Plan is to reduce the overall system risk associated with aging asset populations and asset failures. While acknowledging the proposed investment levels in this Plan are substantial, and even with the 21% risk reduction realized under Electric Plan 1, he explained there are still many older, aging assets on NIPSCO's system that need to be replaced before they fail. When comparing the proactive replacement strategy under TDSIC to a "break/fix" strategy, based on the TDSIC Risk Model, he noted NIPSCO estimates an overall risk reduction of approximately 16%, demonstrating there is an opportunity for further investment under the 2021-2026 Electric Plan to continue to reduce risk, thereby increasing system reliability and better serve NIPSCO's customers. He explained the 16% represents a projection of the reduced risk score calculated for the specific major asset(s), (i.e., transformers, breakers, circuits), but does not necessarily represent a percentage reduction in the likelihood of an issue with the asset(s).

Mr. Vamos testified there were several reasons for the variance between the 21% realized risk reduction under Electric Plan 1 and the estimated 16% risk reduction under this Plan, but two factors drive the majority of the difference. The first reason is that the initial assets addressed in Electric Plan 1 were of higher impact, because there were the highest risk assets of the whole NIPSCO asset population, including the assets being replaced under this Plan. The second reason is driven by lessons learned by NIPSCO as it executed Electric Plan 1. Under this new approach, NIPSCO identified the opportunity to replace some assets that are just as old as targeted assets of the project in the same substation or the same circuit and determined the most cost effective and least interruptive method to address all of the related assets in the Plan is to perform all of that work at the same time. (For example, a typical substation includes circuit breakers for the lines entering and leaving the station, as well breakers for connecting the buses during maintenance. The line breakers are subject to harsher operating conditions than the bus breakers.) He explained that under Electric Plan 1, there were instances where just the line breakers were replaced, leaving the older bus breakers in service, but, under the Plan, all the breakers at the substation would be replaced. This more holistic approach to replacing aged assets on its system and replace them at the same time as the higher risk assets since resources are already deployed and outages are taken will be a more cost-effective and reliable method for customers in the long run, yet it also means that NIPSCO will be replacing some lower risk assets in conjunction with the higher risk assets identified through the TDSIC Risk Model.

Mr. Vamos also provided a description of the flexibility and potential Plan changes over time. He noted that while the 2021-2026 Electric Plan was developed to address risks identified and prioritized as of early 2021 and represents the current best path forward to ensure the continued delivery of safe and reliable electric service to NIPSCO's customers, it is certainly possible that projects in the Plan might change or be replaced, or that new projects might be proposed. This depends on a number of factors, including, but not limited to: (1) the continued evolution of the TDSIC Risk Model; (2) identification through routine and special inspection and assessment cycles of assets at risk for continued operability; (3) identification of risks through other NIPSCO process improvement and safety initiatives; (4) load growth and potential economic development projects; (5) the development of new technology to increase public safety or that offer more economical solution; and (6) the development of unpredicted asset failure, of which more expedient replacement or repair is required. NIPSCO would not make this decision on its own; rather, he explained any project in the Plan that is proposed to be replaced or any new project that is proposed to be added to the Plan would be included in a plan update filing pursuant to Section 9(b) of the TDSIC Statute. Then, if approved, NIPSCO would seek deferral of costs associated with the replaced or new project and recovery of the costs associated with a replaced or new project in future plan update filings.

Mr. Vamos testified that, consistent with the process outlined in Section 9 of the TDSIC Statute, NIPSCO proposes to update the 2021-2026 Electric Plan annually, but in no event more frequently than once every six months. In addition to the statutory requirement to file an updated plan, he explained it is prudent and necessary for NIPSCO to systematically and periodically review, revise, and update its Plan to respond to the dynamic nature of its transmission and distribution system, customer demand, and equipment failures. Therefore, as NIPSCO learns more in the upcoming years, the Plan will be updated as necessary. While the models utilized to develop the Plan are sound and it has been based upon the best available information, it is impossible to perfectly predict the future. As such, when these unanticipated events occur, the Plan will be re-prioritized. Thus, as information inputs change, the Plan will continue to be optimized to ensure the best plan possible is being deployed, and, when necessary, NIPSCO will work with all stakeholders when seeking to add new projects to the Plan.

With respect to the timing of Plan updates, Mr. Vamos stated NIPSCO's proposed update process is similar to the process used for Electric Plan 1 with the exception that NIPSCO is proposing to update its Plan annually. NIPSCO proposes to continue the current process of meeting with its stakeholders approximately four weeks prior to filing each Plan update. In its fall filing, the Plan will be updated with NIPSCO's best estimate by project for each calendar year. The risk registers (Confidential Appendices A and B) will be updated as new, relevant information becomes available during the Plan update process. Project Change Request ("PCR") forms and testimonial explanations will be provided to support project estimate changes greater than $100,000 and greater than 20% during the current year for projects. Actual costs will be included in the annual Plan update after a given calendar year is closed out. And the annual Plan update will define the detailed project scopes and update unit cost estimates for the next calendar year, if needed.

Mr. Vamos testified the estimated costs of the eligible improvements included in the 2021-2026 Electric Plan are justified by the incremental benefits. He testified extensively about the incremental benefits associated with the 2021-2026 Electric Plan. The Plan's investments positively impact electric reliability, safety, and grid modernization while resulting in positive economic impact for Indiana and for appropriate economic development projects in the future, although none are proposed at this time. Reliability drivers include the following: (1) reducing direct customer outages; (2) shortening customer outage durations; (3) maintaining continuity of service (self-healing system); (4) better managing peak system loading periods; (5) increasing flexibility for system sourcing; (6) increasing system visibility and validation; (7) enabling future technologies; and (8) more timely notification of outages (AMI).

Regarding safety, he testified this is of utmost importance to NIPSCO, its customers, and the broader public. Maintaining safety performance is therefore a requirement for NIPSCO's workforce and its customers, and one of the main objectives of the Plan. Safety will be enhanced when the likelihood of violent failures (i.e., explosions, fires, downed power lines) are mitigated through aging infrastructure replacement. Additionally, the increased visibility for fault detection and system modernization assists in preventing violent failures from occurring as well, and the extension of new facilities provides for a more robust system to meet deliverability or interconnection requirements.

Mr. Vamos also testified how the proactive replacement of aging infrastructure will help maintain the reliability of NIPSCO's electric transmission and distribution systems, which are growing older, and therefore riskier, with each passing year. The 2021-2026 Electric Plan targets the highest risk and consequence of failure assets, as identified in NIPSCO's Risk Model. He noted that in developing the Plan, NIPSCO carefully prioritized the list of planned investments to optimize the benefits of the investments while taking into account execution resources, engineering resources, and system constraints. As discussed above, for risk-based projects, the Plan represents an optimized risk reduction of approximately 16% versus a break/fix strategy.

Mr. Vamos further testified that proactive replacement of aging infrastructure also provides opportunities to replace old equipment with modern technology in a systematic and deliberate manner. He explained NIPSCO proactively evaluated the execution of projects throughout the Plan and combined projects or project categories for efficiency, both in terms of gained time and reduced overall capital costs. For example, the original driver for a transformer replacement project may be age and condition; however, the new transformer will include substation automation and communication components that are primarily driven by grid modernization. This consolidation process will allow NIPSCO to reduce mobilization, overhead, and labor costs, and potentially reduce the number of scheduled outages.

Grid modernization benefits were also discussed by Mr. Vamos. These benefits include optimizing NIPSCO's outage response, reducing unplanned asset failures, improving system flexibility, and laying a groundwork for future growth to implement modern technologies. He explained that by proactively enhancing the monitoring of asset and system health, NIPSCO will be able to avoid increasing levels of reactive or emergency work, which are often more expensive to perform due to premium labor rates and expediting fees, and often introduce additional, preventable safety risks. Because unplanned asset failures are also typically more disruptive to customer service and have the potential to damage customer equipment or jeopardize personnel safety, this will benefit NIPSCO and its customers. He also noted that the grid modernization projects include modern system protection devices that provide for faster clearing of system faults which will protect the health of NIPSCO's assets and minimize the breadth of future outages.

Finally, he testified the 2021-2026 Electric Plan fosters economic development, a key benefit of the Plan that will be spurred by these investments in the electric system. He referred to the Economic Impact Report prepared by S&L (and sponsored by Witness Thibodeau), which shows the positive economic impact of these investments to Northern Indiana and broader U.S. The Plan also provides for appropriate economic development projects in the future, although none are proposed at this time.

As for quantification of incremental benefits, Mr. Vamos explained how NIPSCO approached various kinds of projects, some of which have benefits that are difficult to quantify or monetize. For example, the expected 16% risk reduction is intended to reduce the likelihood of failure and the attendant risk to service reliability and continuity and the availability of system capacity. However, the benefit to NIPSCO's customers from Aging Infrastructure and System Deliverability investments cannot be easily calculated in an actuarial calculation. On the other hand, he explained that investments in Grid Modernization is one area where the estimated benefits can be monetized. The Distribution Automation Program Business Case (Confidential Attachment 2-E) monetizes the value of the proposed distributed automation program. NIPSCO and Leidos utilized the U.S. Department of Energy's Interruption Cost Estimation ("ICE") calculator to place a value on customer interruption costs and savings that would be realized by customers as a result of NIPSCO implementing specific Grid Modernization investments. The report summarizes that investments in DA grid modernization result in a cost savings of approximately $592 million over the period of twenty years, compared against the investment of approximately $52 million for DA grid modernization projects over a 10-year period, which he acknowledged is beyond the 2021-2026 Electric Plan window. He also noted that Witness Kiergan discusses monetized benefits in a cost benefit analysis for the AMI Project.

Mr. Vamos outlined the overall Plan cost estimate. Mr. Vamos explained that the total estimated capital cost of the 2021-2026 Electric Plan includes plan development costs and preliminary survey and investigation ("PS&I") costs. As has been NIPSCO's standard practice under Electric Plan 1, PS&I costs for specific projects will be included in the project's land acquisition, preconstruction, environmental, and construction work order (direct capital) and typically will be distributed when the work order is opened based upon the type of typical project planning and sequencing year of project execution. Additionally, he explained plan development costs will be amortized over the life of the Plan as capital overhead (or indirect capital).

He also testified extensively about the techniques used by NIPSCO and S&L to develop a cost estimate for a project. Each cost estimate is developed at a point in time and is based on the information known when the estimate is developed. As the project progresses, the information used as inputs into the cost estimation process becomes more accurate. He confirmed that as plan years proceed the level of estimate will continue to progress. Projects three years from execution will have gone through, or are going through, the scoping phase of the project and may progress to a Class 4 project. Projects will have updated estimates at an AACE Class 3 level 18 to 24 months from execution. And Programs will have been detailed engineered by the execution year 1 and can be considered a Class 4. The 2021-2026 Electric Plan (Confidential Attachment 2-A) provides a summary of project level estimates by year, which includes all investments represented in direct dollars. Confidential Attachment 2-A, Confidential Appendix C includes the detailed cost estimates for the 2021 projects. Confidential Attachment 2-A, Confidential Appendix D includes the detailed cost estimates for the 2022 projects. And Confidential Attachment 2-C includes design basis cost estimates broken down by direct and indirect costs (including labor and material) for Program Projects for 2021 and 2022, and for all projects included in 2023-2026.

Mr. Vamos continued by explaining how direct capital cost estimates for 2021 and 2022 were developed by NIPSCO's Project Scope and Estimate Development Team, utilizing detailed site reviews, internal engineering, operations, and planning expertise and outside engineering input. He confirmed all estimates were reviewed by NIPSCO's internal stakeholders, leading to project estimates for 2021 and 2022 that are considered Class 3/4 estimates. He noted that the direct capital cost estimates for 2023-2026 were developed by S&L and NIPSCO using a modular cost estimating approach using historical unit cost data, labor rates for external contractors, labor rates for internal NIPSCO labor, vendor budgetary quotations for major substation assets, NIPSCO's Geographic Information System ("GIS") for evaluating line rebuild assets, and construction contractor per unit budgetary validations for installation. The modular estimates were then applied to each project based on type of known scope. These project estimates are considered Class 5. However, given the repetitive nature and the large number of projects, along with NIPSCO's experience with this type of work, he confirmed there is a high level of confidence in these cost estimates. He also noted the estimate review process is continuous throughout the project development process. He then provided testimony about how S&L and NIPSCO worked together to develop estimated direct capital costs, indirect capital costs, and the estimated AFUDC rate, which will vary over time.

Mr. Vamos testified that 2021-2026 Electric Plan provides the best estimate of the cost of the transmission and distribution system investments included in the Plan. He noted the 2021-2026 Electric Plan includes projects that are similar to work NIPSCO performed in Electric Plan 1 and that NIPSCO utilized S&L to complete the modular cost estimates, followed by internal stakeholder reviews of those estimates. He confirmed that NIPSCO has gained and continues to gain experience with respect to the costs necessary for project completion, and cost estimates for this work reflected from NIPSCO's experience on the range of executed projects of the previous Electric Plan 1 projects of different types.

For all projects, Mr. Vamos explained that broad internal stakeholder input was collected to assure comprehensive integrated work scopes were documented and validated through a formal review process. NIPSCO followed a rigorous project development, cost estimating, and review process to provide its best estimate for each project included in the Plan. For smaller project estimates, typically under $1,000,000, he noted these are generally based on parametric or unit price estimates that reflect a mix of contractor and internal labor resources similar to the allocation of work maintained during Electric Plan 1. Even though they are comparatively smaller in cost, review of route and site conditions was completed for many of these projects. He also provided further detail on how estimates were created for Program Projects and Site-Specific Projects (substation or line projects).

For five large substation projects, Mr. Vamos explained the additional rigor NIPSCO undertook with S&L's assistance. Walkdowns were performed, site boundary survey's produced, a preliminary work scope identified, with conceptual layouts prepared for project execution, route reviews, and NIPSCO internal stakeholder reviews performed. The estimates prepared for these five large substations were based on a bottom up, non-modular estimating approach. Cost data from recent projects and updated budgetary quotations from construction contractors were used as the basis for the estimates in most cases, with experience modifiers considered for site specific conditions. A detailed bill of materials was developed through the preliminary engineering phase and updated prices were obtained from NIPSCO suppliers. A preliminary, high-level schedule was also developed to identify detailed engineering, land acquisition, and permitting lead time requirements.

Based on the estimates produced by S&L and NIPSCO, and the comparison to actual costs of similar projects in recent years, Mr. Vamos affirmed that NIPSCO is confident that these are the best estimates for the respective stages of planning for the projects included in the 2021-2026 Electric Plan. He summarized by stating NIPSCO worked with S&L to develop the best estimate of the cost for each investment. Therefore, the estimates included are NIPSCO's best estimates as of the time of filing, and NIPSCO will continue to refine these estimates as it enters into different phases of the project cycle and provide the refined estimates in future plan updates.

Regarding contingency, Mr. Vamos testified NIPSCO has included contingency as part of cost estimates, consistent with the Commission's findings relating to the "best estimate" of costs under the TDSIC Statute in prior proceedings, citing to Commission orders in Cause Nos. 45330 and 45264. Consistent with the Commission's findings, he explained NIPSCO included contingency consistent with the AACE Recommended Practice for cost estimate classification. He also noted that the contingency incorporated in the estimates for each of the 2021-2026 Electric Plan projects is consistent with industry practice for these types of projects and is consistent with the AACE Recommended Practice and NIPSCO's experience for risk that can impact a project cost gained through the execution of projects within Electric Plan 1. He stated the preliminary engineering for most projects in the 2021-2026 Electric Plan would support a Class 5 estimate based on the application of recent construction experience, added efforts to inspect and understand site conditions, identification of real estate and environmental requirements, and characterization of project risks, especially on the larger transmission projects. He further explained the process used by NIPSCO to determine the appropriate contingency for each project and project-specific risks considered by NIPSCO in developing contingency.

Aging Infrastructure Projects account for approximately 54% and $753,121,380 (direct capital) of NIPSCO's Plan. Mr. Vamos began by outlining the importance of replacing aging infrastructure in terms of improving system performance impacting safety, reliability, and operational performance, as well as system hardening and resiliency. He explained Aging

Infrastructure investments are projects aimed at reducing reliability risk by replacing or rehabilitating electric transmission and distribution assets that are of high consequence and are either approaching, have met, or have surpassed their expected life. These investments were identified in two ways. First, NIPSCO worked with the asset management team at S&L to update an overall risk model for its power transformers, circuit breakers, and circuits, using the same risk model used in Electric Plan 1. This was used to develop the proposed 2021-2026 Electric Plan, and an optimized portfolio of electric transmission and distribution assets was then selected to be addressed based on the result of this risk analysis. Second, NIPSCO independently evaluated groups of system assets to identify and prioritize the assets within each group with the greatest potential of failure based on their age and condition.

Based on the nature of how specific projects are selected, Mr. Vamos noted the Circuit Performance Improvement, Steel Structure Life Extension, and Pole Replacement projects are not included in an asset register. Circuit Performance Improvement investments are determined on an annual basis by analyzing reliability data and determining which circuits are most in need of improvement. For purposes of development of the Plan, expected projects are included in categories such as sectionalization, distribution automation, circuit rebuild, conductor replacement, or other specified performance improvement based on root cause. At the beginning of 2021, NIPSCO reviewed 2020 performance and determined the 2021 Circuit Performance Improvement projects and developed project scope and cost estimates. The Steel Structure Life Extension project is designed to extend the life of NIPSCO's steel structures or rehabilitate those that do not meet the accepted strength requirements and is necessary to address NIPSCO's aging steel structure population that is continuing to deteriorate. Over the life of the Plan, NIPSCO will inspect approximately 1,779 structures, and based on historical experience expects approximately 20% of those assets inspected to require some type of rehabilitation. The Pole Replacement project is designed to inspect, treat, and replace NIPSCO's wood pole population. Wood poles are the largest asset classification on NIPSCO's transmission and distribution system. With the average age wood poles being greater than 40 years, he explained it is necessary to actively assess the condition and make any necessary repairs or replacements to ensure integrity of the system, which is accomplished by development of a 10-year rolling inspection of each pole to determine condition and to replace or treat the pole for life extension if necessary. With each inspection, the pole will either be treated to reduce the rate of future decay, or, if it does not pass the test, the pole will be replaced. The pole inspection, treatment, and replacement project improves system reliability, safety, and system hardening during major event days by ensuring all poles meet the strength requirements set forth in the National Electric Safety Code ("NESC"). NIPSCO plans to inspect approximately 184,000 poles over the life of the Plan. Based on historical experience, it is anticipated that approximately 5-6% of the inspected poles will be replaced, with the exception of those already inspected in years with above-average rejection rates. Each of these three projects will be updated in each Plan Update filing. Aging infrastructure is a significant portion of the Plan, and the projects have been separated into three categories: (1) risk ranked projects, (2) projects ranked using other data sources, and (3) assets included in the TDSIC Risk Model, but selected and prioritized based on independent assessments. Mr. Vamos then provided further description of these categories.

Regarding NIPSCO's TDSIC Risk Model, Mr. Vamos testified it was used to rank and help select the risk ranked Aging Infrastructure projects included in the 2021-2026 Electric Plan.

NIPSCO used a systematic risk model to quantify the criticality of three types of major transmission and distribution assets to the overall electric system: (1) overhead and underground circuits, (2) transformers, and (3) circuit breakers. The model uses a standard definition of risk: Risk = Consequence of Failure ("COF") x Likelihood of Failure ("LOF"). Through a quantified risk-scoring model, each major asset that is part of the NIPSCO transmission and distribution system is scored based on the different COF and the asset's LOF with 1 being lowest and 5 highest. He further explained that, while the COF for an asset does not necessarily change a great deal with the passage of time (unless redundancy is added to the asset base or system configurations alter the impact of the asset), the effect of infrastructure aging is that the likelihood of failure increases with each year, which over time results in an unacceptable level of risk for the utility. Thus, NIPSCO's 2021-2026 Electric Plan will reduce that risk in an efficient and orderly manner. He also outlined the constraints that were modeled in the Risk Model.

After describing how the COF and LOF were calculated for each asset in the Risk Model, Mr. Vamos explained how NIPSCO determined which projects would be included in the Risk Ranked Aging Infrastructure investments of the 2021-2026 Electric Plan. He reiterated that NIPSCO's approach in the development of the Plan was to reduce reliability risk in the most efficient manner possible. NIPSCO used the TDSIC Risk Model results, as well as system constraints, to develop an optimized aging asset replacement plan, which is provided in the Asset Register for Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix A). The optimization methodology used in the development of the Plan sought to achieve the greatest risk reduction possible for the dollars invested. This included moving projects earlier or later in the planning schedule to create operational and construction efficiencies. Mr. Vamos also confirmed NIPSCO will review the risk ranked assets and update the COF, LOF, and condition assessment in its Plan Update filings.

