Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.	)	CAUSE NO. 45772 APPROVED: AUG 02 2023

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

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On September 19, 2022, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.[1] Also on September 19, 2022, Petitioner filed its case-in-chief, workpapers, and information required by the minimum standard filing requirements set forth at 170 IAC 1-5. NIPSCO's case-in-chief included testimony, attachments, and workpapers from the following witnesses:[2]

- Michael Hooper, President and Chief Operating Officer, NIPSCO;
- Erin E. Whitehead, Vice President of Regulatory Policy and Major Accounts, NIPSCO;
- Jennifer L. Shikany, Director of Regulatory Utilities and Optimization, NiSource Corporate Services Company ("NCSC");
- Kevin J. Blissmer, Manager of Regulatory, NCSC;
- Angela Camp, Director of Regulatory and Utility Planning, NCSC;
- Nick Bly, Manager of Corporate Consolidation in Financial Planning & Analysis, NCSC;
- Gunnar J. Gode, Vice President and Chief Accounting Officer, NCSC;
- Patrick L. Baryenbruch, President, Baryenbruch & Company, LLC;
- Ronald E. Talbot, Senior Vice President of Electric Operations, NIPSCO;
- Kelly R. Carmichael, Vice President, Environmental Policy, NCSC;
- Andrew S. Campbell, Director of Portfolio Planning & Origination, NIPSCO;
- Patrick N. Augustine, Vice President in Charles River Associates' Energy Practice;
- Kimberly Cartella, Director of Compensation, NCSC;
- Jeffrey T. Kopp, Senior Managing Director, 1898 & Co.;
- John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC;
- Vincent V. Rea, Managing Director of Regulatory Finance Associates, LLC;
- Jennifer A. Harding, Director of Income Tax Operations for NCSC;
- Melissa Bartos, Vice President, Concentric Energy Advisors;
- John D. Taylor, Managing Partner with Atrium Economics, LLC;
- Judith L. Siegler, Lead Operations Analyst, NCSC; and
- Alison M. Becker, Manager of Regulatory Policy, NIPSCO.

As part of its requested relief, NIPSCO sought approval of an Alternative Regulatory Plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 which would continue, with certain modifications, the existing Rate 831 industrial service structure. Petitioner further asked that the Commission approve the Stipulation and Settlement Agreement on Rate 831/531 Modification ("Rate 831/531 Modification Settlement") between itself and seven current Rate 831 customers.

Petitioner also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on September 19, 2022, which was granted by Commission Docket Entry

[1] On August 15, 2022, NIPSCO provided its notice of intent to file a rate case in accordance with the Commission's General Administrative Order 2013-5. Pet. Ex. 1, Attachment 1-B.

[2] NIPSCO filed additional information on September 20, 2022 and November 15, 2022. NIPSCO filed corrections to its case-in-chief on January 31, 2023 and April 21, 2023. NIPSCO also late-filed Attachments 1-C and 1-D (consisting of the Proofs of Legal Notice Publication and Customer Notice) of Petitioner's Exhibit 1.

dated October 7, 2022. Petitioner submitted the Confidential Information preliminarily granted confidential treatment pursuant to the instructions in such docket entry.

Petitions to Intervene were filed by the United States Steel Corporation ("U.S. Steel"); NLMK Indiana, a division of NLMK USA ("NLMK"); ChargePoint, Inc.; NIPSCO Industrial Group ("Industrial Group");[3] Walmart Inc. ("Walmart"); Citizens Action Coalition of Indiana, Inc. ("CAC"); Indiana Municipal Utility Group ("IMUG");[4] RV Industry User's Group ("RV Group");[5] Midwest Industrial User's Group ("MIUG");[6] and City of Michigan City, Indiana ("Michigan City"). These petitions were granted without objection. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a party.

On October 7, 2022, a Docket Entry was issued establishing a procedural schedule and related requirements and approving certain stipulations the parties filed on September 19, 2022.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held in Hammond, Indiana on December 12, 2022 and in Valparaiso, Indiana on January 4, 2023, at which time members of the public presented testimony.