Mr. Vamos next testified about certain assets that were included in the Rick Model, but were prioritized using other criteria, such as safety, documented performance issues, or the availability of spare parts. These projects include the breakers associated with Relay and Control Modernization, Distribution Power Transformers, Circuit Performance Improvements, and Underground Cable Replacements. He then specified why NIPSCO is not prioritizing breakers associated with Relay and Control Modernization, Distribution Power Transformers, Circuit Performance Improvements, and Underground Cable Replacements based solely on risk rankings and provided rationale for each category.

Mr. Vamos also testified about various projects, their scope, and their primary reason for inclusion.

System Deliverability Projects account for approximately 20% and $281,439,419 (direct capital) of NIPSCO's Plan. He described how NIPSCO identified the System Deliverability investments to include in the 2021-2026 Electric Plan based on NIPSCO's reliability planning criteria and assessment practices. For the transmission system, NIPSCO's planning criteria is aligned with the North American Electric Reliability Corporation ("NERC") Reliability Standards, which includes peak load analyses along with other study scenarios targeted at testing the system under stressful situations (e.g., multiple contingencies at the same time). These criteria help ensure a transmission system that will operate reliably and remain resilient through multiple outages without causing cascading outages or widespread load loss and can accommodate near- and long-term customer load growth. These outcomes support not only NIPSCO's customers, but also the overall reliability of the Bulk Electric System. For the distribution system, changes in electric demand associated with current and future customer growth often times require investment in the form of expanded, upgraded, or additional facilities. These investments are made to ensure sufficient system capacity is available for NIPSCO's customers under peak load conditions when the system is stressed. He noted NIPSCO follows planning criteria used to identify areas of needed improvements under these peak conditions, which call for mitigation plans to be developed when equipment limits are exceeded for normal system operations as well as under the single worst contingency. Distribution operating and design criteria rely on NIPSCO electric line and substation capacity capabilities are based on NIPSCO's line and substation design standards, along with specific equipment manufacturer ratings. He also explained how NIPSCO's Transmission Planning and Distribution Planning groups were involved in developing the selected projects.

As for the projects themselves, Mr. Vamos testified the 2021 and 2022 Transmission System Deliverability projects include the rebuilding of two, 69 kV circuits and the extension of one, 69 kV circuit to a new Distribution Substation, and the 2021 and 2022 Distribution System Deliverability projects include one new distribution substation, the addition of two new power transformers at two existing substations, replacement of one existing power transformer with a larger capacity unit, two new switchgear, the rebuilding of four, 12 kV circuits, and the reconfiguration of multiple 12 kV circuits and feeders to accommodate the aforementioned substation upgraders. These projects address system capacity issues experienced during peak load.

In addition to describing the 2021 and 2022 project, Mr. Vamos explained that NIPSCO has identified and included in the Plan the System Deliverability investments that are needed in future years based on the current planning models and that these future projects are the product of on-going planning cycle iterations. He confirmed the project detail will be provided in a future plan update and that these improvements might change in subsequent planning cycles as NIPSCO's transmission and distribution system changes and as new or growing customers are accommodated. In addition to the specific line projects included in the Plan for 2021 and 2022, NIPSCO anticipates the construction of one new 138 kV circuit in 2024 and five new 69 kV circuits – two in 2024 and three in 2025. In addition to the specific substation projects included in the Plan for 2021 and 2022, NIPSCO anticipates the construction of a total of three new distribution substations – one in 2024 and two in 2026. NIPSCO has also identified the need to construct two new transmission substations which are currently planned in 2025 and 2026.

Grid Modernization Projects account for approximately 26% and $362,054,616 (direct capital) of NIPSCO's Plan. Mr. Vamos testified that NIPSCO developed a series of strategic initiatives designed to develop and enhance the NIPSCO electric system infrastructure. He explained that these initiatives are designed to achieve significant improvements in customer service and electric service reliability, as well as ensure NIPSCO is positioned to offer the services customers will expect from a modern utility. Part of the strategic initiatives includes a new, more robust telecommunications network, and implementation of modern sensing equipment (i.e., DA, SA, and AMI). The telecommunications network and modern sensing equipment will work together with a new DSCADA system to create a network that can identify and isolate faults then restore customers (self-heal). Through the incorporation of Grid Modernization technologies, he stated NIPSCO will be able to provide value to its customers through reduced outage severity and duration improving the customer experience.

Mr. Vamos explained that the Grid Modernization initiative of DA targets the enhanced reliability of NIPSCO's distribution circuits and includes replacement or addition of circuit reclosers and communication equipment. The DA program, which extends beyond 2026, will strategically place approximately 600-700 electronic reclosers on existing circuits over the span of the Grid Modernization initiative. During the course of the 2021-2026 Electric Plan, approximately 515 electronic reclosers will be installed and will be configured for either automated or manual operation aiming to split the circuits into segments that serve approximately 500 customers. He noted that, while DA is a dedicated program, these technologies are also being implemented on other aging infrastructure and deliverability projects.

Mr. Vamos further explained how the Grid Modernization initiative of SA targets to enhance the reliability of NIPSCO's T&D system, as well as improves the visibility into the health of its substation assets. SA is comprised of three categories: (1) transformer monitoring, (2) breaker monitoring/control, and (3) battery monitoring. Transformer monitors will allow for continuous oil analysis and temperature monitoring. Battery monitors will collect data and analyze the health of the batteries. Both of these monitors will allow NIPSCO to gain better health data on the assets allowing for more proactive maintenance and/or replacement. Additionally, he stated distribution class relays on circuits that are receiving DA reclosers will be upgraded to microprocessor relays to better coordinate with the DA reclosers. Similar to the transformer and battery monitors, upgraded breaker relays will allow for better health data on the assets allowing for more proactive maintenance and/or replacement. Again, while SA is a dedicated program, these technologies are also being implemented on other aging infrastructure and deliverability projects.

Mr. Vamos also testified about the communications assets that are planned for replacement. The new grid modernization design includes comprehensive upgrades to NIPSCO's legacy communication assets (e.g., towers, radios, fiber optics, and network configuration) and employs high-capacity digital microwave radio on lattice towers and monopoles, as well as fiber optics links configured in a multi-ring network topology. Using both microwave radio and fiber optics backhaul transport to interconnect and integrate the transport rings into the overall architecture, and establish contiguous, diverse communication paths to adjacent nodes and back to the NIPSCO system control centers. He testified that the design also provides for diverse, redundant paths back to the control centers, as well as provides visibility to distribution substations that do not currently have communications connectivity. Additionally, the new DSCADA system is comprised of a combination of hardware and software that work together with NIPSCO personnel in a control center, which will allow for real-time data processing and supervisory controls to enact the DA and provide NIPSCO with valuable visibility into the status and condition of the transmission and distribution systems.

Mr. Vamos next testified how NIPSCO identified the types of Grid Modernization investments to include in the 2021-2026 Electric Plan and explained their expected benefits. Specifically, NIPSCO evaluated areas of investment that were foundational to the enhancement of NIPSCO's system performance and ability to serve its customers and then used a combination of third-party vendors and collaborative sessions with its peer utilities to establish the performance baseline for implementation of these initiatives. For DA investments, he stated they have the potential to positively impact NIPSCO's reliability performance, as does the broader grid modernization effort. While the IEEE indices referenced in this report have many drivers, weather events specific to NIPSCO's territory are a large contributor. With implementation of the DA program, there is the potential to reduce the impact of these events to NIPSCO's customers. For the SA investments, he repeated the three components discussed above and stated they have the potential to enhance protective scheme coordination between substation breakers and electronic line reclosers; identify the approximate fault location which results in faster restoration times; allow for continuous monitoring to allow for more proactive replacement; allow for more efficient asset operation during periods of heavy load through predictive cooling; and assist in calculating equivalent loss of life from its event history.

Regarding evaluation, selection, and prioritization of communication investments, Mr. Vamos testified this work required external support due to the complexity of future system needs. S&L was engaged to audit NIPSCO's current communication network, review current industry best practices, and provide a report that outlines the needs of NIPSCO's network. He also explained the order of work. The yearly upgrades start with the construction of the main backhaul centering around NIPSCO's communication hubs, and the project plan targets substations (including microwave radio and fiber optics ring nodes) for integration into a multiple ring network topology, which will be anchored at NIPSCO's operational control centers. He noted that the Communication plan will extend past the 2021-2026 Electric Plan and that, similar to the other Grid Modernization efforts, Communications will also be included in any new substation projects, as has been NIPSCO's practice in Electric Plan 1.

Mr. Vamos testified all of the projects included in NIPSCO's 2021-2026 Electric Plan are undertaken for purposes of safety, reliability, grid modernization, or economic development and confirmed that none of the projects are included in the 2021-2026 Electric Plan included in NIPSCO's current base rates. He briefly noted that NIPSCO provided the best estimate of the cost of the eligible improvements, as discussed in detail above. He also explained how the public convenience and necessity requires or will require the eligible improvements included in the 2021-2026 Electric Plan. Specifically, the eligible improvements included in the 2021-2026 Electric Plan are required or will be required to maintain the safety, integrity, and reliability of NIPSCO's transmission and distribution systems consistent with the public convenience and necessity. He concluded by reiterating that the estimated costs of the eligible transmission and distribution system improvements included in the 2021-2026 Electric Plan are justified by incremental benefits attributable to the Plan, as discussed above and outlined in detailed in Confidential Attachment 2-B.

C. <u>Christopher D. Kiergan</u>. Christopher D. Kiergan, West Monroe Partners, LLC, testified in support of the AMI Project. He explained that West Monroe worked with NIPSCO to complete a comprehensive cost-benefit analysis ("CBA") for the electric AMI Project. He explained the purpose of the testimony as describing the general process used in developing the CBA, explaining the structure of the CBA, highlighting the cost and benefit inputs and other information provided to West Monroe by the Company, and supporting and explaining certain Company, customer, and societal benefits that were calculated and that are associated with the AMI Project.

Mr. Kiergan outlined the recent history of AMI adoption, including how over the last several years, AMI has continued to grow as the standard for electric utilities and as a preferred technology when compared to AMR meters. He noted that, while the initial switch from manually read meters to drive-by AMR meters enabled meter reading process efficiencies, several factors are driving utilities to pursue AMI. For example, AMR meters are not equipped with remote service connect/disconnect switches (requiring these service orders to continue to be performed manually), do not provide interval energy usage data or demand readings (which enable time of use and other rate options), and lack visibility into near real-time operational conditions (which enable insights into outage awareness, voltage sags and swells, meter temperatures, and meter tampering that could indicate theft). He also explained that AMI meters provide this breadth of functionality and enable further outcomes such as improved load forecasting and power quality management which is increasingly necessary given the growing complexity of two-way power flow on the grid as distributed energy resources ("DERs") are adopted and encouraged in the market.

Mr. Kiergan testified that West Monroe has analyzed overall AMI adoption rates in the United States. According to the U.S. Energy Information Administration ("EIA"), AMI adoption, at the end of 2019, has reached 94.8 million meters or 60.3% of all installed meters in the United States. Additionally, he explained that the growth rate of AMI has been consistent over the last five years as the number of installed AMI meters in the U.S. has grown annually at a rate between 9% and 14%. Further estimates, based on AMI deployments currently underway, project a continued 9% growth in 2020, with the total AMI meters installed reaching 107 million meters and percent adoption hitting approximately 68.0%. He noted that this demonstrates that AMI continues to progress with more electric utilities adopting this technology each year and multiple utility deployments in progress.

Mr. Kiergan continued by explaining the broader policy and/or technology changes that are also pushing electric utilities to adopt AMI technology. He outlined the following industry changes and how they relate to AMI: (1) distribution automation, (2) proliferation of electric vehicles ("EV"), (3) installation of DER, and (4) customer expectations and empowerment. He also briefly discussed cyber-security related concerns and how AMI technology can be developed and implemented in a manner to protect customer data.

Mr. Kiergan explained the benefits of the AMI Project exceed the costs over a 15-year horizon. The CBA thus represents a positive business case from a financial perspective, providing over $300 million in benefits, which represents net benefits of approximately $53 million on a nominal basis.

In addition to these quantitative benefits, Mr. Kiergan confirmed there are additional, qualitative benefits associated with improving the customer experience, enabling future customer and utility operations programs, reducing greenhouse gas ("GHG") emissions associated with reducing truck rolls and drive-by meter reading (quantified, but not included in the CBA results), and increased safety. He noted the AMI Project also provides a societal economic and jobs benefit which has been incorporated into the overall calculation of jobs created by the 2021-2026 Electric Plan.

Regarding the methodology utilized to develop the CBA, Mr. Kiergan explained that West Monroe utilized its proprietary AMI CBA tool, a detailed Microsoft Excel spreadsheet analytical model created and managed by West Monroe. He also provided an explanation about the model. Specifically, he testified the model, capable of complex calculations and sensitivity analyses, has been continuously refined in terms of calculation methodology and specific benchmark inputs through its use at multiple utilities.

Additionally, Mr. Kiergan testified that the CBA was tailored for NIPSCO parameters, including the application of AFUDC, contingency, corporate overhead, materials tax, and labor inflation to only specific cost categories and cost elements. He further explained West Monroe leveraged an established methodology for valuation of the projected costs and benefits for large grid transformation projects. In general, the methodology incorporated both inputs from NIPSCO and, in areas where NIPSCO had less experience, inputs from West Monroe benchmarking data derived from several recent AMI business case analyses. In terms of costs in the CBA, West Monroe coordinated with NIPSCO to capture and input capital and O&M expenses associated with delivering the AMI Project, including internal and external labor, equipment, software, hardware, and services. For each cost component, NIPSCO provided cost data inputs, unit costs, assumptions, and other information. West Monroe then benchmarked the cost inputs based on industry experience and perspective from similar efforts. He affirmed that the benchmarking process helped balance scope and investment to match anticipated benefits based on the experience of other utilities.

Mr. Kiergan also testified about where NIPSCO was in the process of project development. Specifically, because NIPSCO is just initiating the AMI Project, it did not have vendor-supplied cost information for certain components. For these components, including AMI meter costs, AMI communication asset costs, and a Meter Data Management System ("MDMS"), West Monroe used benchmark data from several recent AMI business cases and deployments to estimate the scope needed and the corresponding costs. The cost information served as one input to the CBA, which also considers projected annual costs and ongoing operational impacts, and applies inflation and other escalation factors, as appropriate.

As for the benefits calculations, Mr. Kiergan confirmed that the nature and value of the customer benefits from the AMI Project have been provided by NIPSCO and evaluated by West Monroe based on West Monroe's experience and industry benchmarks. The CBA results provides a summary of the categories of benefits included in the CBA. In line with the TDSIC Statute, he noted that the AMI Project is undertaken for the purposes of modernizing NIPSCO's system and improving safety and reliability. From a qualitative perspective, Mr. Kiergan explained benefits can be thought of as satisfying four primary goals: (1) Enhancing the Customer Experience, (2) Improving Safety and Reliability, (3) Improving Operating Efficiencies, and (4) Unlocking the Potential for Further Utility Transformation. When specifically focusing on the quantitative benefits calculated in the CBA, at a summary-level, the benefits are categorized as (1) O&M and Expense Reduction, (2) Avoided Capital, (3) NIPSCO Cost of Service Reduction, and (4) Customer.

Regarding the timeframe over which costs are expected to be incurred, Mr. Kiergan explained deployment costs associated with the AMI Project, including both capital costs and one-time O&M expenses, are scheduled to be incurred during the 6-year period of 2021-2026. He outlined the timeline of implementation as follows. After pre-planning and regulatory engagement in 2021, 2022 would consist of detailed planning, issuance of request for proposals, and major decisions around the AMI system and information technology ("IT") systems required in the AMI Project. In 2023, the required IT systems and integrations would be deployed and an initial deployment of an estimated 3,000 meters would be executed and evaluated to test and optimize deployment and operational processes ("Initial Deployment"). Full deployment of almost 500,000 meters would then be conducted during 2024-2026. He then testified about the purpose of the Initial Deployment. While AMI is a proven technology, AMI deployment at NIPSCO will still require tailored deployment processes, unique integrations between new and existing IT and Operations Technology ("OT") systems, and a method of testing and refining processes ranging from supply logistics to meter and communication asset deployment to meter activation in the AMI Headend System and MDMS to moving data from the meters ultimately to billing, outage management, and customer portal applications.

With respect to benefits calculation, Mr. Kiergan explained benefit realization for customers will begin as soon as the AMI Project meter deployment begins in 2024 and will continue to be delivered for many years to follow. With the associated IT systems and integrations in place prior to meter deployment, as an AMI meter is installed on a customer's premises, the functionality driving benefits is operational. Therefore, the CBA accounts for deployment dates and a 15-year horizon. In other words, once an asset is deployed, the benefit stream tied to it is projected to be realized only from that starting point through 2036, the ending point of the 15-year CBA. While 15 years is longer than the period covered by the 2021-2026 Electric Plan, he explained that this is a potentially conservative approach, as benefits will continue to be realized throughout the entire useful life of the AMI Project assets, which will in many cases be well over 15 years.

Mr. Kiergan further testified the role West Monroe played in calculating the benefits within the CBA. For each scope area, West Monroe facilitated working group workshops with NIPSCO to identify the specific inputs and data points that would be needed to project the calculation of benefits. In some cases, the benefit values were provided directly to West Monroe and input into the analysis without modification. In other cases, information was provided and additional work was undertaken using established tools, relevant industry knowledge and experience, benchmarking, and other analyses to complete the projection of benefits and incorporate them into the CBA.

Next, Mr. Kiergan summarized the investments included in the CBA. Detailed annual cost information for the AMI Project as pertinent to the CBA is provided in the CBA Results. The West Monroe CBA calculates costs in terms of capital costs and one-time O&M expenses associated with the deployment of the AMI Project during 2021-2026. He explained capital costs during AMI Project deployment are divided between direct and indirect costs. Direct capital costs were calculated to be $145.5 million.

Mr. Kiergan also outlined the O&M costs associated with the AMI deployment. One-time O&M expenses during deployment of the AMI Project (2021-2026) were calculated to be $10.0

million. Primary activities that drive these expenses relate to: (1) customer engagement with respect to the impact and benefits of AMI and specific AMI deployment information; and (2) project management and change management / business readiness associated with developing AMI operational processes. Additionally, as part of the CBA, recurring O&M expenses were calculated and included in the overall analysis of costs and benefits associated with the AMI Project. However, these expenses have been excluded from this filing as NIPSCO is not seeking recovery of recurring O&M expenses through the TDSIC. Recurring O&M expenses will be addressed through normal rate making processes.

Mr. Kiergan next explained the four primary categories of quantified benefits attributable to the AMI Project, including: (1) O&M and Expense Reduction, (2) Avoided Capital, (3) NIPSCO Cost of Service Reduction, and (4) Customer.

For O&M expense savings, he explained West Monroe worked with NIPSCO to identify areas of O&M expenses that would be eliminated or reduced as a result of investments within the scope of the AMI Project. NIPSCO provided these O&M expense savings details for areas such as AMR meter reading and meter servicing costs, AMR and meter servicing vehicle costs, avoided truck rolls associated with "found-on" events, improvements in outage locating, and other operational improvements. The total benefits associated with O&M expense savings are approximately $164.9 million over the next 15 years.

For avoided capital benefits, he testified West Monroe worked with NIPSCO to identify the previously planned investments that would be avoided or deferred as a result of investments within the scope of the AMI Project. NIPSCO provided details for a wide range of investment types that would be avoided or deferred, including purchases of AMR meters and collectors, AMR IT systems, and meter reading vehicles. The total benefits associated with avoided/deferred capital are approximately $8.8 million over the next 15 years.

For cost-of-service reduction benefits, he again explained how West Monroe worked with NIPSCO to identify the current and projected levels of energy diversion or theft associated with meter tampering and the current levels of consumption on inactive meters. By leveraging the functionality of AMI, specifically the use of the remote connect and disconnect switch, and the ability to identify meter tampering activities or malfunctioning equipment more accurately, utilities across the U.S. have experienced significant reductions in energy diversion and consumption on meters for which an account is in an inactive status. Projected savings for NIPSCO were based on similar programs and technology deployments, and the total benefits associated with energy diversion and consumption on inactive meters are approximately $33.1 million over the next 15 years.

Finally, for the customer benefit, he explained this category is defined as those benefits that have an impact on customer spend and are comprised of two components: (1) Customer Electric Demand Side Management ("DSM") Benefits and (2) Customer Reliability Improvement. For the former, deployment of AMI (along with a modernized Customer Portal that is not part of the Plan) will enable advanced channels of communication with customers. Among the information that will be accessible to customers via the Customer Portal is the presentation of the interval energy usage data that is made available via AMI. Research has shown that customers with AMI meters and enhanced customer portals reduce their energy consumption. Within the CBA, it was estimated that 10% of customers will be actively engaged and adjusting their behavior, and that the impact of that will be a 1.1% reduction in energy usage for those customers in the steady state, following AMI and the Customer Portal deployment. For the latter, there are several sources of the reliability improvements in the overall Plan described by Witness Vamos, including a reduction in the number of customer interruptions resulting from DA projects. He noted there will be additional impacts on outages resulting from AMI deployment, but these impacts will be seen in a reduction in the duration of the outages or in the customer minutes of interruption. With AMI providing more complete information on customers impacted by an outage, or remaining out after initial restoration work is completed, NIPSCO will be able to pinpoint the location of the outage more quickly, resulting in a decrease in the overall duration of the event. In this area of improvement, NIPSCO provided projections regarding the percentage of total outage time spent locating outages and the relative amount of improvement that could be realized. West Monroe then input NIPSCO's company-specific information into the DOE ICE Calculator, to calculate the value of the improved reliability benefits to customers in dollar form. The resulting calculation captured the benefits from AMI-related reliability improvement by year in the CBA and were included in the CBA based on the timing of planned AMI Project investments and the asset life of the related assets that drive the benefit and is estimated to be approximately $98.7 million over the next 15 years.

Mr. Kiergan concluded this section by explaining that an intentionally conservative approach to many of the benefits assumptions was taken in the CBA. He explained why it is more appropriate and prudent to conservatively estimate benefit components of the CBA. First, many of the planned investments within AMI Project are foundational by nature, and not yet installed. Because of this, given the unique nature of any company's service territory, it is appropriate to take a measured approach to projecting elements of the analysis that drive certain benefits, particularly those associated with customer behavior and program adoption. For this reason, a blend of industry benchmarking and Company history with customer programs was used to develop certain benefit projections.

Regarding economic impact, Mr. Kiergan explained that NIPSCO worked with West Monroe to develop the projected impact of the AMI Project on the economy, including creation of jobs and overall stimulus. The AMI Project inputs were combined with inputs from the other components of TDSIC investment. Total TDSIC impact on the economy was then calculated using IMPLAN, an economic impact assessment software system. The IMPLAN software was subsequently run using just the AMI investment inputs, resulting in estimated economic impact to the state of Indiana of $260.62 million (direct effect) to $490.21 million (total effect). Looking at the impact of AMI Project investment at a national level, IMPLAN estimates an economic impact of $323.40 million (direct effect) to $1,303.41 million (total effect).

Mr. Kiergan then explained the additional or societal benefits attributable to the AMI Project, including why certain benefits were not included in the "total" for the baseline CBA calculation, and are instead listed as "societal." For additional context, he noted that while West Monroe and NIPSCO are confident the AMI Project will produce some level of societal benefits, it was deemed appropriate not to monetize these benefits and to exclude them from the baseline cost-benefit comparison to provide a customer-focused assessment of the planned investments.

Again, for reference, the societal benefits include a reduction in GHG emissions and overall economic impact of the planned investments. The GHG emissions relate to reduced vehicle miles associated with meter reading and fewer total megawatt hours ("MWh") of electric generation. Using benchmarks for the cost of CO_2, the reduction in GHG emissions was estimated to provide $5.2 million in benefits.

Next, Mr. Kiergan testified about further benefits that are not easily quantified in terms of economic value. One prime example is the significant improvement to the customer experience that will be delivered by the AMI Project. The increased level of customer choice, engagement, and satisfaction of customers that will result from these investments are difficult to assign a value to, but he noted NIPSCO is confident that they are real and in alignment with what customers are demanding. Additional benefits can come from the use of AMI as the foundational basis for follow-on programs, including customer-focused programs, programs to increase safety and reliability, and programs to enable a more efficient grid. These benefits would require additional investment to achieve but would all not be possible without AMI as the foundation. While not quantified as part of the CBA, he stated the contribution of these qualitative benefits is important and therefore relevant to the overall CBA results and further support the reasonableness of the AMI Project investments.

Mr. Kiergan also outlined certain follow-on programs that could be enabled by AMI, as it is a foundational technology that provides data and functionality that can be used to offer follow-on programs in the years to come. He stated that, at this time, NIPSCO has not analyzed the additional costs or resulting benefits of any follow-on programs and has not developed a plan addressing what follow-on programs might eventually be offered. Additionally, while each of these programs may not be implemented in the near term, none of them will be possible to implement without the foundational investment in the AMI Project. These additional programs include: (1) Enhanced Customer Programs, such as (a) High Bill Alerts, Bill Date Selection, Prepaid Billing, (b) Advanced Rate Options (Critical Peak Pricing, Peak Time Rebate, Time of Use), (c) DER Net Metering & EV Charging Rates, and (d) Enhanced Demand Response / Energy Efficiency Programs; (2) Improved Reliability & Safety, such as (a) Hot Socket Detection, (b) Interruption Trending, (c) Vegetation Management, (d) Improved Power Quality, and (e) Transformer Loading Analysis; and (3) Efficient Distribution System Management, such as (a) Advanced Load Profiling, (b) an Improved Connectivity Model, (c) Open Neutral Analysis, (d) Incremental Conservation Voltage Reduction/Volt Var Optimization through AMI Voltage Sensing, (e) Optimized DERs/Renewables/Charging Infrastructure through Demand Insights for Load and Capacity Forecasting, and (f) Smart Inverters.

Mr. Kiergan concluded with a discussion on concerns related to obsolescence, noting utilities should always carefully weigh and consider investments, especially large-scale capital expenditures, using a number of lenses, including consideration of possible obsolescence of technology. He explained it is important to maintain flexibility and forward compatibility as key criteria for the selection of software, hardware, and other field devices associated with the continued modernization of the grid. He testified NIPSCO has demonstrated that these are priorities, via their plans to leverage an iterative planning and implementation process for field devices and other technologies that rely on the ongoing assessment of new and emerging capabilities that deliver the desired functionality and targeted customer benefits. Also, NIPSCO will place considerable value on forward compatibility of the planned investments during vendor evaluation and the planning process and believes that the investments within the AMI Project will deliver long-lasting and sustainable benefits consistent with the CBA.

D. <u>Matthew G. Holtz</u>. Matthew G. Holtz, NiSource Corporate Services Company, Director Asset and Risk Management, testified in support of the proposed AMI Project. He noted he is part of the team that helps to determine how NIPSCO will plan and operate its electric system in a changing environment where government policy and customer preferences are increasing the reliance on NIPSCO's electric system. He then noted some of these future changes include greater customer electrification (including EVs) and the anticipated increased penetration of DERs, including potential participation by these DERs in the wholesale energy markets at the Midcontinent Independent System Operator, Inc. ("MISO"). He stated AMI is viewed as a tool to help ensure NIPSCO is able to successfully support these changes.

Mr. Holtz next described NIPSCO's current metering infrastructure, which is currently AMR metering technology. He noted that while NIPSCO has realized efficiencies from implementation of AMR technology, NIPSCO needs to modernize its metering technology to AMI to operate as a modern electric utility and be able to respond to and serve its customers' changing needs. For example, as the push for electrification continues, the visibility enabled by AMI will allow NIPSCO to more efficiently plan for and operate its system in a way that meets customers' expectations, and also realize significant, additional benefits.

Mr. Holtz then provided an overview of NIPSCO's AMI Project, which includes deployment of AMI meters and related communications technology to the vast majority of electric meters in NIPSCO's electric service territory, including the replacement of over 479,000 current electric AMR meters, plus any growth that occurs through the end of deployment. He explained that, at its core, AMI consists of an array of integrated meters, communications networks, and IT systems that enable two-way communication between a utility and customer meters. Beyond technology, an AMI program is also an investment in people and processes that directly enables operating efficiencies, improved reliability/safety, and enhanced customer outcomes while establishing a foundation for transformation as NIPSCO leverages AMI to respond to the demands on a modern electric utility.

As for program development and execution, he testified NIPSCO will select a communications system solution, comprised of a field-area network of data collectors and communications from meters and backhaul communications from data collectors to the AMI Headend System, through the evaluation of competitive Request for Proposals ("RFP") bids. This evaluation will align with procurement best practices and will determine the most effective technology solution for NIPSCO's AMI system. Mr. Holtz explained the total costs of the primary communications system solutions alternatives are generally similar, and costs modeled as part of the AMI Project CBA have been calculated using standard cost benchmarking. He noted the proposed project will include an MDMS, which performs the validating, editing, and estimation analysis and calculates the billing determinants for each customer. This data is then sent from the MDMS to the Customer Information System ("CIS") for customer billing.

As further discussed in Section 2.5 of the 2021-2026 NIPSCO Electric AMI Business Case, NIPSCO plans to run an RFP process and subsequent analysis to determine the AMI communications solution best suited for its service territory. With respect to timing, Mr. Holtz testified that the roll-out of AMI will provide NIPSCO with greater visibility into distribution system operations and capabilities for enhanced planning activities (including load forecasting) and other future benefits, as the AMI data will provide NIPSCO the insight needed to better understand its customers, for example being able to more accurately model / forecast loads, allowing NIPSCO to design effective future offerings, and provide insights to NIPSCO's customers. Additionally, NIPSCO will be able to better understand how its customers use energy, which will address one of the suggested enhancements recommended in the Final Director's Report for NIPSCO's 2018 Integrated Resource Plan ("IRP") dated February 10, 2020.

Mr. Holtz emphasized that AMI is also foundational for NIPSCO to successfully navigate an environment where customers are pursuing greater electrification, including the increasing penetration of EVs and DERs. AMI will provide the sub-hourly interval, real-time meter data to reliably balance energy supply and demand, settle for energy supplied to the system at the time it occurs, and properly respond to customer demand increases that will come with higher adoption rates of EVs. Additionally, he explained AMI aligns with other NIPSCO initiatives driving system modernization and enhanced customer value that are more powerful when viewed together than as distinct parts, especially when coupled with the rich data that AMI provides to NIPSCO and its customers to utilize. With other components of the TDSIC filing, especially the grid modernization efforts, he noted there are synergies as more sensors and controls are deployed that are complimented by AMI's capabilities to improve power quality analysis/mitigation and transformer mapping/analytics, for example. Separate from the planned investment in AMI, systems like Oracle Network Management System for outage management are being upgraded; a new "Customer Portal" and mobile application are being stood up; analytics architecture and governance are planned for future state innovation; new customer payment programs are being developed; and a market potential study has shown a pathway for demand response.

Mr. Holtz also testified that AMI provides benefits in line with the TDSIC Statute. Specifically, the Indiana General Assembly amended the TDSIC Statute to explicitly allow for grid modernization projects (including advanced metering infrastructure) to be included for recovery in approved TDSIC plans, indicating a recognition of the benefits associated with these kinds of projects. He stated AMI holds great promise to improve safety, promote reliability, enable system modernization, and drive economic development in accordance with the tenets of the TDSIC Statute. From a cost effectiveness point of view in relation to TDSIC purposes and stakeholders, AMI functionality will enable a core set of operational efficiencies to be realized, provides benefits directly to customers, and unlocks future transformative programs to potentially be pursued by NIPSCO. To be prepared, he said NIPSCO has developed a holistic implementation plan and costs for the people, processes, and technology needed to achieve the targeted AMI program outcomes.

After noting that Mr. Kiergan provides much more detail on the expected benefits of the AMI Project, Mr. Holtz provided an overview of expected benefits as well. He also testified NIPSCO's overarching goal for the AMI Project: to position NIPSCO to be able to provide the service its customers expect from a modern electric utility company. In addition to the system benefits, he also noted the primary, tangible goals of the AMI Project are to enhance customer experience, increase safety and reliability, and improve field workforce efficiency, while providing the foundation for additional potential offerings and improvements.

Mr. Holtz also explained that, currently, without AMI technology, NIPSCO's insight into customers' energy usage is limited. For example, during the last 12 to 15 months, COVID has driven changes to customer and customer class usage, shifting some load from commercial customers to residential customers with a higher population working from home. He noted that NIPSCO's current technological capabilities are limited relying on monthly data points and more generalized usage patterns, allowing only limited insight into customers' energy use changes. However, AMI will allow NIPSCO to better understand its customers and their usage patterns. He further explained this more granular look into its customers' daily usage patterns will allow NIPSCO to build more accurate load curves for NIPSCO's different customer classes, which will enable NIPSCO to produce more accurate load forecasts into the future, which is an important improvement as customers' overall electric usage is changing with the increased penetration of EVs and DERs, and a trend toward electrification in general.

Mr. Holtz continued explaining how changes in the industry are pushing NIPSCO to implement AMI at this time. For example, with higher EV penetration levels, the charging of these vehicles could strain the NIPSCO electric system if not closely monitored and prepared for. He cited to certain statistics about increasing EV adoption and load growth and noted that incremental load additions at this scale were not planned for in the past 50 years as utilities have been installing service level equipment to serve their customers. Without the visibility that AMI provides, NIPSCO will need to make assumptions on its customers' future usage levels and patterns as the electrification trend continues, potentially leading to the upgrade of service level equipment prematurely. He testified AMI will potentially enable NIPSCO to monitor actual customer usage levels and patterns throughout the day, season to season, giving NIPSCO the ability to upgrade service level equipment when the need is reached, but, without AMI data, NIPSCO would also not be in a position to explore other methods of incenting customers (including EV customers) to change their electric usage patterns (e.g., time of use rates) to off-peak times, leveling load curves and potentially avoiding system upgrades or resource capacity additions.

Mr. Holtz also testified how with the reductions in installation cost for customer level resources, NIPSCO and the industry in general have seen an increase in installed DER capacity in their footprints, with one of the main drivers of this growth being solar panel installations. For example, under NIPSCO's net metering program, NIPSCO's system saw growth from 811 kW of installed solar capacity in 2015 to 28,155 kW by the end of 2020. Therefore, AMI will be key to enable a smoother transition to an environment with a continued higher penetration of customer-owned, smaller scale generation. He also noted the more granular AMI data could potentially support the settlement of energy in periods that would measure when the energy injection occurs, as opposed to AMR which provides very limited data points, as this granular level data is foundational to allow for DER aggregation and participation in the MISO Energy Market, as enabled in FERC's Order No. 2222. In order for a resource to participate in the MISO Energy Market, he said resource monitoring and sub-hourly meter sampling are required. AMI technology could support this option for customers, whereas existing AMR metering technology cannot.

Next, Mr. Holtz spoke to NIPSCO's plan to secure customer data and the network that will be built out as part of AMI. He explained NIPSCO's IT and OT functions are centralized as part of NiSource's IT department, and NiSource IT plans to protect customer and company data associated with AMI that is contained in the NiSource environment in the same fashion that it protects this data today using proper firewall, monitoring, and controls to ensure the protection of this data. Similarly, when it comes to the new network and external vendor interfaces associated with AMI, NiSource IT will again approach this as it does with the critical systems that it supports today. He also confirmed vendor security controls will be integral as part of the negotiation of the AMI system on the front end to ensure that the vendor NIPSCO selects will have the proper security controls in place to ensure they are protecting NIPSCO customer data as the company would. In addition, NiSource IT again will secure its interfaces with the vendor as it does today with firewall, monitoring, and controls that is standard with other critical systems.

Mr. Holtz also testified about AMI Project execution, which is estimated to occur over the next five years, with the vast majority of customer meters being replaced in the 2024–2026 timeframe. Currently, in 2021, NIPSCO is conducting a series of pre-planning activities to begin developing the governance structure and high-level plans (communications, customer engagement, security, etc.) that will guide the project. In 2022, the AMI Project will transition to initial design, issuance of RFPs for the AMI system, MDMS, and related integrations, and formal project management governance. After that, the focus will be on the IT systems, executing these investments prior to the initial implementation of roughly 3,000 meters in 2023. During the period of initial implementation, processes and employee training will be revised, tested, and updated to have all processes optimized for full deployment.

Mr. Holtz overviewed the costs and benefits associated with the AMI Project as well. He explained that NIPSCO estimates that it will need to invest $145.5 million (direct capital) between 2021 and 2026 to build out its AMI system, which includes the cost of AMI meters, AMI communications network, installation labor, and a comprehensive list of necessary investments needed to enable the AMI benefits, such as cyber security protections. For maintenance capital expenditures (e.g., replacement meters, new customers, etc.) after the AMI system is in service, $4.3 million (direct capital) in ongoing capital expense is estimated. In terms of one-time O&M expense, the CBA estimates a total of approximately $10.0 million needed as part of project execution. Recurring O&M expenses after project deployment is complete is estimated at $69.9 million between Years 2021 and 2036. Lastly, indirect capital costs were estimated for Years 2021 to 2036 to account for capital costs associated with corporate overhead and AFUDC, totaling $22.2 million. In terms of quantified value, Mr. Holtz explained NIPSCO has estimated $305.5 million in total benefits between the years 2021 and 2036, as discussed further below and by Witness Kiergan.

Mr. Holtz outlined the primary capital investment categories, which are: (1) AMI meters and installation labor, (2) AMI communications network equipment and installation labor, (3) MDMS and other systems, and integrations, and (4) cyber security protection. He did the same for O&M expense categories, which include one-time expenses and recurring expenses. He reiterated that NIPSCO is only seeking recovery of the "one-time expenses," which are estimated to be approximately $10 million over the entire TDSIC Plan period. Recovery of these expenses is appropriate because this work is directly tied to AMI Project implementation and incremental to (or different than) any O&M expenses that NIPSCO recovers in its base rates and charges.

However, accounting rules require that these expenses be classified as O&M expenses rather than capital costs even though these expenses will be incurred as part of the AMI Project execution. Consistent with the TDSIC Statute where "operation and maintenance expenses" are defined as a component of "TDSIC costs" in sub-section 7, he testified it is appropriate to recover these costs through the TDSIC tracker.

Mr. Holtz also discussed the anticipated benefits associated with the AMI Project. The AMI Project benefits fall into three broad categories: (1) NIPSCO Operational Benefits; (2) Customer Benefits; and (3) Societal Benefits.

Mr. Holtz concluded by explaining how NIPSCO will address situations where a customer does not want an AMI meter installed and how NIPSCO is considering AMI technology for gas customers. Regarding the former, he stated NIPSCO understands that some customers may, for various reasons, have concerns about the installation of an AMI meter on their premises. Thus, he confirmed that, as it does for its AMR meters, NIPSCO will continue to allow customers to "opt out" of installation of an AMI meter if they so choose. Regarding the latter, he stated NIPSCO's approach to AMI for its combined (electric and gas) customers and gas-only customers is still being developed. He explained NiSource is investigating AMI solutions across all of its six operating companies, including NIPSCO gas. Although more granular gas usage data is important to both NIPSCO and its customers, the NiSource team is focused on finding a solution that also provides safety benefits to NIPSCO's gas customers. Although technological improvements in this area are still underway with meter manufacturers, he testified NiSource is actively investigating and testing solutions to ensure that effective metering options are targeted. Additionally, he stated the NIPSCO electric AMI Project team is actively coordinating with the team investigating gas AMI solutions to include gas functional requirements as part of the electric AMI technology evaluation process, primarily in the area of AMI communications network and MDMS. This will provide the opportunity for NIPSCO to investigate the potential benefits of utilizing electric AMI assets to support gas AMI for combined gas and electric customers in its electric service territory in the future, providing efficiencies down the road when gas AMI is deployed.

E. <u>Erin K. Meece</u>. Erin K. Meece, NCSC Lead Regulatory Analyst, described NIPSCO's accounting and ratemaking treatment to be used to record and recover costs associated with NIPSCO's 2021-2026 Electric Plan. She explained NIPSCO anticipates recovering approved capital expenditures and TDSIC costs associated with the 2021-2026 Electric Plan through its existing electric TDSIC mechanism.

Ms. Meece described NIPSCO's currently approved ratemaking treatment for recovery of approved capital expenditures and TDSIC costs, including how (1) the TDSIC revenue requirement is calculated, (2) the return on capital costs and expenses included in the revenue requirement are calculated, (3) NIPSCO includes the reconciliation of costs in the revenue requirement calculation, (4) NIPSCO defers, until recovery through the TDSIC, 80% of the post in service TDSIC costs of the TDSIC projects, including carrying costs and pretax returns, depreciation, O&M and taxes, and (5) NIPSCO treats the remaining 20% of TDSIC capital expenditures and costs that are not included for recovery through the TDSIC adjustment factor. She also discussed NIPSCO's approved CWIP ratemaking treatment related to the recovery of financing costs incurred during the construction of capital projects, as well as recovery of PISCC incurred in connection with TDSIC projects.

Ms. Meece further testified NIPSCO recovers the depreciation expense, and property tax expense on a historical basis. She noted that NIPSCO typically includes six months of actual expense in each adjustment proceeding after such costs have been incurred. Once calculated, NIPSCO reduces the revenue requirement related to the recoverable expenses to 80% in accordance with the TDSIC Statute. With respect to reconciliation of costs in the revenue requirement calculation, she explained that in each TDSIC tracker filing, the revenue requirement includes the variances associated with the under- or over-collection of the revenue requirement approved in a previous TDSIC tracker filing and actual revenue received from customers for the associated period.