On January 20, 2023, the OUCC and certain intervenors filed their respective cases-in-chief. For purposes of its case-in-chief, the OUCC prefiled written consumer comments in Public's Exhibit 13 and testimony and attachments from the following witnesses:

- Michael D. Eckert, Director, OUCC Electric Division;
- Mark E. Garrett, President of Garrett Group Consulting, Inc.;
- Wes R. Blakley, Senior Utility Analyst, OUCC Electric Division;
- Cynthia M. Armstrong, Chief Technical Advisor, OUCC Electric Division;
- David J. Garrett, Managing Member of Resolve Utility Consulting, PLLC;[7]
- April M. Paronish, Assistant Director, OUCC Electric Division;
- John E. Haselden, Consultant;
- Brian Latham, Utility Analyst, OUCC Electric Division;
- Kaleb G. Lantrip, Utility Analyst, OUCC Electric Division;
- Peter M. Boerger, PhD, President of Economics Workshop, LLC;[8] and
- Glenn A. Watkins, President and Senior Economist of Technical Associates, Inc.

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[3] The companies that comprise the Industrial Group are Accurate Castings and Kingsbury Castings, BP Products North America, Inc., Cargill, Inc., Cleveland-Cliffs Steel LLC, Enbridge, Linde, Marathon, and USG Corporation.

[4] The municipalities that comprise IMUG are Town of Schererville, Town of Dyer, and City of East Chicago.

[5] The companies that comprise the RV Group are: LCI Industries, Inc., Forest River, Inc., Patrick Industries, Inc., and Keystone RV Company.

[6] The companies that comprise the MIUG are Ball Metal Beverage Container Corporation; Material Sciences Corporation; and Albanese Confectionery Group, Inc.

[7] Pub. Ex. 5 (Depreciation) and Pub. Ex. 12 (Return on Equity).

[8] On February 16, 2023, the OUCC prefiled corrections to Mr. Boerger's testimony.

The Industrial Group prefiled testimony and attachments from James R. Dauphinais and Michael P. Gorman, both Consultants and Managing Principals with Brubaker & Associates, Inc., and Brian C. Andrews, an Associate with Brubaker & Associates, Inc.

Walmart prefiled the testimony and attachments of Alex J. Kronauer, Senior Manager, Energy Services for Walmart.

CAC prefiled the testimony and attachments of Benjamin Inskeep, CAC Program Director, Ron Nelson, Senior Director at Strategen Consulting, and Scott Reeves, Director on the Distributed Energy Resources and Electrification team at the Cadeo Group.

RV Group prefiled the testimony and attachments of Jeffry Pollock, Energy Advisor and President of J. Pollock, Incorporated and Jonathan W. Burke, President and CEO of Tactical Energy Group.

MIUG prefiled the testimony and attachments of Michael R. O'Connell, Vice President of Industrial Solutions at Midwest Wholesale Power Specialists LLC.[9]

U.S. Steel prefiled the testimony of Ralph R. Riberich, Jr., Director of Procurement for U.S. Steel.

IMUG prefiled the testimony of Ted Sommer, Partner with the Firm of London Witte Group, LLC.

On February 16, 2023, the OUCC prefiled cross-answering testimony of Michael D. Eckert and Peter M. Boerger, PhD; the Industrial Group prefiled cross-answering testimony of Brian C. Andrews and James R. Dauphinais; CAC prefiled cross-answering testimony of Ron Nelson and Benjamin Inskeep; RV Group prefiled cross-answering testimony of Jeffry Pollock; U.S. Steel prefiled cross-answering testimony of Tony M. Georgis, Managing Partner of the Energy Practice at NewGen Strategies and Solutions, LLC; NLMK prefiled cross-answering testimony of Frank W. Radigan, Principal, Hudson River Energy Group; and Michigan City prefiled cross-answering testimony of Mayor Duane Parry.

Also on February 16, 2023, NIPSCO prefiled rebuttal testimony, exhibits, and workpapers for the following witnesses:

- Erin E. Whitehead;
- Jennifer L. Shikany;
- Kevin J. Blissmer;
- Patrick L. Baryenbruch;
- Ronald E. Talbot;
- Kelly R. Carmichael;
- Andrew S. Campbell;

[9] On February 3, 2023, MIUG substituted Mr. O'Connell for Matthew D. Alvarez. On February 16, 2023, NIPSCO filed a motion to strike two questions and answers in their entirety. By Docket Entry dated March 3, 2023, the Presiding Officers partially granted NIPSCO's Motion. The version of testimony admitted into the record did not include the struck language.