Ms. Meece explained that NIPSCO defers and recovers 80% of the PISCC, including carrying costs and pretax returns, depreciation, and property tax expense associated with its approved TDSIC projects, through the TDSIC adjustment factor. This is done through a regulatory asset until such costs are recognized for ratemaking purposes through NIPSCO's TDSIC adjustment factor or included for recovery in NIPSCO's basic rates and charges in its next general rate case. For the remaining 20% of TDSIC capital expenditures and costs that are not included for recovery through the TDSIC adjustment factor, she explained the provisions of Ind. Code § 8-1-39-9(c) and noted that NIPSCO defers, as a regulatory asset, 20% of such costs including depreciation, pretax returns, AFUDC, PISCC, and property tax expenses and requests to recover those costs as part of NIPSCO's next general rate case. Additionally, NIPSCO records ongoing carrying charges based on NIPSCO's WACC on these costs until the costs are included for recovery in NIPSCO's basic rates and charges in its next general rate case.

For depreciation, Ms. Meece further explained NIPSCO depreciates the TDSIC capital expenditures according to each asset's designated FERC account classification. Upon being placed in service, then NIPSCO depreciates each asset according to the FERC account composite remaining life approved in the Commission's most recent electric rate case order (Cause No. 45159). She also testified NIPSCO allocates the transmission and distribution system revenue requirements consistent with the revenue allocation approved by the Commission in NIPSCO's most recent base rate proceeding and recovers through a volumetric factor calculated in each TDSIC tracker filing.

Ms. Meece also testified to NIPSCO's proposed changes to its approved ratemaking treatment. Specifically, NIPSCO proposes to use the same approved methodology for calculating the revenue requirement associated with the 2021-2026 Electric Plan, except that NIPSCO is proposing to (1) recover projected depreciation and property tax expenses, (2) exclude depreciation expense related to plant retirements resulting from the new TDSIC investments, and (3) recover O&M expenses. Ms. Meece explained that NIPSCO is proposing to include projected depreciation and property tax expense to reduce the regulatory lag that occurs when recovering these costs on a historical basis and that the projected expenses will also be reconciled to actual amounts in a future filing. She noted any variance between the projected and actual revenues will be recovered from or passed back to customers in that future filing. She also confirmed that this is the same process that the Commission approved in Cause No. 45330-TDSIC-1 for use in NIPSCO's gas TDSIC tracker filings (45330-TDSIC-X), Cause No. 45007 for use in NIPSCO's gas Federally

Mandated Cost Adjustment filings (45007-FMCA-X), and Cause No. 44340 for use in NIPSCO's electric Federally Mandated Cost Adjustment filings (Cause Nos. 44340-FMCA-X). Therefore, approval of this proposed change will allow NIPSCO to realize some efficiencies, as it will align the recovery of depreciation and property tax expenses across all these filings. She continued by noting that depreciation and property tax expenses will be based on fixed, known, and measurable utility plant in service balances included in each filing. She testified that NIPSCO's methodology is consistent with the methodology approved for Indianapolis Power & Light Company's TDSIC proceeding (Cause No. 45264-TDSIC-1) and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.'s TDSIC proceeding (Cause No. 44910).

Ms. Meese testified NIPSCO is proposing to include a reduction to depreciation expense representing the depreciation expense associated with the retirement of assets replaced by TDSIC investments. Specifically, given that the retirements will lag the placement in service of the new asset, she said it is necessary to estimate the amount of the retirements. NIPSCO is thus proposing to use a representative and historical method that relies on a three-year average retirement rate by FERC account (the "retirement rate") to determine the depreciation reduction adjustment to be applied to its recovery of depreciation expense in its TDSIC tracker filings. The source of this information is NIPSCO's FERC Form 1. The retirement rate is then applied to the amount of the TDSIC investments, resulting in a value determined for retirement assets by FERC account. Next, NIPSCO then applies the depreciation rates as approved in NIPSCO's most recent electric rate case to the retirement values by FERC account to determine depreciation expense. She noted the amount of depreciation expense represents the values to reduce the recovery of depreciation expense associated with the 2021-2026 Electric Plan.

Ms. Meece further testified the use of a three-year average is reasonable and sustainable, and also addresses the difficulty of identifying the precise assets retired (as a result of the lag previously mentioned). As for the effect of this reduction to depreciation expense, it will decrease the revenue that would otherwise have been recovered through the TDSIC tracker. This approach nets depreciation expense to reflect the retirement of certain assets as a result of the 2021-2026 Electric Plan. She supported NIPSCO's request by testifying that: (1) NIPSCO's methodology represents an approach grounded in NIPSCO's actual, historical experience to determine a reasonable retirement rate, as the historical amounts are available in public forms submitted to the Commission; (2) this approach benefits customers because the highest capital amounts during the test period are used in the calculation, as opposed to using only replacement assets, ratably placed in service, for the revenue requirement months, thereby increasing the depreciation expense associated with retirement assets and therefore are likely to provide a larger reduction to the TDSIC revenue requirement compared to trying to estimate the depreciation expense associated with specific retired assets; (3) the proposed methodology is reliable and auditable because it relies on data submitted annually to the Commission. NIPSCO follows the FERC method of accounting for fixed asset additions, retirements, and associated depreciation expense by FERC account asset group. The proposed methodology aligns with the FERC method by reflecting actual history and reducing variabilities over time by using a three-year average to be representative of NIPSCO's retirement experience for each FERC account; (4) NIPSCO's proposed methodology will mitigate these effects while also representing a simplified method that includes information that is easily accessible and auditable; and, finally, (5) this is the same methodology that NIPSCO proposed and the Commission approved for NIPSCO's gas TDSIC Plan (Cause No. 45330).

With regard to recovery of O&M expenses, Ms. Meese stated that, consistent with the definition of "TDSIC costs" in section 7(2) of the TDSIC Statute, NIPSCO is proposing to include the recovery of O&M expenses incurred with respect to eligible transmission and distribution system improvements through its TDSIC. She noted that the only O&M expenses included in the Plan are actual O&M expenses associated with the AMI project included in the 2021-2026 Electric Plan and that NIPSCO requests ratemaking treatment of these O&M expenses to defer as a regulatory asset.

Ms. Meece provided an overview of indirect capital costs and the different components included in this category. She testified that historical trends were used to set the Plan estimated indirect percentage at 13% and AFUDC at 3%. However, once Plan execution begins, she said NIPSCO will only seek recovery of actual indirect capital and AFUDC costs incurred. She also explained that NIPSCO's inclusion of these indirect capital costs and AFUDC is consistent with NIPSCO's overhead capitalization and AFUDC methodologies which have been in place for years including during the test year used in NIPSCO's last general electric rate case.

Ms. Meece also described the TDSIC Plan's estimated impact on retail revenues. She testified that NIPSCO's TDSIC Plan does not result in an average aggregate increase in NIPSCO's total retail revenues of more than two percent in a 12-month period.

Ms. Meece confirmed that, consistent with Electric Plan 1, NIPSCO will provide a schedule in each TDSIC tracker filing that identifies the projected effect of NIPSCO's Plan updates on retail rates and charges to determine the average aggregate increase percentage. If NIPSCO incurs TDSIC costs under the 2021-2026 Electric Plan that result in a revenue requirement that would exceed the percentage increase in a TDSIC approved by the Commission, NIPSCO will defer such costs as a regulatory asset for recovery as part of its next general rate case filed with the Commission. She noted that this methodology is the same as NIPSCO's currently approved methodology.

Additionally, Ms. Meece explained how NIPSCO's transmission and distribution rate base will grow annually through the 2021-2026 Electric Plan horizon because of its investment under the Plan.

Ms. Meece concluded with an explanation of how the proposed Plan is expected to impact NIPSCO's customers' bills. While the exact impact will be dependent on a number of different factors, assuming approval of the Plan, she said NIPSCO currently estimates TDSIC costs in the first TDSIC tracker filing after approval would result in a charge of approximately $2.65 to an average residential customer using 700 kWh per month, which is slightly higher than the $2.08 in TDSIC costs proposed in NIPSCO's TDSIC-8 tracker filing and the $2.61 in TDSIC costs under NIPSCO's currently-effective TDSIC-7 tracker.

5. <u>OUCC'S Case-in-Chief</u>.

A. <u>Anthony A. Alvarez</u>. Anthony A. Alvarez, Utility Analyst in the Electric Division, testified about NIPSCO's proposed AMI Project. He stated that the OUCC does not oppose AMI technology deployment. However, he claimed that NIPSCO had not provided a "best estimate of the cost" as required under the TDSIC Statute and that the costs associated with NIPSCO's AMI Project were not "justified by incremental benefits attributable" to the project and, ultimately, recommended the Commission deny including the AMI Project in NIPSCO's 2021-2026 Electric Plan.

Mr. Alvarez first explained NIPSCO's current AMR metering technology and noted that NIPSCO's original cost estimate for NIPSCO's AMR deployment was $28.8 million and that it was completed with a final installed cost of $29.95 million. He also summarized the proposed AMI Project and NIPSCO's estimated costs for capital and O&M.

Regarding the statutory requirement to provide a "best estimate," Mr. Alvarez testified that NIPSCO did not provide a "best estimate" as required by statute as that term has been defined by the Commission. Citing to the Commission's Order dated June 22, 2016, in NIPSCO Cause No. 44403 TDSIC-4, he took issue with the fact that NIPSCO did not provide any work order level detail cost estimate, or any detailed materials, labor and equipment cost estimates to support the AMI Project cost. He noted that Mr. Vamos provided an overall, total cost estimate for the AMI Project and pointed to Witnesses Kiergan and Holtz for additional support, and claimed that these witnesses offered no additional support for the AMI Project cost line items Mr. Vamos presented.

Mr. Alvarez stated that NIPSCO has yet to create the architecture or network designs for the AMI technology it plans to deploy and still needs to identify the specific meter, equipment, hardware, and systems including the headend, communication and meter data management systems it needs to build and serve as the AMI infrastructure's backbone. Also, the high-level capital and O&M expense estimates shown in Attachment 3-B did not include any detailed cost breakdown of the AMI Project. Based on NIPSCO's case-in-chief and responses to discovery questions, he claimed NIPSCO will not be able to provide a "best estimate" for the cost of the project until it develops, issues and evaluates its RFPs for the various AMI Project components, which would be during the second year of the deployment (2024). Mr. Alvarez also disagreed with Mr. Kiergan's testimony that stated NIPSCO's AMI Project is an AACE Class 4 estimate. Without the information Mr. Alvarez called out above, he stated NIPSCO's AMI Project "is still at its initial stages" and "has a very high degree of uncertainty." He further testified that "the project has a high possibility of future cost escalations with magnitudes of several factors."

Mr. Alvarez also provided a table comparing NIPSCO's AMI Project cost estimate to Indiana Michigan Power Company's ("I&M") proposed AMI deployment in Cause No. 45576 and Duke Energy Indiana, LLC's ("DEI") completed AMI deployment in Cause No. 44526. He stated NIPSCO's cost estimate is already significantly higher than the overall budget of I&M, who has a similar number of AMI meter installations.

Mr. Alvarez also provided testimony about the CBA included in NIPSCO's case-in-chief and sponsored by Witness Kiergan. He noted that Witness Becker stated that AMI has the potential to allow NIPSCO to integrate EVs and EV charging but criticized NIPSCO's CBA because it did not calculate or include the benefits or operational savings from AMI and EV charging. He acknowledged that NIPSCO stated it has taken a "conservative approach" in developing the CBA, but also noted Witness Kiergan himself identified EV as among the drivers for utilities to install

AMI. Mr. Alvarez testified that NIPSCO's conservative approach in developing the AMI CBA and excluding benefits from the baseline cost-benefit comparison made it very difficult to discern which benefits could add support to the viability of AMI and be attainable upon deployment, and which ones were simply aspirational and may take many years to materialize, if ever. He said this adds to the uncertainty of the project, since neither the costs nor the benefits were included.

Regarding the benefits identified in the CBA, Mr. Alvarez testified NIPSCO's AMI CBA shows the benefits from AMI deployment will not breakeven until 13.5 years (2033) after the project starts. He further noted that the end of the AMI deployment period in 2026, NIPSCO estimates the project will be at a net cost of $165.15 million; however, he also noted NIPSCO forecasts net annual benefits of $21.82 million over the next 10 years, resulting in a net benefit of $53.05 million in 2036.

Mr. Alvarez testified that the results of NIPSCO's AMI CBA are "quite concerning considering the 'conservative approach' NIPSCO claims it took and despite the 'considerable' number of AMI benefits it included into its business case over an extended 15-year study period to support the probable viability of its proposed AMI Project." He noted that NIPSCO did not include the benefits and operational savings associated with EV or EV charging and NIPSCO's business case did not consider ratepayers' loss of opportunity to finally receive the benefits from NIPSCO's initial investment of $30 million in AMR. On the other hand, he said NIPSCO will realize immediate returns of its AMI deployment investments through the TDSIC tracker mechanism.

Mr. Alvarez concluded this portion of his testimony by stating that the incremental benefits in NIPSCO's business case neither justify the cost of the AMI Project nor support deploying AMI technology. He said the AMI CBA NIPSCO presented to support its proposed AMI deployment was inadequate in validating the actual ratepayer benefits and utility operational benefits that may be achieved in the deployment and the analysis NIPSCO presented in its case-in-chief to endorse the AMI Project was underwhelming compared to the expectations it generated for AMI deployment in its April 26, 2021, NIPSCO Electric TDSIC 2021-2026 Plan presentation. Thus, he asserted it is unreasonable to approve the AMI Project at this time based on the lack of supporting cost data and the cost benefit analysis in NIPSCO's business case.

Mr. Alvarez also briefly discussed Ind. Code § 8-1-2-0.5 and testified there is insufficient evidence for the Commission to conclude that the AMI Project request is protecting the affordability of utility services for NIPSCO customers as required by this statute.

B. Mr. Hunt. Sergio G. Hunt, Utility Analyst in the Electric Division, testified about and sponsored a statistical methodology utilized to evaluate the spending under NIPSCO's 2021-2026 Electric Plan on a unit of risk basis and proposed elimination of certain projects and the associated costs from NIPSCO's proposed Plan. He provided a summary of NIPSCO's proposed Plan and associated costs for Aging Infrastructure ($753,121,380), System Deliverability ($281,439,419), and Grid Modernization ($362,054,616) project categories. He stated that the Aging Infrastructure and System Deliverability investments NIPSCO estimated the incremental benefits to be a 16% reduction in total system risk. He stated that this means more than one billion dollars of the Plan's cost has a calculated incremental benefit providing a 16% reduction in risk.

For grid modernization, he noted this category was estimated to save customers $529 million over a 20-year period.

Next, Mr. Hunt explained how risk was calculated by NIPSCO, with the assistance of S&L, and NIPSCO's TDSIC Risk Model, which ranks each asset based on its total risk score. (The risk score is calculated with the formula: Risk = COF x LOF.) He further explained how the COF and LOF were calculated. He explained that NIPSCO took its electric system total risk profile and then compared a "Break-Fix" approach versus the Plan's approach to proactively replacing assets, and based on this, NIPSCO estimated a 16% risk reduction at the end of 2026 if the Plan is implemented. Mr. Hunt said the OUCC does not find using the Break-Fix method of calculating risk a beneficial exercise and does not find this approach for calculating risk reduction reasonable, because it contrasts the Plan against a scenario that would not occur and should be compared against NIPSCO's regular maintenance schedule. Thus, in his opinion, NIPSCO's risk score calculated for the Plan overstates the risk reduction.

Mr. Hunt then explained the analysis he performed and his proposed way of measuring or understanding the cost of incremental benefits by project. His analysis accepted all of NIPSCO's inputs and methodology of calculating the risk score. He calculated the difference in asset risk scores, using this difference as a proxy for the incremental benefit of replacing each asset; then he summed the incremental benefit of each asset by the associated Project ID, with the summation providing the incremental benefit to the risk score of each project; and, finally, he divided the cost of each project by the risk score difference associated with each project. He included two confidential figures as well. Figure 1 is a graphical representation of all projects, ranked from least to greatest cost by dollar per risk unit reduced, shown in graphical form. He then created Figure 2, which excluded the most expensive project. He proposed that an "Upper Limit" be set to eliminate outliers based upon their cost per unit of risk, and everything over this Upper Limit was considered an outlier that should be excluded from NIPSCO's 2021-2026 Electric Plan. In confidential Figure 4, Mr. Hunt graphed the same projects from Figures 1 and 2, while excluding those that were above the Upper Limit.

Mr. Hunt admitted that his analysis was an economic analysis to determine a point where project costs can be reasonably viewed to have exceeded their benefit for those that are risk ranked (considering that NIPSCO has not quantified benefits in dollar terms). He also acknowledged that some projects may have been selected by NIPSCO because they were convenient to replace along with assets having a higher priority. For example, in NIPSCO's response to OUCC's discovery request 4-001, NIPSCO demonstrated there are some cost savings when replacing multiple assets simultaneously within a substation. However, he testified that NIPSCO's desire to replace assets in an orderly or cost-effective manner does not absolve it of the statutory requirement to ensure that incremental benefits exceed incremental costs.

Mr. Hunt characterized the OUCC's concern as being with "the exponential increase in the cost of some risk ranked projects using NIPSCO's own risk quantifications." He said some incremental units of risk reduction are projected to cost upwards of $1,000,000 and, thus, the high cost of risk reduction for some projects being proposed should be cause for concern, as ratepayers are paying for significant costs with relatively little tangible objective benefit. He believed that removing "outlier projects with unreasonable costs per unit of risk reduction, as determined by statistical analysis, provides an objective, transparent, reasonable method to meet I.C. 8-1-39-10(b)(3)'s incremental benefits requirement." Ultimately, his analysis recommended eliminating approximately $120 million from the Plan associated with 12 projects. He supported his proposed reductions by arguing they make the Plan cost more reasonable while still providing ample benefit for NIPSCO customers.

C. Mr. Lantrip. Kaleb G. Lantrip, Utility Analyst in the Electric Division, testified about NIPSCO's proposed accounting and ratemaking treatment. Ultimately, he recommended the Commission require NIPSCO to use actual retirements, rather than a three-year historical average estimate, in calculating its adjustment to depreciation expense. He also recommended NIPSCO's request to receive regulatory asset treatment of AMI O&M expenses be denied, consistent with Witness Alvarez's AMI Project denial recommendation. However, in the event the Commission approves NIPSCO's proposed AMI Projects, he recommended deferral of the requested AMI O&M expenses regulatory asset, without carrying charges, until the planned AMI Projects begin deployment. Mr. Lantrip also testified that NIPSCO does not have any concerns with NIPSCO's proposed annual updates to its TDSIC Plan, while continuing to file for cost recovery on a bi-annual basis, as discussed in Witness Becker's direct and supplemental testimony.

Specific to NIPSCO's ratemaking proposals, Mr. Lantrip discussed how NIPSCO's TDSIC mechanism currently works, including recovery of 80% of costs through the TDSIC mechanism and deferral of 20% for future recovery, as well as NIPSCO's authority for CWIP ratemaking treatment and recovery of PISCC. He further explained how NIPSCO proposes to calculate its TDSIC revenue requirement.

Mr. Lantrip explained NIPSCO's proposal to calculate and recover depreciation and property tax expenses based on projects completed as of the TDSIC expenditure cut-off dates, which is intended to reduce regulatory lag that occurred in NIPSCO's Electric Plan 1. He stated the OUCC does not have any concerns with this proposal, as it is reasonably based on a fixed, known and measurable number of in-service investments as of the cut-off date and is consistent with a recent Commission order in Cause No. 45264.

Mr. Lantrip next testified about NIPSCO's proposal to adjust depreciation expense for retired or replaced assets, using a three-year historical average retirement rate derived from its FERC Form 1. He explained how this would work and noted that Witness Meece claimed the use of a three-year average addresses the difficulty of identifying the precise assets retired due to lag on recognizing within the recovery period when the retirement was made. Further, Ms. Meece also indicated NIPSCO may make adjustments to the historical information if needed to address extraordinary or unusual items that skew the calculation, but if such an adjustment is made, an explanation will be included in the supporting workpapers to be provided to all parties. Mr. Lantrip expressed concerns with this NIPSCO proposal and recommended that, instead of using a three-year historical average, NIPSCO use actual retirements. He explained that other Indiana electric utilities utilized historical, actual retirements, including CenterPoint Electric Indiana South in Cause No. 44910 and AES Indiana in Cause No. 45264 TDSIC-1. Therefore, he concluded "it should be possible for NIPSCO to update its accumulated depreciation in reconciliation for the assets being replaced, offsetting gross TDSIC plant additions, which would satisfy matching principles better within the TDSIC rider."

On the topic of O&M Expenses, Mr. Lantrip explained NIPSCO's request for regulatory asset treatment on the recovery of O&M expenses associated with its 2021-2026 Electric Plan AMI Project, which is estimated at $10.015 million. For this, he recommended NIPSCO's request for an AMI O&M expenses regulatory asset be denied, consistent with Mr. Alvarez's recommendation the AMI projects be denied. However, in the event the Commission approved the AMI Project and the associated O&M expenses, he recommended the regulatory asset treatment on the O&M expenses be granted as conditional upon a deferred amount without carrying charges until the AMI projects are deployed, as the customer benefits would begin as soon as the AMI project meter deployment begins in 2024.

6. <u>Industrial Group's Case-in-Chief</u>. Brian C. Collins, Principal, Brubaker & Associates, Inc., provided an overview of NIPSCO's proposed 2021-2026 Electric Plan, including the total direct and indirect capital cost estimates and project categories. He stated NIPSCO presented a "monetization" analysis only with respect to the Grid Modernization portion of the Plan (26% of planned spending), but did not put a dollar value on the alleged benefits for either the reliability-based Aging Infrastructure projects (54% of planned spending) or the System Deliverability projects (the remaining 20% of planned spending). He also pointed out that NIPSCO is proposing a significant increase in annual investment, as well as an overall investment, in the proposed Plan when compared to Electric Plan 1. Looking at the total (direct and indirect) investment of $1.625 billion over 5 years and 7 months, he noted the average annual spend under the new TDSIC Plan would be approximately $290 million, which is a 70% increase over the average annual spending.

Mr. Collins noted that with the proposed additions to NIPSCO's transmission and distribution ("T&D") system, NIPSCO's T&D rate base is projected to increase from $1.2 billion in 2016 to $4.2 billion by 2026. This dramatic increase in rate base will have a significant impact on customer rates, and NIPSCO projected that by the final year of the Plan, NIPSCO will collect over $101 million annually through the TDSIC tracker. Accordingly, the expected rate impact is an important factor in evaluating the cost-benefit balance NIPSCO's proposal would have compared to whether the proposed spending will actually provide risk reduction and reliability benefits that justify the massive investment.

Mr. Collins noted that Witness Vamos stated one of the primary goals of the new TDSIC Plan is to reduce the overall system risk associated with aging asset populations and asset failures and that NIPSCO estimated a 16% risk reduction associated with the Plan. Taking into consideration that Electric Plan 1 already reduced risk by 21%, Mr. Collins stated that NIPSCO's estimated 16% risk reduction would actually be only 12.64% risk reduction if a 2016 baseline were utilized. He also testified regarding his concerns about NIPSCO's utilization of a fictional "break/fix" approach for purposes of calculating risk reduction. He noted that NIPSCO acknowledged it does not utilize a "break/fix" approach, but engages in proactive and preventative maintenance practices as demonstrated through NIPSCO's past three rate cases. He stated that NIPSCO's estimated risk reduction was "significantly exaggerated" and testified that NIPSCO artificially inflated the impact of TDSIC work.

Mr. Collins also discussed certain reliability indices, such as System Average Interruption Duration Index ("SAIDI"), Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI"). He stated that during Electric Plan 1 (2016-2020), the reliability metrics do not substantiate the theory that NIPSCO's TDSIC investments have increased measured reliability. He testified that these three indices are trending upward, not improving. He also testified that NIPSCO did not provide any projected reliability metrics associated with the 2021-2026 Electric Plan.

He stated that NIPSCO has provided no evidence to support an increased level of TDSIC spending in light of the diminishing customer benefits. Considering no identified need to intensify T&D buildout, plus the artificially inflated risk reduction computation put forth by NIPSCO, the proposed TDSIC Plan is not reasonable where the spending is greatly increased and the impact on service quality is going down.

Mr. Collins noted that NIPSCO's risk reduction rationale discussed above pertains specifically to the Aging Infrastructure portion of the Plan, and the System Deliverability portion is driven predominantly by load growth and increasing demand. However, he criticized NIPSCO for not proposing any kind of offset for the incremental rate revenue associated with increased sales due to load growth. He stated that NIPSCO is seeking TDSIC funding to require ratepayers to cover all of the costs, while retaining all the incremental revenue benefits from increased sales between rate cases. He testified that NIPSCO provides such a credit mechanism in its gas TDSIC Plan for investments in rural extensions. He testified that if a credit mechanism for the electric TDSIC Plan is not feasible, the Commission should consider the added sales revenues from load growth when determining an appropriate pretax return for NIPSCO's rate recovery under the TDSIC Statute.

Similarly, with respect to the AMI Project, Mr. Collins explained that NIPSCO's AMI investments are anticipated to produce cost savings, such as reduced O&M, which are currently recovered in NIPSCO's base rates. He again criticized NIPSCO for not including an offset to the TDSIC mechanism to account for such savings and stated the Commission should consider that factor when determining an appropriate pretax return for NIPSCO's rate recovery under the TDSIC Statute.

Mr. Collins also testified about NIPSCO's Economic Impact Report. He testified that the report treats the proposed TDSIC investment as a form of stimulus spending and criticized it for not accounting for the economic detriment this level of investment could have through increased electric rates. He noted that the report was not a cost-benefit analysis and said it does not measure net economic impact because it examines only the asserted benefits of utility spending in the United States and abroad, without any effort to account for the economic detriment of rate increases paid by NIPSCO's captive customers. Mr. Collins said the purpose of the TDSIC Statute is not to promote stimulus spending by utilities, for the benefit of vendors and contractors. Instead, the purpose is to facilitate prudent system investment, but only to the extent that the resulting rate burden is justified by improvements in the reliability, efficiency, or safety of the service being rendered to the ratepaying public.

Mr. Collins discussed the settlement agreement related to Electric Plan 1, noting that

NIPSCO terminated the settlement agreement as of May 31, 2021. He noted that this settlement agreement had annual and overall caps on NIPSCO's level of investment that would have extended through 2022. He explained that NIPSCO's termination of the Electric Plan 1 meant that NIPSCO is no longer bound by those terms, allowing NIPSCO to propose its current Plan with a huge increase in annual spending starting in mid-2021. According to Mr. Collins, the Commission should scrutinize the increasing spending under the new plan in light of the cost caps previously agreed upon that are no longer in place.

Mr. Collins testified about the level of contingency included in NIPSCO's cost estimated under the Plan. He noted that estimates for the first 2 years of the TDSIC Plan projects are based on Class 3, Class 4, and Class 5 cost estimates and years 3-6 project estimates included in the Plan are based on Class 5 estimates, which only have a defined project scope up to 2%, with variability in cost as much as an additional 50%. Mr. Collins testified that the project cost for years 3 through 6 are approximately $1.24 billion, or approximately 76% of the total Plan cost, and if the variability in cost increased by 50%, plan expenditures would increase by 38%, or an additional $620 million beyond the proposed $1.625 billion spend.

Mr. Collins recommended NIPSCO's proposed contingencies be disallowed altogether. He stated that, given the enormous uncertain cost estimates in the new TDSIC Plan, any cost overrun should be borne by NIPSCO and not assigned to ratepayers. He stated providing NIPSCO with an extra layer of cushion preapproved for recovery in rates is unnecessary and inappropriate. Mr. Collins testified that under Section 9(g) of the TDSIC Statute, if NIPSCO encounters unanticipated issues in the course of implementing its Plan, it can seek recovery of excess costs by providing specific justification and securing specific Commission approval. He stated that this Section 9 process adequately addresses the concern that unforeseeable contingencies could impact NIPSCO's ability to complete the planned work within the approved budget and does so with a more balanced and reasonable allocation of risk than the contingency allowance proposed by NIPSCO.

Mr. Collins stated that NIPSCO is proposing a depreciation netting mechanism applicable to asset replacements. He noted that for projects that involve replacement of existing system assets, the TDSIC mechanism provides for recovery of incremental costs associated with the new asset, including depreciation expense, pretax return, O&M, taxes, and carrying costs. However, he stated that return associated with removed assets that are being replaced is also embedded in NIPSCO's base rates and that NIPSCO's proposal addresses only the "return of" (depreciation) component embedded in base rates, but not the "return on" (margin) component. In effect, he stated that NIPSCO would receive duplicative recovery for successive assets performing the same functions in the same locations – once through return embedded in base rates for replaced assets and again through added return under the TDSIC mechanism for the replacement assets. He stated that his understanding was that a 2015 appellate decision considered the question and found that the TDSIC Statute did not require netting for return associated with replaced assets, but noted that the Commission could take that consideration into account when determining the appropriate pretax return to allow on TDSIC investments. Therefore, he recommended that, if the Commission concludes that it does not have authority to require a full netting in the context of asset replacements, then that warrants a downward adjustment to the pretax return approved for TDSIC investments under NIPSCO's 2021-2026 Electric Plan.

Mr. Collins stated that he is not opposed to NIPSCO investing in its electric system to continue to provide reliable service to customers. However, he said the Commission must ensure that NIPSCO's investment is prudent and cost-justified in light of the incremental benefits that ratepayers can reasonably expect to derive. He further explained that it is critical that the Commission exercise its regulatory authority to ensure that there is a fair and reasonable balance between the costs imposed on ratepayers and the incremental benefits to the service they receive. He stated that because NIPSCO failed to demonstrate that its excessive spending proposal achieves anything more than minimal, if any incremental benefits in risk reduction or reliability, the Commission should deny NIPSCO's proposal due to lack of sufficient support showing the incremental benefits justify the estimated costs. NIPSCO would then have the opportunity to present a revised plan for Commission review, with a more reasonable balance between the costs imposed on ratepayers and the service benefits they receive, such as pacing the expenditures over a longer time period.

7. NIPSCO's Rebuttal.

A. Ms. Becker. Ms. Becker began her rebuttal testimony by explaining there were several issues that are raised by the OUCC and Industrial Group that have recently been addressed by the Commission in TDSIC proceedings. Examples of such issues that she cited to include (1) inclusion of contingency as part of NIPSCO's cost estimates, which is challenged by Mr. Collins; (2) Mr. Collins' argument that NIPSCO should be required to go beyond the proposed depreciation offset/netting to address alleged "duplicative recovery" and wanting to reduce NIPSCO's approved return on equity ("ROE"); (3) utilization of a "break/fix" analysis as a valid baseline for comparison of the risk reduction benefits of certain projects, raised by Mr. Collins; and (4) Mr. Lantrip advocating for NIPSCO to be required to use actual retirements, instead of three-year historical average, for its depreciation offsetting methodology. She testified that in none of these instances did a witness point to distinguishing facts or differences that would lead to a different conclusion, nor did they generally even acknowledge they are asking for things the Commission has very recently rejected or that are the opposite of what the Commission has recently approved.

Ms. Becker testified that NIPSCO should not be required to relitigate literally the same issues each time a TDSIC Plan is filed. Instead, if the Commission has definitively spoken and if relevant statutory language has not changed and no party has identified any materially different facts or factors, the Commission's prior pronouncements and findings on each of these issues should be re-affirmed. While NIPSCO understands that each Cause before the Commission is an independent proceeding which will be evaluated on its own merits, when parties continue to raise arguments that have been rejected by the Commission, it forces NIPSCO to address such issues, which is not an efficient use of resources.

Ms. Becker also expressed concern with how Witness Alvarez painted NIPSCO's proposed AMI Project in the most unfavorable light possible and used this inaccurate and unfair portrait to support his request to deny approval—or at least to deny approval at this time. She claimed he did not provide proper context, overstated costs, and made incorrect statements in order to support his pre-determined position. She stated that when looking at the evidence in this case, in the proper context and without making invalid negative inferences, it is clear NIPSCO has put forth a well-supported AMI Project that should be approved. Similarly, Ms. Becker said that Mr. Collins overstated or distorted the facts in this proceeding. For example, he said NIPSCO "refused" to provide responses to the Industrial Group's discovery requests, when the Company did not have the data/analysis requested. He also claimed NIPSCO is using inflated risk reductions numbers but undeniably and intentionally uses incorrect and significantly higher "total costs" for all projects as his basis for comparison when he acknowledged that only Aging Infrastructure projects are aimed at risk reduction.

Ms. Becker summarized Mr. Collins' criticisms of NIPSCO's Plan, which are discussed above. She responded by noting that NIPSCO has been transparent about the importance and size of its planned investments under the Plan, both in its stakeholder meeting before making its filing and in its case-in-chief. She also explained that there were more than \$526 million of projects included in the 2021-2026 Electric Plan that were previously approved by the Commission as part of Electric Plan 1. Additionally, she said more than \$322 million in investments associated with Grid Modernization were proposed based on the General Assembly's expansion of the scope of the TDSIC Statute, and approximately \$92 million related to Wood Poles and Circuit Performance projects were similarly being included based on statutory revisions. She included these figures to provide context and demonstrate that about \$618 million in projects were previously part of an approved TDSIC Plan, and another \$322 million relates exclusively to new project categories as explicitly authorized under the revisions to the TDSIC Statute—accounting for nearly \$950 million of NIPSCO's total of \$1.6 billion in proposed investments.

Ms. Becker next recounted Mr. Alvarez's general conclusions about the AMI Project. While noting Witness Kiergan provided a more direct response, she explained that NIPSCO has thoroughly addressed his concerns in its case-in-chief. For example, NIPSCO had explained why it needs to invest in AMI in order to be a modern utility, and needs to begin the project at this time, as it will require multiple years to execute and presented a CBA that shows more benefits than costs, which is important. With respect to add-on programs enabled by AMI, she testified that the Commission and various stakeholders have been asking NIPSCO for additional information about and opportunities for customers on a variety of issues including DERs, EVs, demand response programs, load forecasting, and time of use rates—all of which are virtually impossible to implement without AMI technology. She specifically called out the 2019 update to the TDSIC Statute, which allows for investments in "advanced technology" (IC 8-1-39-3 (b) (2)) demonstrating support for such projects in TDSIC plans.

Ms. Becker stated that Mr. Alvarez implied, if the AMI Project is approved, NIPSCO would be getting a "blank check" and the Company could spend as much money as it wants, without any constraints, and have guaranteed cost recovery. She testified that Mr. Alvarez had, without citing to any evidence in support, specifically claimed that "the [AMI] project has a high possibility of future cost escalations with magnitudes of several factors." He had also ignored, to the extent approved costs were to increase, NIPSCO would have to specifically justify cost increases and receive an additional approval for the cost increases before getting to recover them in the TDSIC tracker.

Ms. Becker responded to these criticisms by reiterating that NIPSCO has continued to follow AACE methodology for developing cost estimates, a practice repeatedly approved by the Commission, not just for NIPSCO, but for other utilities as well. Although Mr. Alvarez complained about the AMI project estimates, she noted that he did not claim NIPSCO deviated from its process of utilizing AACE estimating methodology and completely ignored that NIPSCO has used the same process effectively for years for other project types. She further explained that it should be expected that some estimates that are part of a 5-7 year TDSIC plan will be Class 4 or 5 estimates, as projects in the latter part of a plan will not be as defined as earlier-year projects.

Ms. Becker also pointed out that, unlike Mr. Lantrip, Mr. Alvarez ignored the Section 10 Plan filing and the Section 9 tracker/update process, where cost estimates can be refined and updated. She expressed disappointment at this "given the great rapport NIPSCO and the OUCC have developed involving on-going review of project updates through the TDSIC tracker process under Section 9"—which includes a stakeholder meeting approximately four weeks before the filing, a pre-meeting to review testimony with explanations for specific project increases, an audit package which includes the information the OUCC routinely needs to complete its review, and post-filing meetings to discuss follow-up questions or concerns. She then explained the Section 9 "plan update" process that NIPSCO would follow in the event of any proposed cost increases for approved TDSIC projects.

In response to Mr. Collins' recommendation that all contingency be disallowed, Ms. Becker responded by pointing out that Mr. Collins himself offered similar testimony in Cause No. 45264. There, the Commission explicitly rejected his arguments and was very definitive that exclusion of contingency in estimates would actually mean estimates are not "best estimates" as required by the TDSIC Statute. She cited to page 23 of the Commission's final order in that proceeding, where the Commission unequivocally found: "we find the exclusion of contingency from the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute." Likewise, further on page 23 of the Commission's July 22, 2020 order in Cause No. 45330, the Commission approved NIPSCO's estimation methodology, which included contingency, over this same objection by the Industrial Group for NIPSCO's gas TDSIC Plan. She reiterated that NIPSCO has followed the same AACE estimation methodology (and no party has alleged the Company has not). This has been approved as recently as the 45330 Order, over this exact objection from the Industrial Group. Quite simply, the Commission has recognized time and time again that contingency is not just an allowable, but a required, component of a "best estimate."

Ms. Becker briefly repeated Mr. Lantrip's concerns on this topic. She then responded by testifying that NIPSCO is proposing an identical methodology to that approved by the Commission in NIPSCO's most recent gas TDSIC case—which was a gas case. She criticized Mr. Lantrip for not even acknowledging this order, let alone discussing its findings, despite NIPSCO citing to and relying upon it. In addition to the difficulty of "matching up" exact deployed and retired assets, as described in Ms. Meece's direct testimony, Ms. Becker explained that there is often a significant lag between when a new asset is included in rates for recovery and when retired assets are actually "retired" on NIPSCO's books for accounting purposes. This is potentially problematic because it would be extremely challenging to determine the "actuals" like Mr. Lantrip would prefer and likely resulting in the "actuals" NIPSCO would be required to use for any filing being only estimates, thereby need to be subject to reconciliation at a later time. Furthermore, she testified that if

NIPSCO were required to implement a different netting process for its electric TDSIC tracker than has been approved for its gas TDSIC tracker, this would lead to inefficiencies, which can be avoided by utilizing the same netting process as NIPSCO has requested. For all these reasons, she said the Commission should approve NIPSCO's proposed depreciation offset (or netting) methodology.

Ms. Becker also explained Mr. Collins' challenges to NIPSCO's depreciation offsetting proposal. She testified that NIPSCO, after concerns expressed by both the OUCC and Industrial Group, offered a solution in Cause No. 45330-TDSIC-1 that was approved by the Commission in its December 23, 2020 order in that cause. Citing page 19 of that order, she testified that this exact same claim of double or duplicative recovery was rejected by the Commission in that order. Thus, she said the Commission should not require more from NIPSCO here absent compelling reasons, which do not exist.

Regarding Mr. Collins' argument that NIPSCO should be required to provide an offset for the incremental rate revenue associated with System Deliverability projects, Ms. Becker responded with two points. First, she stated there is nothing in the TDSIC Statute that requires such an offset, and, in fact, through the TED portion of the statute, the General Assembly goes as far as encouraging utilities to include projects that increase load, without an offset for incremental revenue, for projects that encourage economic development. Additionally, she said that neither NIPSCO nor any other utility has been required to create such an offset in any plan previously approved by the Commission. Second, she said it was important to note that NIPSCO is required to file an electric base rate case before the expiration of its TDSIC Plan. Therefore, to the extent the Commission shares the concern raised by Mr. Collins that NIPSCO will receive some undefined level of "incremental revenue," she testified this would be only for a short duration following project execution and would be recognized in the required base rate case.

Ms. Becker testified that NIPSCO is not certain of exactly what Mr. Lantrip's proposal is, but NIPSCO believes that Mr. Lantrip is recommending that NIPSCO not be allowed to accrue carrying charges only for the period between NIPSCO's expenditure of capital investment and the date of deployment of the AMI Project, but that NIPSCO would be allowed to accrue carrying charges for the period after the date of deployment of the AMI Project and until associated costs are fully recovered from NIPSCO's customers. Therefore, she said it appears that Mr. Lantrip argues that NIPSCO should be able to defer any O&M expenses related to AMI for collection, without carrying costs, until 2024.

Ms. Becker responded by noting that Mr. Lantrip had cited to no Commission precedent in support of this proposal, and that NIPSCO is unaware of any Commission support. However, she explained that in every applicable TDSIC order NIPSCO is aware of with O&M, carrying charges were allowed on all deferred amounts beginning when they are recognized in the TDSIC tracker—not deployment or in-service, including multi-year projects, such as O&M for the System Integrity Data Integration Project that was approved by the Commission in Cause No. 44403.

In response to Mr. Collins' discussion of the Settlement Agreement in Cause No. 44733, Ms. Becker testified that it was approved by the Commission and terminated by NIPSCO effective May 31, 2021, when it terminated its TDSIC Plan under the agreement. She said that this prior

Settlement Agreement is not relevant to the proposed 2021-2026 Electric Plan that is before the Commission for two reasons. First, NIPSCO complied with the terms of that Settlement Agreement, and no party has claimed otherwise. For example, NIPSCO has abided by agreed-to annual and overall cost caps and other settlement terms. Second, that Settlement Agreement explicitly allowed NIPSCO to file a new Plan and also explicitly provided that, in the event of terminating the prior Plan and approval of a new Plan, the agreed-to cost caps would be terminated. She noted that no term of the Settlement Agreement provides that NIPSCO's new filing should be "more closely scrutinized," and Mr. Collins provided no support for his claim—beyond his personal opinion. Therefore, she testified the standard to which NIPSCO should be held is simple. It should be held to the standards and requirements of the TDSIC Statute, as it has been interpreted and applied by the Commission, and nothing more. It would be improper and unfair to hold NIPSCO to any different or higher standard or level of scrutiny simply because it previously entered and properly terminated the Settlement Agreement.