- Patrick N. Augustine;
- Kimberly Cartella;
- John J. Spanos;
- Vincent V. Rea;
- Melissa Bartos;
- John D. Taylor;
- Alison M. Becker; and
- Alan Felsenthal, Managing Director, PricewaterhouseCoopers LLP.

On March 6, 2023, NIPSCO, the OUCC, Industrial Group, NLMK, and Walmart filed a Notice of Agreement in Principle with Less Than All the Parties, Request to Vacate Evidentiary Hearing Dates, and Motion for Approval of Agreed Procedure Schedule ("Joint Motion"). In the Joint Motion, the parties advised an agreement in principle on all issues in this Cause had been reached.[10] The Joint Motion also included an agreed procedural schedule for settlement in this Cause.

By Docket Entry dated March 7, 2023, the Presiding Officers revised the procedural schedule to accommodate presentation of the settlement and supporting evidence, as well as to establish a post-hearing schedule.

On March 10, 2023, a Stipulation and Settlement Agreement ("Settlement" or "Settlement Agreement") was filed by NIPSCO, the OUCC, Industrial Group, NLMK, U.S. Steel,[11] Walmart, and RV Group (collectively the "Settling Parties").

On March 17, 2023, NIPSCO prefiled the settlement testimony, attachments, and workpapers of Ms. Whitehead, Ms. Shikany, and Mr. Taylor in support of the Settlement Agreement. Also on March 17, 2023, the other Settling Parties filed additional evidence supporting the Settlement Agreement from the following witnesses:

- Michael D. Eckert;
- Peter M. Boerger;
- Michael P. Gorman;
- James R. Dauphinais;
- Ted Sommer;
- Ralph R. Riberich, Jr.;
- Alex J. Kronauer;
- Jonathan W. Burke; and
- Frank W. Radigan.

[10] The Joint Motion indicated NIPSCO was in continuing discussions with all other parties to the proceeding and anticipated some of them would also sign, or not oppose, the settlement. Joint Motion, fn2.

[11] U.S. Steel made a motion to late file its signature page on March 13, 2023, which was granted by Docket Entry on March 24, 2023.

On March 31, 2023, MIUG and Michigan City filed additional testimony of Michael R. O'Connell and Duane Parry, respectively, opposing the Settlement Agreement. Also on March 31, 2023, CAC and ChargePoint filed notices of non-opposition to the Settlement.

On April 10, 2023, NIPSCO prefiled the settlement reply testimony of Ms. Whitehead, Mr. Campbell, and Mr. Taylor and the Industrial Group prefiled settlement reply evidence of James R. Dauphinais.

Also on April 10, 2023, NIPSCO, the Industrial Group, and NLMK jointly filed an objection and motion to strike MIUG Witness O'Connell's opposition testimonies. On April 20, 2023, MIUG filed its response, along with alternative revised testimonies of Mr. O'Connell. On April 24, 2023, the moving parties withdrew their objection to Mr. O'Connell's revised Rates 526/532/533 testimony and proposed that with the removal of three additional questions and answers, specifically questions and answers 30, 31, and 32, from Mr. O'Connell's Rate 531 testimony, joint movants would withdraw their objection to the remainder of Mr. O'Connell's revised Rate 531 testimony.[12] MIUG agreed to joint movants' proposal prior to the hearing. At the hearing, the version of testimonies admitted into the record for Mr. O'Connell reflected the agreement and joint movants withdrew their objection and motion to strike.

A public evidentiary hearing was conducted in this Cause starting at 9:00 a.m. on April 26, 2023, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the evidentiary hearing, the Settlement Agreement and all of the direct, cross-answering, rebuttal, and settlement, opposing settlement, and settlement reply testimony and exhibits of each party were offered and admitted into the record.

The Commission, based upon applicable law and the evidence, finds as follows:

1. <u>Notice and Jurisdiction</u>. Legal and timely notice of the public hearings held in this Cause was given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a) and an "energy utility" as that term is defined in Ind. Code § 8-1-2.5-2. NIPSCO has also elected to become subject to Ind. Code § 8-1-2.5-6. NIPSCO caused to be published the filing of its petition pursuant to Ind. Code §§ 8-1-2-61 and 8-1-2.5-6 and mailed notice to its customers pursuant to 170 IAC 4-1-18(C). The Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. <u>Petitioner's Organization and Business</u>. NIPSCO is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders retail electric utility service to more than 483,000 retail customers located in all or part of the following Indiana counties: Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White. Additionally, NIPSCO is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and is a member of Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization ("RTO") operated under FERC's

[12] As part of the agreement with MIUG to further revise Mr. O'Connell's prefiled Rate 531 testimony by removing questions and answers 30, 31, and 32, the Industrial Group, as a joint movant, agreed not to offer Mr. Dauphinais' pre-filed settlement reply testimony into evidence at the evidentiary hearing.

authority that controls the use of NIPSCO's transmission system and the dispatching of NIPSCO's generating units.