B. <u>Mr. Vamos</u>. Mr. Vamos began his rebuttal testimony by noting Mr. Collins' testimony about the level of annual and overall spending under the 2021-2026 Electric Plan and acknowledging that it is accurate to say that NIPSCO has been investing in and proposes to increase its investment in T&D under its TDSIC Plan. However, he disagreed with some of the characterizations and assumptions contained in Mr. Collins' testimony. Mr. Vamos provided some statistics from the Edison Electric Institute that showed significant and increasing investment levels by investor-owned electric companies since 2015. He provided these statistics to demonstrate that, while NIPSCO has increased its level of transmission and distribution investment over the last several years, which Mr. Collins points out, NIPSCO is not an outlier in the industry and that the changes and challenges NIPSCO and the broader industry are facing today and preparing for tomorrow require significant investment of capital, such as the investments NIPSCO is proposing under its 2021-2026 Electric Plan.

Mr. Vamos also responded to some of the characterizations and assumptions contained in Mr. Collins' testimony. He said Mr. Collins is not engaging in an apples-to-apples comparison; thus, the foundation on which he bases his claims is faulty. For example, he ignores the fact that a significant portion of the proposed TDSIC Plan is "carryover" projects from the prior TDSIC Plan that were approved utilizing the same methodology as this proposed Plan. Likewise, while he does state what percentage of the TDSIC Plan relates to Aging Infrastructure, System Deliverability, and Grid Modernization, he generally ignores the fact that the Grid Modernization category is a new category allowed under a fairly recent amendment to the TDSIC Statute, which NIPSCO has chosen to utilize—which naturally increases NIPSCO's total planned investment.

With respect to Mr. Collins' claim that the Plan involves "clearly diminishing benefits" for NIPSCO's customers, Mr. Vamos first noted that the evaluation the Commission must undertake under Section 10 of the TDSIC Statute is "whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan." Thus, the benefits associated with NIPSCO's prior Plan are not relevant to that determination, and this Plan should be evaluated on its own merits. Second, he stated that NIPSCO has acknowledged that one type of benefit measure is estimated to be less than what was originally estimated and ultimately realized under NIPSCO's original Plan, but that does not mean that the overall "incremental benefits attributable to the plan" are "clearly diminishing." He cited the 16% estimated risk reduction under this Plan and reiterated points from his direct testimony that explained this difference, including (1) the initial assets addressed in Electric Plan 1 were of higher impact, because they were the highest risk assets of the whole NIPSCO asset population and (2) NIPSCO will be replacing all aging assets at the same location (including some that are not as high of risk as the those NIPSCO is specifically targeting). He also noted that this risk reduction benefit is only one aspect of the Plan's benefits.

Regarding Mr. Collins' discussion of certain reliability metrics, Mr. Vamos said that it was interesting that Mr. Collins noted that certain of NIPSCO's metrics (such as SAIDI, SAIFI, and CAIDI) have not recently improved and then argues the 2021-2026 Electric Plan not be approved, when a majority of the proposed Plan is to replace Aging Infrastructure and better serve NIPSCO's customers. He responded by noting that Mr. Collins ignored the fact that, had NIPSCO not executed its prior Plan, its metrics likely would have declined, rather than held steady. Second, Mr. Vamos pointed out that Mr. Collins had ignored the reality that if NIPSCO stops spending (or had not spent in the past), reliability metrics would very likely not be where they are today. He also pointed to another factor to be considered, which is wholly ignored by Mr. Collins, which is the impact on NIPSCO's reliability metrics during the execution of the TDSIC projects. He explained that over the course of past five years, NIPSCO has experienced higher impact outages due to the fact that much of its system needed to be tied together into order to execute the work under the prior Plan. Finally, he also said another important consideration is how little of the system was touched during NIPSCO's last TDSIC plan. Less than 8% of its assets were impacted by these investments. Mr. Vamos confirmed that NIPSCO is always striving to improve reliability generally and the metrics like SAIDI, SAIFI, and CAIDI, specifically. He also acknowledged that NIPSCO has room to improve and said this TDSIC Plan is a very important part of NIPSCO's work to do that.

Mr. Vamos also testified about the incremental benefits attributable to NIPSCO's Plan. He said the Plan addresses safety, reliability, grid modernization, and allows for future economic development, all providing incremental benefits for NIPSCO's customers. He noted that pages 23-27 of his direct testimony highlighted risk reduction, which is one key benefit, especially as related to NIPSCO's Aging Infrastructure category projects and that he spent significant time in his direct testimony explaining the overall incremental benefit associated with the 2021-2026 Electric Plan. These benefits are substantial and do not fall into one category. He cited to benefits such as (1) maintaining and improving upon NIPSCO's safety practices; (2) providing the means to better protect NIPSCO's customers and employees through investments, such as increased system visibility and faster acting protective devices; and (3) addressing NIPSCO's continually-aging system. Without proactive replacement of many of these assets, he explained NIPSCO's system would be more susceptible to larger and more frequent interruptions due to asset failures. For Deliverability projects, he noted these were chosen to meet the increasing demands of NIPSCO's customers and that not performing this kind of proactive work would prohibit NIPSCO from fulfilling its obligation to serve its customers, which is simply not an option.

Mr. Vamos continued by addressing benefits that had been monetized and those that had not been, in response to Mr. Collins. He testified that, while NIPSCO has not calculated monetized benefits associated with every project category, there are undeniably benefits associated with each project category both in risk reduction and the ability to meet customer deliverability needs. He cited to pages 25-26 of his direct testimony, where NIPSCO's position on this was outlined in great detail. Additionally, he pointed out that NIPSCO did offer a CBA associated specifically with its AMI Project, and NIPSCO also provided similar analysis for its Distribution Automation Project in Confidential Attachment 2-E to his direct testimony. Further, NIPSCO also put forward a report about the economic impacts expected to flow from NIPSCO's investment under the Plan. Thus, he concluded NIPSCO had fully justified the Plan in terms of overall benefits versus overall costs.

Mr. Vamos admitted that Mr. Hunt and Mr. Collins were partially correct in their criticisms on this point. He acknowledged that NIPSCO does not utilize a "break/fix" approach for its maintenance practices, but utilizes a proactive maintenance program and said NIPSCO has never represented otherwise. However, he responded that this does not mean that the break/fix approach that was utilized for a baseline from which to compare the replacements planned under the 2021-2026 Electric Plan is not appropriate. He quoted NIPSCO's response to Industrials Request 3-006, attached to Mr. Collins' testimony at Attachment BCC-2, p. 1, which said "[t]he 'break/fix approach' is a holistic representation of no proactive replacements of aged and/or deteriorated assets and is typical for use as a baseline comparison when evaluating risk reduction." He explained that what NIPSCO is comparing is specifically the work proposed under the TDSIC Plan versus not doing any of the work in the Plan and this theoretical assumption was used to portray the benefit of the Plan and not represent the current operating practices at NIPSCO.

Mr. Vamos further discussed a Commission order on this topic. He noted on page 10 of the Commission's March 4, 2020 order in Cause No. 45264, where the Commission evaluated and ultimately approved an electric TDSIC plan proposed by Indianapolis Power and Light ("IPL") (now AES Indiana), the Commission recited a very similar challenge to IPL's estimated risk reduction which was actually offered by Mr. Collins in that proceeding as well. The Commission did not accept the challenges or criticisms raised by Mr. Collins and found on page 24 that "record evidence demonstrates that the IPL Plan is proposed to reduce risk of asset failure and maintain service reliability. In doing so, the TDSIC Plan provides incremental benefits compared to how the future would otherwise unfold." He said that the Commission accepted IPL's methodology, and there is no reason for the Commission to reverse course in this proceeding. Furthermore, he noted that NIPSCO utilized this same risk assessment methodology in Cause No. 44733 to support its prior electric TDSIC Plan. While Cause No. 44733 resulted in a settlement agreement and the risk reduction analysis presented by NIPSCO was not explicitly challenged, he said this was another example, at minimum, illustrates this is a typical and valid form of comparison.

Mr. Vamos also responded to the direct testimony of Witness Hunt. He noted that Mr. Hunt does not claim that any proposed projects are not eligible under the TDSIC Statute, nor does he take issue with NIPSCO's 2021-2026 Electric Plan or its T&D Risk Model. Instead, he applies a "new source of risk analysis" and argues for the exclusion of several projects and a significant amount of overall capital investment. After briefly explaining NIPSCO's TDSIC Risk Model and project selection process, Mr. Vamos directly responded to Mr. Hunt's analysis, saying Mr. Hunt applied an arbitrary risk reduction threshold and does not justify the dollar level at which it is set. Additionally, he said Mr. Hunt's analysis is performed entirely in a vacuum that does not involve any real-world, human input by those who are familiar with the projects and completely ignores the reality of how NIPSCO's electric system actually operates. He explained the human input and real-world evaluation NIPSCO undertook in project selection was an important component from the perspective of considering the importance of a project to NIPSCO's overall system, and ultimately determining if it should be included or excluded from the proposed Plan. Mr. Vamos continued by noting that while Mr. Hunt acknowledges that not all projects proposed by NIPSCO are risk-based and have no "risk ranking," he still applied his analysis to such projects, such as the Deliverability category of projects. Finally, he said the strict application or Mr. Hunt's analysis would lead to unrealistic and problematic outcomes, which raises substantial questions about its usefulness even as a single point of reference.

Mr. Vamos then further outlined some of NIPSCO's specific concerns with Mr. Hunt's analysis. First, he stated that strict adherence to Mr. Hunt's analysis would lead to arbitrary removal of projects, many of which would be problematic to NIPSCO's 2021-2026 Electric Plan and overall electric system reliability. Second, he pointed out that five of the projects Mr. Hunt proposes to eliminate are "carryover" projects from NIPSCO's prior Plan, meaning they have already been found to be eligible TDSIC projects by the Commission, yet he does not even acknowledge—let alone explain—why previously-approved projects should now be excluded. He acknowledged that some projects cost more "per unit of risk reduction," but noted this is to be expected due to the difference in project types. For example, not all projects are an "in kind" replacement, and some projects cost more than others to perform due to the differences in construction needed to complete the project.

Mr. Vamos noted that the projects Mr. Hunt proposed to eliminate fall into both the Aging Infrastructure and Deliverability categories, proposing the removal of eight System Deliverability projects and four Aging Infrastructure projects totaling approximately $120 million dollars. He pointed out that the System Deliverability projects were not selected primarily for risk reduction, but for accommodating system upgrades for areas of growth and high stress. Therefore, the argument that these projects do not deliver enough "risk reduction per dollar spent" is not an appropriate basis on which to judge them.

Mr. Vamos testified about NIPSCO's new Marktown Substation deliverability project (project TSNRS19). He stated that the Marktown substation is one of the most important substations in NIPSCO's entire system. For example, it provides electricity to several large industrial facilities along the Lake Michigan shoreline, including the BP Whiting Refinery, which is the largest refinery in the Midwest and makes enormous contributions to the region's transportation network. He explained that the investments planned at this substation will require constructing an entirely new 138kV substation, including 138kV transmission line relocations. Because the Marktown substation was constructed over 90 years ago and the average asset age is 37 years old, NIPSCO has planned work to address significant challenges that exist with the aging, antiquated assets, such as difficulty in obtaining clearances, the inability to take certain assets out of service, the lack of redundancy, and the absence of modern breaker schemes and relaying capabilities. He noted this project is significantly more complex than a typical "in-kind" breaker or transformer replacement and will cost significantly more to complete. While acknowledging the relatively high cost is likely why it was proposed for elimination by Mr. Hunt's analysis, he called out that there is no discussion or even recognition of the importance of the Marktown Substation project in his testimony or attachments. Rather, he simply proposed to exclude it based on an arbitrary threshold.

Mr. Vamos testified Mr. Hunt's analysis also did not take into account the criticality of other assets. As an example, the list of assets by project that were proposed for removal includes "Asset DS001007" from project DSTU43, which is a 69-12kV 14 MVA transformer. While some assets project to have the same risk reduction, he explained that a transformer will have significantly higher costs than equipment like breakers or transmission poles. Despite the higher cost, Mr. Vamos testified a transformer is one of the most critical pieces of equipment in the power system. However, because of their relatively higher cost, Mr. Vamos claimed there is almost a "bias" against these important-but-expensive type of asset replacements in Mr. Hunt's model.

For all these reasons, Mr. Vamos concluded it would not be appropriate for the Commission to apply Mr. Hunt's new analysis and utilize it as a basis for excluding valid, eligible TDSIC projects from NIPSCO's 2021-2026 Electric Plan.

C. <u>Mr. Kiergan</u>. Mr. Kiergan submitted rebuttal testimony for NIPSCO in response to Mr. Alvarez and his criticisms of the AMI Project. He definitively stated that the comprehensive NIPSCO Electric AMI CBA is a "best estimate" for the costs of the AMI Project. In preparing the cost estimate that was submitted in NIPSCO's case-in-chief, he explained that West Monroe utilized its many years of experience in developing AMI business cases and extensive, detailed benchmarking, of both modeled costs and actual costs for AMI programs, to develop the costs in the CBA. Also, he explained West Monroe's unit cost benchmark data is based on 10-15 recent electric AMI programs and is continuously refined and updated as new CBAs are developed and costs for specific components change.

Mr. Kiergan also testified in detail about how the cost estimate for the AMI Project was developed. He explained that costs were not modeled in a top-down approach, where one would use an overall program per meter cost or component-level top-line costs; instead, costs in the CBA were built from the bottom-up using a combination of benchmarked and NIPSCO-specific per-unit costs. He noted numerous categories and components where this was the case. In other areas, such as IT, he explained that work order level detail was used to develop cost estimates. That is, IT costs were not estimated at an overall program level but were built up based on individual components, or work orders, and specific cost categories within each component/work order. He also confirmed that each estimate West Monroe developed has been tailored to NIPSCO's specific AMI Project and NIPSCO's current operating environment.

Next, Mr. Kiergan explained where NIPSCO stood with respect to the communications solution and why this is not a reason for the Commission to find NIPSCO's AMI Project estimate is not a "best estimate." He testified that, while NIPSCO has not yet chosen the specific AMI communications solution ultimately installed, both of these components are extremely mature at this point; i.e., they are not brand new technologies that are hard to model. Specifically, the two primary AMI communications solutions (mesh and point-to-multipoint) are both extremely mature at this point and the scope of the NIPSCO electric AMI program is well-defined, so both solutions were modeled, and mesh was selected as the base case to include in the regulatory filing. Thus, from a detailed modeling perspective, the number of devices needed and the costs for the NIPSCO Electric AMI solution were estimated using vendor-supplied data (benchmark data) regarding meters per communications device in different topologies and were adjusted for the specific geography and customer density seen in the NIPSCO service territory. In addition to materials and labor costs associated with these communication assets, he confirmed that benchmark estimates were used for related network costs, including vendor project management, field network design, communications equipment installation engineering design, field network installation support, integration and configuration, system testing, and network optimization. The sum of these components results in an accurate modeling of the AMI communications solution for NIPSCO and qualifies as a "best estimate."

While acknowledging that every detail about the cost build up was not included in his direct testimony, Mr. Kiergan also testified that NIPSCO provided a working Excel file with all cost inputs to the OUCC in response to a discovery request. He confirmed that every unit cost noted above is delineated in the confidential CBA file titled "OUCC request 3-001 Confidential Attachment A." He also attached this filed to his rebuttal testimony as Confidential Attachment 3-R-A. He stated that it was unclear whether Mr. Alvarez did not review this file, or whether he did not fully understand its contents; however, he reiterated that NIPSCO cited to this file repeatedly in discovery responses and pointed out the exact location of details about certain categories or inputs for the AMI Project.

Next, Mr. Kiergan testified that West Monroe and NIPSCO followed AACE estimating practices in developing this comprehensive CBA and, in addition, maintained consistency with both what NIPSCO has done in the past and with what the Commission has consistently approved. In terms of AACE estimating, he stated the AMI Project's scope was robustly defined, deterministic estimating methods involving a high degree of unit cost line items were used, and the current estimate is supporting a funding request and will be used as a first project control estimate. These characteristics, he said, align the CBA with standardized estimating methodologies and align the estimate with the concept of a "best estimate."

Mr. Kiergan also explained why actual costs or NIPSCO historical costs were not utilized. Specifically, the reality of the situation is that the AMI Project is not like other, traditional TDSIC projects, as AMI is not something NIPSCO has deployed in the past, like transformers, substation components, poles and towers, and communications towers that are included in the TDSIC filing. NIPSCO has no history with AMI and its specific components. Conversely, AMI is not new to the industry and is a mature solution. Additionally, he testified about West Monroe's deep experience in AMI CBAs, and how West Monroe maintains a set of AMI unit cost line items and has used this expertise to develop a comprehensive, robust, and accurate cost model for an AMI deployment in the NIPSCO electric service territory. He also discussed how, when appropriate, West Monroe used NIPSCO-supplied, current-day, cost estimates for specific inputs or activities, such as NIPSCO labor costs for meter replacements or line work and NIPSCO costs for specific customer outreach artifacts (door hangers, mail inserts). Mr. Kiergan reiterated that this modeling experience and capability to modify models and inputs to NIPSCO's specific AMI project scope is specifically why NIPSCO brought West Monroe in to assist in developing the cost estimates for the AMI Project—to leverage West Monroe's expertise for this new type of project. Thus, while actual or RFP-supplied costs are not available, he confirmed that West Monroe and NIPSCO stand by the accuracy and reliability of costs modeled in the CBA.

In response to Mr. Alvarez' testimony about the "likelihood of substantial cost increases" associated with the AMI Program, Mr. Kiergan testified that NIPSCO does not anticipate substantial increases from the modeled costs and explained that there are safeguards in place preventing NIPSCO from implementing major cost increases for the AMI Program in the future. He repeated that West Monroe and NIPSCO created a comprehensive CBA based on current, benchmarked unit cost line items and detailed analysis of a NIPSCO Electric AMI solution. Additionally, he noted a contingency of 10% was included, as is standard in cost estimating at this phase of a project, to account for any pricing differences experienced as NIPSCO moves to RFPs and contracting. These factors result in West Monroe and NIPSCO having a high degree of confidence in the modeled costs and expecting little variance form the overall costs modeled.

From a prevention perspective, Mr. Kiergan noted that NIPSCO does not have the capability to raise AMI Program costs unilaterally with no oversight or constraints. Instead, as part of the formal TDSIC filing, and as further discussed by Ms. Becker, the cost estimates approved by the Commission would be set as the baseline for the AMI Program. Afterward, if NIPSCO wanted to increase the cost for the AMI Project, it would need to do so in a Section 9 tracker/update filing, where it would have to justify any increases to the approved cost estimates. Despite it being outlined in the TDSIC Statute, he said Mr. Alvarez ignored that, to the extent costs were projected to rise even a small amount from the approved cost level, NIPSCO would be required to specifically justify these cost increases and receive an additional regulatory approval for them before being allowed to recover them in the TDSIC tracker.

Mr. Kiergan continued his response to Mr. Alvarez' testimony by discussing how Mr. Alvarez used a comparison to top-line, per-meter cost estimates for I&M and DEI AMI Programs to call into question NIPSCO's overall AMI costs. He testified that a top-line comparison between AMI programs is not valid unless one analyzes the programs in detail and is able to provide a true apples-to-apples comparison, because there are many factors that drive differences in costs for AMI Programs, including: new IT systems included in or excluded from the Program, use of internal versus external labor, the communications network modeled, timeline of deployment, the number and scope of integrations with existing systems, enabled programs included in the Program, and the capability of specific utilities to receive vendor cost reductions based on the size of the utility and associated purchasing power. He explained that each of these items directly impact the overall costs and thus the overall costs on a per-meter basis. Additionally, he said specific items, such as MDMS, integrations, and cybersecurity do not scale linearly based on number of meters, so comparison of these components will cost more for a utility with fewer meters. He concluded that until an analysis of this type enables an accurate comparison, the concept of comparing top-line numbers is not overly informative.

Mr. Kiergan next responded to Mr. Alvarez's claims that a lack of follow-on or AMI-enabled programs included in the CBA adds to the uncertainty of the project, since neither the costs nor the benefits were included. He confirmed that it is not as if West Monroe conducted and NIPSCO filed a "half-baked" or poorly constructed CBA that missed a lot of important things. Citing to his direct testimony, he confirmed West Monroe took an intentionally conservative approach in modeling the benefits associated with AMI, including only those benefits directly attributable to the deployment of and the use of the functionality provided by the AMI system. Even without the benefits of these follow-on programs being modeled, he noted that the CBA showed a net benefit for customers and, had they been included, it would have further bolstered the net benefits of the AMI Project.

Mr. Kiergan confirmed that there are many follow-on programs that are enabled by AMI that can be pursued to maximize the value of the AMI investment. However, he testified that NIPSCO has not yet determined which of these programs it will pursue and understands that any program that is undertaken will not show a return until at least 2025, when the first year of full deployment has been completed, and leaving three years to analyze, select, and address with regulators the plan to deploy selected programs. He testified that many of these programs "have minimal extra costs associated with implementation while potentially providing a high level of incremental benefit or return on the investment." Additionally, these follow-on programs would be stand-alone programs that would utilize AMI functionality to varying degrees, but for which neither the costs nor the benefits would be added to this Electric AMI Project. He believed that as stand-alone programs, their exclusion from the CBA does not create any uncertainty in the results. That being said, he confirmed that NIPSCO is strongly committed to pursuing programs that will maximize the value of the AMI investment for customers and NIPSCO alike.

Mr. Kiergan also testified about the AMI CBA showing the benefits from AMI deployment will not breakeven until 13.5 years (2033) after the project starts. He confirmed that this is normal and to be expected. He noted that the basis of the Electric AMI Project CBA is that in the 15-year model, deployment occurs, benefits start to accrue as meters are deployed, and full benefits begin to be realized when full deployment is completed. These benefits then continue annually for the remaining years modeled (2027-2036) with minimal additional capital required, which matches the benefit period with the capital period. He explained that, as a utility deploys AMI meters, they could begin to wind down the meter reading function, but the maximum benefit would not be realized until all AMI meters are deployed and the meter reading function is minimized. Then, the year after deployment is completed, and each year after that, the operational benefit of reduced meter reading costs would be fully realized without the continued capital costs of new meters and installation experienced during the years of deployment. With this being the case, he stated that there would be no expectation of a break-even during the years of deployment. He said these are investments being made, and it takes time for the investment to "pay itself back."

D. <u>Mr. Thibodeau</u>. Mr. Thibodeau submitted rebuttal testimony for NIPSCO in response to Mr. Collins' criticisms of the NIPSCO's Economic Impact Report, which was originally sponsored by Ms. Becker but was sponsored on rebuttal by Mr. Thibodeau and included as Confidential Attachment 6-R-A. He explained that NIPSCO requested that S&L study and evaluate the economic impact of NIPSCO's projected construction and development expenditures during the six-year period from 2021 to 2026, under what NIPSCO refers to as its "2021-2026 Electric Plan." He noted that the majority of the study S&L performed was limited to capital expenses and investment relating to T&D systems and did not include the economic impact of operation and maintenance expenditures outside of the AMI Project. Specifically, the results of S&L's study and analysis were reported in the Economic Impact Report, which estimates the direct, indirect, and induced impacts of these expenditures on two different geographic regions—Indiana and the remaining United States. Each impact was broken down into the following types: supported employment, labor income, value added (Gross Domestic Product), and total economic output. From these impact types, estimates of wages, federal taxes, and state and local taxes were then calculated.

Mr. Thibodeau further testified that the majority of NIPSCO's economic impact is expected to occur in Indiana, but the analysis focused on the economic impact within Indiana and the United States but contains three geographic regions total – Indiana, the remaining United States, and outside the United States. He noted the impact analysis for planning ("IMPLAN") software was used to estimate the economic benefit of NIPSCO's expenditures and investments categorized as net employment, income, value added to the market, wages injected into the economy, and federal, state, and local taxes.

Mr. Thibodeau also responded to criticisms of or issues taken with the Economic Impact Report by Mr. Collins. After summarizing what Mr. Collins had to say, he first noted that Mr. Collins does not appear to argue that the Economic Impact Report was not properly conducted. He does not seem to claim that the results contained in the report are not valid; rather, he would just prefer an entirely different kind of report or analysis would have been performed. Second, in direct response to Mr. Collins' criticisms, Mr. Thibodeau acknowledged Mr. Collins is correct that the report is not a true "cost-benefit analysis," but said Mr. Collins ignores that the report was not presented as such and does not point to any place in NIPSCO's case-in-chief where NIPSCO claimed that the report was a cost-benefit analysis. Thus, he testified the report did not look specifically at potential rate impacts based on NIPSCO's overall capital investment under the 2021-2026 Electric Plan, nor did it provide an estimated projection of "net economic impact," as this was not the intent. Instead, the intent of the report was to demonstrate the significant economic benefit associated with NIPSCO's planned investments.

Mr. Thibodeau concluded by testifying that the anticipated economic impact on the State of Indiana would be relevant to what benefits are attributable to the Plan, and while they are less directly relevant, the impacts in the broader U.S. would also be relevant. He noted that factors such as positive employment impacts, labor income, state and local tax increases, and the multiplier effect of these factors in the broader economy have direct bearing on whether and how NIPSCO's 2021-2026 Electric Plan are in the public interest. He clarified that the report was the only relevant evidence that should be considered by the Commission, nor is it the only evidence offered by NIPSCO to support overall Plan approval. However, he explained, the report is an important piece of evidence for the Commission to consider, as it is relevant to the Commission's determination of whether the estimated costs of the eligible improvements included in the Plan are justified by incremental benefits attributable to the Plan.

8. <u>Commission Discussion and Findings</u>.

A. <u>Statutory Framework</u>. Ind. Code § 8-1-39-10 permits a public utility to petition the Commission for approval of the public utility's plan for eligible transmission, distribution, and storage improvements, which may include approval of a TED project. The Commission's order must include the following:

(1) A finding of the best estimate of the cost of the eligible improvements included in the plan.

(2) A determination whether public convenience and necessity require or will

require the eligible improvements included in the plan.

> (3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.
>
> If the commission determines that the public utility's TDSIC plan is reasonable, the commission shall approve the plan and authorize TDSIC treatment for the eligible transmission, distribution, and storage improvements included in the plan.

Ind. Code § 8-1-39-10(b).

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

> (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas;
>
> (2) were not included in the public utility's rate base in its most recent general rate case; and
>
> (3) were [among other things] described in the public utility's TDSIC plan and approved by the commission under [Ind. Code § 8-1-39-10] and authorized for TDSIC treatment . . . .

Ind. Code § 8-1-39-2(a).

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

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

Ind. Code § 8-1-39-2(b).

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

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

B. <u>NIPSCO's TDSIC Plan and Eligible Improvements</u>. NIPSCO's TDSIC Plan is comprised of three segments: (1) Aging Infrastructure projects, aimed at maintaining safe and reliable performance while proactively replacing aging, high risk equipment across the system; (2) System Deliverability projects, aimed at maintaining adequate system capacity to reliably serve customer loads; and (3) Grid Modernization projects, intended to modernize NIPSCO's electric grid with technologies that support improved reliability, asset health and condition, and prepare for future customer expectations. NIPSCO's TDSIC Plan and attached appendices identify what projects will be undertaken, when they will be undertaken, and why these projects are necessary and beneficial. The evidence presented demonstrates that the improvements are being undertaken by NIPSCO for purposes of safety, reliability, system modernization, or economic development. NIPSCO also showed that the proposed improvements were not included in its rate base in its most recent general rate case.

The other parties did not challenge the TDSIC Plan on the basis that the projects are not "eligible improvements" under applicable law. Thus, based on the evidence, we find that the projects described in NIPSCO's TDSIC Plan meet the criteria established by the TDSIC Statute and find that the projects are being undertaken by NIPSCO for the purpose of safety, reliability, system modernization, and support of economic development. We further find that the proposed projects are "eligible improvements" as defined in Ind. Code § 8-1-39-2 and were not included in NIPSCO's most recent rate case.

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

NIPSCO's TDSIC Plan proposes approximately five-and-a-half years of defined investment totaling $1,635,535,402. The estimated Plan cost addresses (1) Aging Infrastructure projects (approximately 54% and $753,121,380 (direct capital) of NIPSCO's Plan), aimed at maintaining safe and reliable performance while proactively replacing aging, high risk equipment across the system, such as transformers, electric circuits, and substations; (2) System Deliverability projects (approximately 20% and $281,439,419 (direct capital) of NIPSCO's Plan), aimed at maintaining adequate system capacity to reliably serve customer load; and (3) Grid Modernization projects (approximately 26% and $362,054,616 (direct capital) of NIPSCO's Plan), aimed at modernizing NIPSCO's electric grid with technologies that support improved reliability, asset health and condition, and prepare for future customer expectations. The total cost estimate is $1,635,535,402 inclusive of direct and indirect capital, AFUDC, and O&M. NIPSCO's TDSIC Plan provides year-by-year project details, including cost estimates in a sortable list and an associated summary of the Plan's cost by FERC account. As noted by Ms. Becker on rebuttal, more than one-third (approximately $618 million[1]) of the proposed Plan relates to projects that

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[1] This amount reflects $526 million that was carried over from Electric Plan 1 into the 2021-2026 Electric Plan, and $92 million related to Wood Poles and Circuit Performance projects that were originally included in Electric Plan 1, removed based on judicial interpretation of the prior version of the TDSIC Statute, but included in the proposed Plan based on recent statutory revisions.

were previously approved as part of NIPSCO's Electric Plan 1.

We find that NIPSCO's estimates are sufficiently detailed and reasonably based on the AACE Cost Classification System. The undisputed evidence demonstrates that NIPSCO developed cost estimates for the projects included in the TDSIC Plan using the AACE Cost Classification System. As a general matter, the preliminary engineering for most projects in NIPSCO's TDSIC Plan would support a Class 3 estimate for projects scheduled in the next 18 to 24 months. Projects in later years are considered Class 4 or Class 5 estimates. For Programs, NIPSCO will have completed detailed engineering by the execution year 1 and, these estimates are considered a Class 4. The confidential appendices included in NIPSCO's TDSIC Plan included a risk register, asset registers, project estimates, and unit cost estimates, among other things. The level of detail NIPSCO used to estimate project cost estimates in its TDSIC Plan is consistent with common practice within the industry.

Further, as part of its annual update process, NIPSCO plans to update the Plan with its best estimate by project for each calendar year. The confidential appendices included in NIPSCO's TDSIC Plan will be updated as new, relevant information becomes available during the Plan update process. PCR forms will be provided to support material project estimate changes during the current year for projects. Actual costs (direct capital, indirect capital, and AFUDC) will be included in the Plan update when a given calendar year is closed out.

Industrial Group witness Mr. Collins raised a claim that contingency included in NIPSCO's cost estimates is unnecessary. He did not challenge the amount of contingency but, instead, argued all contingency should be disallowed. In Cause No. 45264, the Industrial Group, through Mr. Collins, raised this same argument. There, we rejected his argument and stated that exclusion of contingency in estimates would actually mean estimates are not "best estimates" as required by the TDSIC Statute. Specifically, on page 23 of the 45264 Order, we found "the exclusion of contingency from the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute." No evidence was offered that would change our findings in this case. Therefore, consistent with our findings when evaluating other TDSIC Plans, including NIPSCO's gas TDSIC Plan in Cause No. 45330 (at page 23) and in IPL's electric TDSIC Plan in Cause No. 45264, we find that including contingency costs in the cost estimate is consistent with the AACE system and with industry practice. We also find that NIPSCO has shown that the level of contingency reflected in its cost estimates is reasonable. Given these considerations, we find the exclusion of contingency from the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute.

In addition to the general challenge raised about NIPSCO's estimation methodology and inclusion of contingency, which was discussed above, the OUCC, through Mr. Alvarez, challenged NIPSCO's cost estimate for the AMI Project. NIPSCO proposes a capital cost estimate of $172,611,997 for the AMI Project, which is based on collaboration between NIPSCO and West Monroe. Mr. Alvarez challenged NIPSCO's cost estimate for the AMI Project, arguing it "is still at its initial stages" and "has a very high degree of uncertainty." He further claimed that "the project has a high possibility of future cost escalations with magnitudes of several factors."

Through its direct and rebuttal testimony and attachments, NIPSCO provided an extensive discussion of both how its cost estimates for the AMI Project were built and what inputs, data, and other information were used as the basis for its individual cost categories and the total project cost. For example, in rebuttal, Mr. Kiergan provided Confidential Attachment 3-R-A, which was the NIPSCO-specific version of West Monroe's confidential and proprietary AMI model. As discussed in his rebuttal testimony and as demonstrated by Confidential Attachment 3-R-A, NIPSCO's cost estimates were not modeled in a top-down approach, where an overall program per meter cost or component-level top-line costs were taken to come up with a total estimate. Rather, the evidence demonstrates that costs in the CBA were built from the bottom-up using a combination of benchmarked and NIPSCO-specific per-unit costs. Mr. Kiergan also confirmed that each estimate West Monroe developed for various components of the AMI Project has been tailored to NIPSCO's specific AMI Project and NIPSCO's current operating environment.

We acknowledge that the AMI Project is different than a more traditional replacement of a T&D asset, which NIPSCO likely would have completed numerous times in the past few years, as the AMI Project will involve a longer timeline and entail a level of planning that replacement of a singular asset would not. However, in its most recent revision to the TDSIC Statute, the General Assembly expressed a clear intent that projects like the AMI Project be allowed as part of a five-to-seven year TDSIC plan. It did so without amending the requirement to provide a "best estimate" or further specifying what would be considered a "best estimate" for advanced technologies, such as AMI. Even so, Mr. Alvarez claims NIPSCO will not be able to provide a "best estimate" for the AMI Project until it develops, issues, and evaluates its RFPs for the various AMI Project components, which would be during the second year of the deployment. As acknowledged by the OUCC in discovery, we have never found or otherwise concluded a company proposing a project under the TDSIC Statute must issue an RFP in order to provide a "best estimate," and we decline to do so here. It would be unreasonable and impractical to require NIPSCO to undertake the time, effort, and expense associated with AMI Project planning, mobilization, system evaluation, initial deployment, and other work that would precede an RFP in 2024 in order for NIPSCO to provide a "best estimate."

NIPSCO explained that, even though it will not be fully executed for several years, the AMI Project is a Class 4 estimate. NIPSCO did not come up with its AMI Project estimate alone; rather, it partnered with and leveraged the experience of West Monroe, a vendor with extensive expertise in this area. Mr. Kiergan explained the numerous AMI business cases the West Monroe team has prepared. For example, he testified that he has personally been involved in more than 15 utility modernization cost benefit analyses and how he has supported implementation and execution of several grid modernization projects similar to the AMI Project. He also discussed how recent benchmarking data was utilized and ultimately expressed confidence in accuracy of the cost estimates being provided. Additionally, it is uncontested that NIPSCO followed AACE estimating practices with respect to all its project cost estimates, including the AMI Project. All of this further supports our finding below that NIPSCO has provided a best estimate for the AMI Project.

Ind. Code § 8-1-39-10 requires the Commission order to include a "finding of the best estimate" of the cost of the proposed improvements. At this juncture, the Commission is not tasked with reviewing actual project costs. After approval of a TDSIC plan, Ind. Code § 8-1-39-9 establishes procedures for TDSIC trackers, providing that "[a]ctual capital expenditures and

TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates." NIPSCO will also utilize Section 9 tracker update filings to provide refined Class estimates for projects in later years of the Plan and, to the extent NIPSCO cost estimates were to exceed those approved herein, they will be evaluated in such filings. Moreover, Ind. Code § 8-1-39-14 establishes a limitation on TDSIC recovery within a 12-month period.

Based on the evidence presented, we find that the record demonstrates that the total, estimated cost of NIPSCO's TDSIC Plan of $1,635,535,402 rests on a sound factual and analytical foundation and is reasonable. This finding applies to the NIPSCO's Plan generally, as well as to the AMI Project specifically. Accordingly, we find the best estimate of the cost of the eligible improvements included in the Plan is the estimate provided by NIPSCO.

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

The evidence of record in this Cause demonstrates that the Aging Infrastructure portion of the TDSIC Plan (which accounts for $753,121,380 (direct capital) of the total Plan) is largely intended to replace assets based upon the condition of the facilities and which is necessary to continue serving its customers safely and reliably while also complying with applicable laws. The evidence of record further demonstrates that the System Deliverability portion of the TDSIC Plan (which accounts for $281,439,419 (direct capital) of the total Plan) is largely intended to ensure NIPSCO is positioned to have system capacity available to continue serving the growing load of its current and future customers. And the evidence also demonstrates that the Grid Modernization portion of the TDSIC Plan (which accounts for $362,054,616 (direct capital) of the total Plan) is intended to modernize NIPSCO's electric grid with technologies that support improved reliability, asset health and condition, and prepare for future customer expectations.

The TDSIC Plan follows the requirements of the TDSIC Statute and achieves the legislative intent of making new and replacement transmission, distribution, and storage system investments for the purpose of safety, reliability, system modernization, and economic development. The eligible investments are essential in protecting the integrity, safety, and reliable operation of the system and will also enhance the ability of NIPSCO and its customers to take advantage of the rapid development of alternative technological options (such as EVs, DERs, etc.).

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

Thus, we find that substantial evidence in this Cause shows that the projects included in NIPSCO's TDSIC Plan will serve the public convenience and necessity.

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

Ms. Becker testified the TDSIC Plan effectively addresses safety, reliability, and system modernization. She stated it is essential in considering the incremental benefit of the Plan to recognize that continued safe, reliable service from the eligible investments in the Plan be compared against the potential for service deterioration and capacity restraint that would occur if these investments were not made. Mr. Vamos testified that, while the Plan addresses several types of eligible investment in the TDSIC Statute, the three main objectives of the Plan are: (1) maintaining safe and reliable performance while proactively replacing aging, high risk equipment across the system; (2) maintaining adequate system capacity to reliably serve customer loads; and (3) modernizing NIPSCO's electric grid with technologies that support improved reliability, asset health and condition, and preparing for future customer expectations.

As reflected in Section 4.B.iv above, Mr. Vamos also provided extensive testimony about the incremental benefits attributable to the Plan. He provided a few examples where the Plan's investments positively impact electric reliability, safety, and grid modernization while resulting in positive economic impact for Indiana. Regarding safety, he testified this is of utmost importance to NIPSCO, its customers, and the broader public, and one of the main objectives of the Plan. Safety will be enhanced when the likelihood of violent failures are mitigated through aging infrastructure replacement. Additionally, the Grid Modernization projects will increase visibility for fault detection and assist in preventing violent failures from occurring as well. Mr. Vamos further testified how the proactive replacement of aging infrastructure will help maintain the reliability of NIPSCO's electric transmission and distribution systems, which are growing older, and therefore riskier, with each passing year. He noted that the Plan targets the highest risk and consequence of failure assets, as identified in NIPSCO's TDSIC Risk Model, and that NIPSCO carefully prioritized the list of planned investments to optimize the benefits of the investments while taking into account execution resources, engineering resources, and system constraints.

Some of NIPSCO's projects allow for benefits to be quantified, while others do not. The Distribution Automation Program Business Case (Confidential Attachment 2-E) monetizes the value of the proposed distributed automation program and demonstrates that investments in DA grid modernization result in a cost savings of approximately $592 million over the period of 20 years, compared against the investment of approximately $52 million for DA grid modernization projects over a 10-year period. For risk-based projects, the Plan represents an optimized risk reduction of approximately 16% versus a break/fix strategy. Below, we also discuss monetized benefits in a cost benefit analysis for the AMI Project.

Several challenges were raised in response to the evidence offered by NIPSCO. First, Mr. Collins challenged the Economic Impact Report prepared by S&L and sponsored by NIPSCO witness Thibodeau. Second, both Mr. Collins and Mr. Hunt criticized the estimated risk reduction benefit. Relatedly, Mr. Collins criticized NIPSCO's performance under certain reliability indices and questioned whether the proposed Plan would have any positive impact on such indices going forward. Finally, Mr. Hunt offered testimony that recommended disallowance of approximately $120 million in projects based on, in essence, an argument that the cost of the projects was too high when compared to the expected risk reduction. We will address each of these arguments briefly.

There is no dispute between NIPSCO and the Industrial Group that the Economic Impact Report offered by NIPSCO was not a measurement of the "net economic impact" attributable to the Plan. This was admitted by NIPSCO and was Mr. Collins' primary criticism. However, as explained by Mr. Collins, the Economic Impact Report was specifically intended to and did measure the economic impact of NIPSCO's projected construction and development expenditures during the period from 2021 to 2026 attributable to the 2021-2026 Electric Plan. The conclusions of the report demonstrate that NIPSCO's Plan is expected to have a significant impact on Indiana's economy, as well as the broader U.S. Although it was focused on the benefits of economic impact, while excluding attendant costs, such as the potential impact on NIPSCO's electric rates, the Economic Impact evidence is relevant to our consideration of the overall benefits attributable to the Plan, as well as how the Plan serves the public convenience and necessity. Additionally, while the report is an important piece of evidence to consider, it is not the only evidence offered by NIPSCO to support overall Plan approval.

Similar to the challenges to the Economic Impact Report, there is no disagreement among the parties that NIPSCO does not utilize a "break/fix" approach for its maintenance practices, but utilizes a proactive maintenance program. However, Mr. Hunt and Mr. Collins alleged that NIPSCO utilizing this as the baseline off of which to estimate its risk reduction was invalid and, thus, NIPSCO's estimated 16% risk reduction is overstated. Mr. Vamos responded by noting that what NIPSCO was comparing is specifically the work proposed under the TDSIC Plan versus not doing any of the work in the Plan and that this theoretical assumption was used to portray the benefit of the Plan and not represent the current operating practices at NIPSCO. Mr. Vamos also noted that a similar challenge was raised and rejected in response to IPL's electric TDSIC plan in Cause No. 45464.