NIPSCO owns, operates, manages, and controls electric generating, transmission and distribution plant and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, distribution and furnishing of electric energy, heat, light, and power to the public. NIPSCO classifies its property in accordance with the Uniform System of Accounts as prescribed by FERC and approved and adopted by the Commission.

3. Existing Rates. The Commission approved NIPSCO's current electric basis rates and charges in its December 4, 2019 Order in Cause No. 45159 ("45159 Order"). The petition initiating Cause No. 45159 was filed with the Commission on October 31, 2018; therefore, in accordance with Ind. Code § 8-1-2-42(a), it has been more than 15 months since NIPSCO filed its most recent petition for an increase in basic rates and charges and the filing of NIPSCO's Petition in this Cause.

In the 45159 Order, the Commission approved an ARP for NIPSCO's large industrial service structure, which is embodied in NIPSCO's existing Rate 831. Rate 831 has three tiers of service. All customers on Rate 831 must sign a contract which expires the earlier of five years or the approval of rates in NIPSCO's ensuing general rate case. Each Rate 831 customer must take a minimum of 10 megawatts ("MW") of Tier 1 firm service. By default, Tier 2 service is non-firm curtailable service, and NIPSCO will register as load modifying resource ("LMR") at MISO that portion of a customer's Tier 2 contract demand for which capacity is not procured through MISO's planning reserve auction ("PRA") or contracted through a third party. Under Tier 2, the customer will take all energy at the MISO Day-Ahead Locational Marginal Price at the applicable company Load Zone. Tier 3 is also, by default, non-firm curtailable service, and NIPSCO will register as a LMR at MISO that portion of a customer's Tier 3 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party. Under the Tariff, NIPSCO will only register a single LMR for any non-firm load if a customer chooses to take both Tier 2 and 3 service. NIPSCO, as the MISO Market Participant, will register participating customers as an Asset Owner at MISO, which will allow the customer access to the MISO Market Portal to carry out MISO Asset Owner functions. 45159 Order, pp. 40-41. The Commission approved the ARP and a Rate 831 Settlement and Implementation Agreement among fewer than all parties. *Id.* at pp. 151-157, 170. Under the Rate 831 Settlement and Implementation Agreement, rates were designed based upon an assumed subscribed Tier 1 contractual demand of 194.556 MW. There are seven large industrial customers who have executed contracts and are currently taking service pursuant to Rate 831.

4. Test Year and Rate Base Cutoff. As authorized by Ind. Code § 8-1-2-42.7(d)(1), Petitioner proposed a forward-looking test period using projected data, with the test year used for determining Petitioner's projected operating revenues, expenses, and net operating income being the 12-month period ending December 31, 2023. NIPSCO is utilizing the test year end, December 31, 2023, as the general rate base cutoff date. The historical base period is the 12-month period ending December 31, 2021.

5. <u>NIPSCO's Requested Relief</u>. NIPSCO seeks a general increase in rates and charges and approval of new schedules of rates and charges, including modifications of language in its tariff. By its Petition, NIPSCO requested approval of a new variable cost tracker ("VCT") that would move approximately $102 Million out of its current base rates and into the new VCT. Including both the projected revenues from the new VCT and the requested rate increase from base rates, NIPSCO requested Commission approval of an overall annual increase in revenues of approximately $395 Million, or approximately 25.85%. NIPSCO proposed to implement the requested base rate revenue increase in two steps on a phased-in basis. Step 1 would be upon issuance of the Commission's Order and based upon actual rate base and capital structure as of June 30, 2023, and Step 2 would be based upon actual rate base and capital structure as of the end of the test year. What is effectively a third step would take effect upon approval of the VCT. NIPSCO's proposed rates would capture within rate base the cost of NIPSCO's investment in several renewable joint venture projects that were approved in Cause Nos. 45194, 45310, 45524, and 45462, specifically Rosewater Wind, Crossroads Wind, Crossroads Solar, and Dunn's Bridge I Solar, respectively. NIPSCO also sought:

- approval of new common and electric depreciation accrual rates and amortization periods for regulatory assets;
- authority to remove Off System Sales margins from its RTO tracker and instead to pass back 100% of Off System Sales revenues net of expenses through the fuel adjustment clause ("FAC");
- authority to modify joint venture accounting authority so as to combine reserve accounts for purposes of passing joint venture cash back to customers;
- approval of a new station power rate for renewable wholesale generation facilities;
- approval of a new electric vehicle fast charging rate for use at NIPSCO-owned public electric charging stations;
- authority to file a docketed proceeding outside of a general rate case seeking authority to implement a tax rate modification mechanism, in the event of a change in state or federal income tax rates;
- review of the FAC earnings bank;[13]
- approval of a new ARP to implement a proposed low income program; and
- various accounting authorities, including approval of regulatory accounting authority for pension and other post-retirement benefits ("OPEB"), for cost of removal at coal-fired generation assets following the retirement of Michigan City Unit 12, for discounts provided pursuant to the Economic Development Rider, and costs to be recovered through the proposed VCT until such costs are recovered through the VCT.

Prior to filing its Petition, NIPSCO negotiated with its seven large industrial customers taking service under Rate 831. Each of these customers is currently taking service pursuant to a contract that would have expired by its terms upon approval of new rates in this case. Under the provisions of the Rate 831 tariff, upon the expiration of the current contracts, each of those customers could elect to execute a new contract reducing their Tier 1 firm contract demand to as low as the tariff minimum of 10 MW. Had each elected to do so, the Rate 831 demand for cost of

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[13] NIPSCO sought essentially this same review in Cause No. 38706 FAC 136. The Commission has already determined the issue raised by NIPSCO, thus rendering moot this aspect of Petitioner's request.

service and revenue allocation purposes would decrease from the current level of 194.556 MW to 70 MW. NIPSCO presented as part of its case-in-chief the Rate 831/531 Modification Settlement to resolve this risk. Pet. Ex. 2, Att. 2-B.

The Rate 831/531 Modification Settlement provides that 180 MW of production-related demand costs would be allocated to Rate 531 in this rate case based upon the 4 coincident peak ("CP") method, and further provides for transmission demand to be allocated based upon the 12 CP method. These allocation methods are consistent with how production- and transmission-related demand was allocated in Cause No. 45159. Rates for Rate 531, however, would be designed using the seven customers' combined, committed, Tier 1 firm demand of 170 MW, thereby retaining most of the firm load currently served under Rate 831. The current Rate 831 customers agreed to enter into new contracts that would be effective until the earlier of the effective date for new rates under NIPSCO's next electric rate case filing after this case or May 31, 2026. The Rate 831/531 Modification Settlement reserves the right of the customers to reduce their demand at the expiration of these contracts consistent with the terms of NIPSCO's tariff. Further, recognizing that the 180 MW of production-related demand allocated to the Rate 531 customers will exceed the actual contractual Tier 1 demand subscriptions, the 831/531 Modification Settlement provides that in future rate proceedings the cost allocation to Rate 831 (and any successor rate) will continue to move the class toward the actual cost of service based on actual contract demands.

In all other respects, except minor modifications, the Rate 831/531 Modification Settlement preserves the existing Rate 831 terms and conditions of service approved as an ARP in Cause No. 45159, including, but not limited to: the designation of only Tier 1 load as "firm load for transmission, distribution, and storage system improvement charge ("TDSIC") revenue allocation purposes"; the methodology to establish tracker allocations; and the continuation of terms related to the "Adjacent Affiliate Qualified Facility Premise Transmission Charge."

6. <u>Opposition, Rebuttal, and Cross-Answering</u>. The OUCC and intervenors raised numerous challenges to NIPSCO's filing, including challenging rate base, rate of return, operation and maintenance ("O&M") expenses, depreciation rates, rider proposals, cost of service allocation, and rate design. The extent to which these parties disagreed with each other is shown in their cross-answering testimony. The extent to which NIPSCO disagreed or agreed with the OUCC and intervenors was addressed in NIPSCO's rebuttal evidence.