Consistent with our finding in the 45464 Order, we conclude that using a break/fix approach as the baseline from which to compare the expected system risk after the TDSIC Plan is fully executed is valid. That is not to say it is the only acceptable method for conducting a "risk reduction" analysis, but it is a valid means of doing so, as it compares a hypothetical scenario where no additional work is conducted during the Plan to a scenario in which all the projects in the Plan are timely executed. We also emphasize that the risk reduction benefit is only one aspect of NIPSCO's overall Plan benefit.

The most significant challenge raised by the OUCC, other than Mr. Alvarez' challenge to the AMI Project discussed below, was offered through Mr. Hunt. He developed and then conducted an analysis that assigned a dollar amount to each point of "risk" that each project would potentially reduce and, ultimately, recommended disallowance of approximately $120 million associated with 12 discreet projects. He did so on the basis that the costs of these 12 projects was too high when compared to the expected risk reduction.

We acknowledge that the analysis undertaken by Mr. Hunt was, if nothing else, novel and creative. And we also acknowledge the overall cost of NIPSCO's Plan, and to a certain extent each project category, is relevant to our determination of whether the costs of the Plan are justified by the incremental benefits. However, as discussed more fully below, we have significant reservations about applying Mr. Hunt's analysis even as a single point of reference.

Primarily, Mr. Hunt's analysis is problematic because it attempts to require NIPSCO to individually justify each project included in the Aging Infrastructure and System Deliverability categories. As further discussed immediately below related to the benefits and costs of the AMI Project, this is not the evaluation we are required to undertake under Section 10(b)(3) of the TDSIC Statute. The language of this section plainly directs the Commission to evaluate "costs of the eligible improvements included in the plan" and determine if they are "justified by incremental benefits attributable to the plan." (Ind. Code § 8-1- 39-10(b)(3) (emphasis added).) NIPSCO is not and should not be required to justify each-and-every project on a project-by-project basis. We note that Mr. Hunt did not claim that any of the 12 identified projects are not eligible under the TDSIC Statute,[2] nor did he challenge the overall cost of NIPSCO's entire Plan as related to expected benefit. He also did not allege NIPSCO's Aging Infrastructure category of projects was too expensive when compared to the expected risk reduction and other benefits. He narrowly focused on and challenged 12 specific projects.

Mr. Vamos provided extensive testimony about the TDSIC Risk Model and how it was utilized by NIPSCO. He also emphasized that an important component of selecting projects within the Plan is human input and real-world evaluation of how NIPSCO's system is actually designed and performs. He also confirmed that NIPSCO kept cost-effectiveness in mind as it developed the Plan, as the optimization methodology NIPSCO used sought to achieve the greatest risk reduction possible for the dollars invested. Importantly, eight of the twelve projects to which Mr. Hunt applied his analysis were System Deliverability projects, which the OUCC admitted were not aimed at reducing risk,[3] yet Mr. Hunt does not explain this apparent paradox. This is because Mr. Hunt's analysis ignores the nature and need for the specific projects and instead focuses exclusively on cost-per-unit-of-risk-reduction to the exclusion of all other factors—which is a significant shortcoming of his analysis. This is best illustrated by his proposal to eliminate the Marktown Substation project, which Mr. Vamos discussed extensively in his rebuttal testimony. As noted therein, this is one of the most important substations in NIPSCO's system, feeding multiple, large industrial facilities, and it was constructed more than 90 years ago and has an average asset age of 37 years. But, again, Mr. Hunt did not attempt to justify why this specific, important substation replacement project should be excluded—except for including it on a list of 12 projects that were "too expensive." The result is that the operational expertise of the utility in determining high priority projects is rejected in favor of an abstract and myopic focus on one metric to exclude projects regardless of their overall merit.

Accordingly, for all the reasons discussed above, based on the evidence presented, we find that NIPSCO provided sufficient evidence to demonstrate the estimated costs of NIPSCO's TDSIC Plan improvements are justified by incremental benefits attributable to the TDSIC Plan. Our finding applies to the AMI Project as well, which we discuss further immediately below.

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2 For example, Mr. Vamos noted in his rebuttal testimony that 5 of the projects Mr. Hunt argues should be excluded are "carryover" projects that were part of Electric Plan 1. Yet Mr. Hunt does not even acknowledge, let alone substantively discuss, why previously-approved projects should now be disallowed.

3 *See* Petitioner's Exh. No. 8 at Request 1-6.a.

In addition to the general challenges about the benefits of NIPSCO's TDSIC Plan discussed above, the OUCC, through Mr. Alvarez, challenged NIPSCO's AMI Project on the basis that the incremental benefits attributable to this one project are not outweighed by the AMI Project costs. As noted above, NIPSCO proposes a capital cost estimate of $172,611,997 for the AMI Project. AMI technology is unquestionably becoming the norm in the electric industry. As Mr. Kiergan noted, more than half of all Indiana utilities have adopted AMI, and more than 60% of investor-owned utilities in the U.S. and in the states surrounding Indiana have adopted AMI. The OUCC's position was not an outright opposition to AMI technology generally, nor did the OUCC argue that implementation of the AMI Project would not be beneficial to NIPSCO and its customers. For example, Mr. Alvarez testified that "the OUCC does not oppose AMI technology deployment."

Mr. Alvarez challenged the AMI Project's benefits primarily in his discussion of the AMI CBA offered by Mr. Kiergan. Mr. Alvarez criticized the CBA for not including benefits associated with certain "add-on programs," and by saying it was inadequate to validate the actual ratepayer benefits and utility operational benefits that may be achieved in the deployment. He also noted that the benefits from AMI deployment will not breakeven until 13.5 years (2033) after the project starts but also acknowledged NIPSCO forecasts net annual benefits of $21.82 million over the next 10 years, resulting in a net benefit of $53.05 million in 2036. He ultimately argued that NIPSCO should be required to perform additional work and come back to the Commission at a later time with a new, more refined estimate for the AMI Project.

Before we address Mr. Alvarez' direct challenge, we note that the statutorily-required evaluation we are tasked with undertaking is "whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan." (Ind. Code § 8-1- 39-10(b)(3) (emphasis added).) The plain language of this section directs our determination to focus on NIPSCO's TDSIC Plan and its estimated costs and incremental benefits. It does not, for example, require an evaluation of or justification of each project or project category. As discussed immediately above, we have found that the estimated costs of NIPSCO's TDSIC Plan improvements are justified by incremental benefits attributable to the TDSIC Plan. Notwithstanding, we also discuss the benefits related to the AMI Project, which we find below also justify the costs attributable to the AMI Project.

Through the direct testimony of Mr. Holtz and Mr. Kiergan, NIPSCO was clear that it is pursuing deployment of AMI technology to address technological changes that are or will be occurring in the electric industry. Without AMI technology, NIPSCO stated it will not be situated to effectively implement or address issues related to DERs or EVs or offer different rate structures, such as peak-shaving and time-of-use rates. For example, Mr. Holtz emphasized that AMI is foundational for NIPSCO to successfully navigate an environment where customers are pursuing greater electrification, including the increasing penetration of EVs and DERs, and AMI will provide the sub-hourly interval, real-time meter data to reliably balance energy supply and demand, settle for energy supplied to the system at the time it occurs, and properly respond to customer demand increases that will come with higher adoption rates of EVs.

Mr. Kiergan also extensively discussed the AMI CBA in his direct and rebuttal testimony. He explained the process undertaken by West Monroe in its development, as well as its conclusions. Mr. Holtz, as well as Mr. Kiergan, discussed the operational benefits associated with the AMI Project, which drive the majority of the monetized benefits. For example, Operational Benefits equate to about $164.9 million in expected savings. Additionally, Avoided Capital and Additional Cost of Service Reductions benefit categories in combination are expected to yield NIPSCO an additional $41.9 million in operational benefits, thereby enabling NIPSCO to realize a total of $206.8 million benefits. Again, these are the monetized benefits, which do not include the real, but unquantified benefits of other programs enabled by AMI and other qualitative benefits. Mr. Holtz and Mr. Kiergan also outlined several additional categories of expected benefits, including (1) enhancing the customer experience, (2) increasing safety, (3) transforming distribution system operations and improving field work efficiency, and (4) enabling expanded customer engagement and improved distribution operations. Mr. Holtz also noted that the AMI Project would enable NIPSCO to better understand how its customers use energy and better forecast load, which was a recommendation in the Director's Report related to NIPSCO's 2018 IRP.

Mr. Alvarez did not challenge any of the quantified or monetized benefits NIPSCO offered. Nor did he challenge the overall conclusion from the CBA that the AMI Project would result in a $53.05 million net benefit (in nominal dollars) over the 15-year horizon. He also did not challenge the expertise of West Monroe generally or Mr. Kiergan specifically, nor did he contest the accuracy of the proprietary West Monroe model through which the AMI Project's cost estimate was built. Instead, interestingly, he argued that the CBA did not include benefits associated with so-called "add-on" programs which are enabled by AMI, but which NIPSCO has not yet determined it will pursue. Mr. Kiergan explained that many of these programs have minimal extra costs associated with implementation but potentially provide a high level of incremental benefit or return on the investment. Thus, in essence, Mr. Alvarez argues that NIPSCO's CBA understates the strength of and benefits associated with NIPSCO's AMI Project.

While NIPSCO presented a CBA that showed a net benefit in nominal dollars of $53.05 million over the 15-year time horizon, it offered the CBA as only one piece of evidence that supports the AMI Project. However, NIPSCO did not propose the AMI Project purely on the basis of economics to reduce customer costs. Rather, NIPSCO is proposing implementation of the AMI Project to ensure it will be situated to provide the kinds of services its customers will need and expect in the future, and presented a CBA that also demonstrates this is expected to be a cost-effective proposition. For all these reasons, and although a project-specific justification is not required under the TDSIC Statute, we find that the estimated costs of NIPSCO's AMI Project are justified by incremental benefits attributable to the AMI Project.

E. <u>NIPSCO's TDSIC Plan Is Reasonable</u>. As discussed above, NIPSCO's TDSIC Plan satisfies the applicable statutory requirements. The TDSIC Plan is reasonably designed to incrementally maintain or improve safety, NIPSCO's ability to serve its customers, and the reliability and resiliency of NIPSCO's system. The Plan also includes certain projects intended to modernize NIPSCO's electric system.

The record establishes that NIPSCO's Plan is based on a logical approach and sound analysis that presents the best estimate of the cost of the investments. It is also in accordance with Sections 14(a) and 7.8 of the TDSIC Statute. Accordingly, based upon our review of the evidence of record and the foregoing considerations of each component of Ind. Code§ 8-1-39-10, we find that NIPSCO's TDSIC Plan is reasonable and is therefore approved. In accordance with Ind. Code § 8-1-39-l0(b), we authorize TDSIC treatment for the improvements described in NIPSCO's TDSIC Plan, including costs incurred prior to the date of this Order.

F. <u>Plan Development Costs and PS&I Costs.</u> Mr. Vamos explained that the total estimated capital cost of the 2021-2026 Electric Plan includes PS&I costs. As has been NIPSCO's standard practice under Electric Plan 1, PS&I costs for specific projects will be included in the project's land acquisition, preconstruction, environmental, and construction work order (direct capital) and typically will be distributed when the work order is opened based upon the type of typical project planning and sequencing year of project execution. Additionally, the plan development costs will be amortized over the life of the Plan as capital overhead (or indirect capital).

No party presented evidence challenging the amount or recovery of NIPSCO's plan development and PS&I costs. We find and conclude that NIPSCO's proposal is reasonable and is approved.

G. <u>Accounting and Ratemaking.</u> As summarized above, NIPSCO requests Commission approval to defer TDSIC costs until they are recovered through the TDSIC adjustment factor or included in basic rates. Ms. Meece testified that NIPSCO seeks Commission authority to recover approved capital expenditures and TDSIC costs through its existing approved electric TDSIC mechanism. The Commission approved NIPSCO's electric TDSIC mechanism in its 44733 Order, allowing for the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorization to defer, until recovery through the TDSIC, 80% of the post-in-service TDSIC costs of the TDSIC project, including carrying costs, depreciation, and taxes.

NIPSCO witness Ms. Meece testified about three proposed changes to the TDSIC mechanism: (1) recovering projected depreciation and property tax expenses, (2) excluding depreciation expense related to plant retirements resulting from the new TDSIC investments, and (3) recovering O&M expenses.

No party presented evidence challenging the first of these three requests. We find NIPSCO's proposal to recover projected depreciation and property tax expenses is reasonable, and is approved. Additionally, while OUCC witness Lantrip requested that NIPSCO not be allowed to accrue carrying charges only for the period between NIPSCO's expenditure of capital investment and the date of deployment of the AMI Project, no party opposed NIPSCO's request to recover O&M expenses through the TDSIC mechanism. The only rationale offered for his recommendation was that, "[p]er NIPSCO witness Christopher Kiergan, the customer benefits would begin as soon as the AMI project meter deployment begins in 2024."[4]

As noted by Ms. Becker in her rebuttal testimony, Mr. Lantrip cited to no Commission precedent in support of this proposal, likely because no such precedent exists, as we have never

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4 Public's Exh. No. 3 at p. 12, lines 7-9.

conditioned recovery of O&M expenses that meet the statutory definition of "TDSIC costs" under Section 7 upon the in-service date of a capital project. Neither have we delayed accrual of carrying charges. However, each time we have approved O&M expenses as eligible "TDSIC costs," carrying charges were allowed on all deferred amounts beginning when they are recognized in the TDSIC mechanism—not deployment or in-service of some related capital project. As Ms. Becker noted, our prior approvals even included a multi-year project, such as O&M for the System Integrity Data Integration Project, which was approved in Cause No. 44403.

Therefore, we approve NIPSCO's request for recovery of O&M expenses and decline to condition accrual of carrying charges on the date the AMI Project is deployed.

NIPSCO proposed a method of reducing the depreciation expense (representing the depreciation expense associated with the retirement of assets replaced by TDSIC investments) to be recovered through the TDSIC mechanism. This was based on a three-year average retirement rate by FERC account to determine the depreciation reduction adjustment to be applied to NIPSCO's recovery of depreciation expense in its TDSIC tracker filings. Ms. Meece testified, and all parties conceded,[5] this proposed depreciation offset or "netting" methodology was identical to the method the Commission recently approved associated with NIPSCO's gas TDSIC Plan in Cause No. 45330 TDSIC 1.

However, Mr. Lantrip argued for NIPSCO's depreciation adjustment to be based upon historical, actual retirements. Mr. Collins did not take issue with the way NIPSCO proposed to make this depreciation adjustment but did argue that it did not go far enough, as it only accounted for the "recovery of" but not the "return on" portion of the retired assets.

On rebuttal, Ms. Becker explained the difficulties NIPSCO would encounter if it attempted to implement the depreciation adjustment based on historical, actual information instead of a three-year average retirement. She also noted the inefficiencies that could be created if NIPSCO were required to implement a different methodology for its electric TDSIC than has been approved and implemented for its gas TDSIC Plan. Consistent with our approval of NIPSCO's depreciation adjustment in Cause No. 45330, we approve the use of a three-year average retirement as the basis for such adjustment in this case.

Additionally, with regard to Mr. Collins' arguments about potential duplicative or double recovery, we note that we have recently addressed this very same argument offered by the Industrial Group in the context of IPL's electric TDSIC Plan and NIPSCO's gas TDSIC Plan. For example, in the 45330 TDSIC 1 Order (at page 19), we found:

> We agree with Petitioner that the netting of depreciation expense reflected in its proposal has the effect of reducing Petitioner's pre-tax return. We recently approved IPL's netting proposal as appropriately addressing the double recovery concern raised by the OUCC and found that based on the reduction to TDSIC cost recovery, no further adjustment to the WACC was required. Indeed, we commended IPL's approach. Similarly, here we find based on the

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[5] Petitioner's Exh. No. 7 at Request 1-3.d; Petitioner's Exh. No. 8 at Request 1-10-d.

> evidence that it is not reasonable to, as proposed by Mr. Gorman, further effectively adjust the assets that were included in rate base in Petitioner's most recent base rate case. The TDSIC Statute addresses TDSIC costs, not rate-based asset costs. See Indiana Code § 8-1-39-7. Thus, we find Petitioner's proposed depreciation netting addresses the OUCC and Industrial Group's double recovery concerns and that no further depreciation adjustment is necessary. (Emphasis added.)

No additional evidence or distinguishing factors have been offered by the Industrial Group in this proceeding, and we thus decline to reverse our prior orders. We find that NIPSCO's proposed depreciation adjustment or netting methodology addressees the Industrial Group's double recovery concerns and that no further depreciation adjustment is necessary.

H. <u>Other Issues</u>. Mr. Collins took issue with NIPSCO not providing a credit or offset of some type based on two things: (1) potential incremental rate revenue associated with System Deliverability projects and (2) potential O&M reductions associated with and resulting from the AMI Project. We are not persuaded by Mr. Collins' arguments. As Ms. Becker correctly noted in her rebuttal testimony, we have never required such an offset when approving a TDSIC Plan. NIPSCO also affirmed that no TDSIC project is being proposed to serve any individual customer or increasing load from a particular customer; instead, the System Deliverability projects are proposed to ensure NIPSCO's has sufficient capacity available on its electric system to serve expected load and fulfill its statutory obligation to provide reliable, adequate service. There is nothing in the TDSIC that requires such an offset, and, in fact, through Section 11 of the TDSIC , which relates to TED projects, the General Assembly went as far as encouraging utilities to include projects that increase load, without an offset for incremental revenue, for projects that encourage economic development. Additionally, we also note that NIPSCO will be required to file an electric base rate case before the expiration of its TDSIC Plan. Therefore, to the extent NIPSCO will receive some undefined level of "incremental revenue" or realizes some reduction in O&M expenses, this would be only for a short duration following project execution and would be recognized in the required base rate case.

9. <u>Other Matters</u>.

A. <u>Plan Update Process</u>. Ind. Code§ 8-1-39-9(b) provides that a utility shall update its TDSIC Plan at least annually. NIPSCO proposed an annual Plan Update filing (instead of its current semi-annual update filings), which will allow for a more complete update regarding projects that are in-service, project changes, and project estimates, as this annual filing will report on the entire prior calendar year. Ms. Becker confirmed the annual update will continue to include: (1) explanations and testimony for the prior year projects, the majority of which should be complete and in-service; (2) project change explanations and testimony for current-year projects; and (3) updates from parametric estimates to detailed engineering estimates for the future year. In addition, project moves to different years and other plan changes will be included, as they historically have been provided in Cause No. 44733 TDSIC X. While the 2021-2026 Electric Plan will only be updated annually, NIPSCO will continue to file cost updates in a tracker filing twice each year. One tracker filing will be part of the Plan update filing, and the other tracker filing will occur approximately six months later, which will allow NIPSCO to update the costs associated with projects that have been placed in-service and make appropriate adjustments to the TDSIC factor twice each year.

No party took issue with NIPSCO's proposal. We find the proposed Plan Update process outlined by NIPSCO complies with Section 9(b) of the TDSIC Statute and is therefore approved.

B. Confidentiality. NIPSCO filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on June 1, 2021, which was supported by the affidavit of Mr. Vamos, showing that certain information to be submitted to the Commission were trade secrets under Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on June 11, 2021 finding such information to be preliminarily confidential, after which such information was submitted under seal. After reviewing the information, we find this information qualifies as confidential trade secret information pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2. This information shall be held as confidential and protected from public access and disclosure by the Commission and is exempted from the public access requirements contained in Ind. Code §§ 8-1-2-29 and 5-14-3-4.

10. Conclusion. We find that NIPSCO's TDSIC Plan meets the requirements of the TDSIC Statute. However, as required by the TDSIC Statute, NIPSCO will be required to provide specific justification for the Commission to approve the recovery of costs in excess of approved estimates.

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

1. The projects identified in NIPSCO's 2021-2026 Electric Plan constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2;

2. NIPSCO's 2021-2026 Electric Plan is reasonable and approved;

3. NIPSCO is authorized to defer costs associated with the 2021-2026 Electric Plan that are incurred prior to and subsequent to the issuance of an Order in this proceeding until such amounts are recovered through rates;

4. NIPSCO's request to recover operation and maintenance expenses are TDSIC costs pursuant to Ind. Code § 8-1-39-7 under the TDSIC mechanism is approved;

5. NIPSCO's request to recover projected depreciation and property tax expenses under the TDSIC mechanism is approved.

6. NIPSCO's request for authority to defer its plan development and PS&I costs for recovery via NIPSCO's future TDSIC tracker filing pursuant to Ind. Code § 8-1-39-9 and to amortize such costs over the life of the Plan is approved;

7. NIPSCO's proposed process for updating the 2021-2026 Electric Plan in future TDSIC annual adjustment proceedings, and filing TDSIC rate updates separately on a semi-annual basis, under the Cause No. 45557-TDSIC-X is approved; and

8. The information filed by NIPSCO in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from the public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

9. The Order shall be effective on and after the date of its approval.

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

APPROVED: DEC 28 2021

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

Regina K. Joyner Digitally signed by Regina K. Joyner Date: 2021.12.28 14:31:32 -05'00' on behalf of

Dana Kosco
Secretary of the Commission