7. <u>Settlement Agreement</u>. The Settling Parties' witnesses presented testimony in support of the Settlement Agreement. They discussed the terms of the Settlement Agreement and explained how the Settlement Agreement resolves all issues presented in the case in a fair and reasonable manner. This includes issues related to the revenue requirement, rate design, approval of the 831/531 Modification Settlement, and the establishment of an Environmental Cost Tracker ("ECT") as a revised replacement for the proposed VCT. The terms of the Settlement Agreement specifically state that it is a settlement of all the issues among all the Settling Parties in this Cause. In addition to the Settling Parties, CAC, ChargePoint, and IMUG agreed not to oppose the Settlement.

According to Mr. Eckert, if approved, the Settlement Agreement will provide certainty regarding critical issues, including revenue requirements, authorized return, and the allocation of NIPSCO's revenue requirement among its various rate classes. Pub. Ex. 16 at 2. Mr. Gorman testified that despite the number of complex issues in the case and the parties' sometimes divergent views on those issues, they were able to reach resolution of the case, as well as two other pending matters that impacted NIPSCO's rates, through the negotiation process. IG Ex. 6 at 6.

The Settling Parties' witnesses conveyed that the Settlement Agreement is a product of a diligent effort by all Settling Parties to reach a comprehensive result. The Settling Parties agreed that the complexity of the issues and the diversity of the Settling Parties dictated the need for compromise on the part of each party involved, and the Settlement Agreement, taken as a total package, reflects a delicate balance that accommodates the interests of all Settling Parties in a reasonable manner. Pet. Ex. 2-S at 17; Pub. Ex. 16 at 2; IG Ex. 6 at 6; NLMK Ex. 2 at 1-2, 5; RV Group Ex. 4-S at 3-4; U.S. Steel Ex. 3 at 5; Walmart Ex. 2 at 6-7.

OUCC Witness Eckert testified the nature of compromise includes assessing the litigation risk that exists in a contested proceeding. He said that while the Settlement Agreement represents a balance of all interests, given the number of benefits provided to ratepayers as outlined in the Settlement Agreement, the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, supported by evidence, and should be approved. Pub. Ex. 16 at 2. Industrial Group Witness Dauphinais added, this rate case raised a broad array of complex issues on a spectrum of subjects, with numerous parties asserting a panoply of views, yet the Settling Parties were able to find consensus on the terms of a comprehensive Settlement Agreement resolving the entirety of the case. Particularly with respect to the issues concerning cost of service, Rate 531, subsidy mitigation, Rate 532, and the new ECT, Mr. Dauphinais stated the Settlement Agreement provides a reasonable resolution that balances the interests of the diverse parties consistent with sound ratemaking policies and principles. IG Ex. 7 at 9. U.S. Steel Witness Riberich testified that approval of the Settlement Agreement as it is written is consistent with the public interest because the Settlement Agreement represents a comprehensive resolution of all the issues in this proceeding by the Settling Parties. He said the Settling Parties' evidence reflects their agreement that the Settlement resolves all disputed issues surrounding NIPSCO's revenue requirement, cost of service, and rate design and provides NIPSCO with an opportunity to earn sufficient revenues to provide reasonably adequate service and a fair return on its investment. Per Mr. Riberich, the Settlement Agreement also balances the interests of the utility's current and future customers in receiving reasonable service at a fair cost. U.S. Steel Ex. 2 at 5.

A. <u>Overview</u>. NIPSCO Witness Whitehead explained that the specific objectives addressed in the Settlement Agreement included: (1) resolution of the revenue requirements issues; (2) resolution of issues related to customer charges; (3) resolution of issues relating to Proposed Rate 531 and all other revenue allocation issues (including proposals related to Rates 526 and 550); (4) proposed implementation of an ECT; and (5) resolution of issues relating to NIPSCO's proposed low income program. Pet. Ex. 2-S at 2-3.

Ms. Whitehead noted that the Settling Parties agree that NIPSCO's base rates will be designed to produce the gross revenue amount of $1,767,260,404 prior to application of surviving Riders, plus amounts NIPSCO will recover through the new ECT, which relates to NOx emissions allowances and variable chemical costs at NIPSCO's coal-fired generating stations. These ECT costs are forecasted to be approximately $30 Million per year. Pet. Ex. 2-S at 3-4. Industrial Group Witness Dauphinais testified that the remaining $72 Million that NIPSCO originally proposed to include in its new tracker would remain embedded in base rates, and allocated between classes on the same basis as those costs were allocated in Cause No. 45159. IG Ex. 7 at 9. Ms. Whitehead explained that under the Settlement Agreement, the total increase in base rates plus the forecasted ECT results in a revenue increase from current base rates of approximately $291.8 Million. This results in a reduction of approximately $103.2 Million from the amount NIPSCO originally requested in its case-in-chief. Pet. Ex. 2-S at 4.

On cross-examination, Industrial Group Witness Gorman was asked to compare this Settlement Agreement reduction to his originally proposed revenue requirement reduction. He originally proposed a reduction in NIPSCO's proposed revenue requirement of $164 Million, but that included Mr. Gorman's proposal to switch to a levelized return on coal generation regulatory assets rather than the declining balance plus revenue credit that was approved in the 45159 Order. Without this differential treatment, Mr. Gorman testified that the $103 Million reduction was within approximately $40 Million of his case-in-chief recommendation. Tr. at C-37 to -38.

Mr. Eckert explained that the Settlement Agreement addresses the issue of affordability, noting the Settlement Agreement reduces NIPSCO's requested revenue increase in several ways. As an example, he noted NIPSCO's rate base request is reduced by $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660. He further explained that the Settlement Agreement removes: (1) $25 Million in fuel costs; (2) $5.8 Million in vegetation management expense; (3) $26.6 Million related to the amortization period for retired coal-fired generating units; (4) $8.8 Million related to the amortization period for retired coal-fired generating Units 14 and 15; and (5) other costs identified in his testimony and the Settlement Agreement. He said that the Settling Parties agreed to an annualized combined basic rate and rider revenue requirement increase of $291,804,809, which is a $103,205,168 or a 26.12% reduction from NIPSCO's as-filed request increase of $395,009,258. Pub. Ex. 16 at 2-3. As shown in Joint Exhibit 1, Settlement Agreement Attachment 1, the average residential electric customer using 668 kilowatt hours ("kWh") per month, paying approximately $120 in September 2022 when the case was filed, will see an overall increase of approximately $12.37 per month, or 10.3%, spread over multiple months. By comparison, NIPSCO's initial case-in-chief included a requested monthly increase of approximately $19.69, or 16.5%.

NIPSCO Witness Whitehead supported the Settlement Agreement's stipulated return on equity ("ROE") of 9.80% and NIPSCO Witness Shikany presented all the settlement adjustments in her settlement testimony. Pet. Ex. 2-S at 4 and Pet. Ex. 3-S at 8-22.

B. Revenue Requirement. The Settlement Agreement provides that NIPSCO will withdraw its proposed VCT and instead establish a new ECT. The ECT will recover fewer categories of costs than the proposed VCT, and the forecasted annual costs to be recovered through the ECT are $29,880,196, comprised of variable chemical expenses and NOx emissions allowances. The remaining costs NIPSCO initially proposed to recover through the VCT will be excluded from the ECT and will instead continue to be recovered through base rates allocated on the same basis as those costs were allocated in NIPSCO's last base rate case, Cause No. 45159.

The Settlement Agreement provides that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount originally requested by NIPSCO in its case-in-chief. The agreed-upon revenue requirement reflects the depreciation study and accrual rates and amortization provided in the Settlement Agreement. The stipulated revenue requirement is calculated to produce an authorized net operating income ("NOI") of $402,900,940. NIPSCO Witness Shikany described the Step 2 revenue requirement and sponsored the supporting schedules. Pet. Ex. 3-S.

C. Original Cost Rate Base, Capital Structure and Rate of Return. The Settlement provides that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settlement provides that NIPSCO should be authorized a fair rate of return of 6.80%. The Settlement provides for a projected net original cost rate base at Step 2 of $5,925,013,822, inclusive of materials, supplies, production fuel, and regulatory assets. This amount reflects that forecasted additions to Renewable Energy Joint Venture Investments will be reduced to reflect the additional Investment Tax Credit NIPSCO will receive for Dunn's Bridge I, as reflected in NIPSCO's rebuttal alternative revenue requirement filed position. NIPSCO's current estimate is that there will be a reduction in additions to forecasted Joint Venture Regulatory Assets of $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660. However, the Settlement Agreement provides that actual reductions will be based on final project cost, which could be slightly more or less.

The Settlement also provides for NIPSCO's forecasted capital structure, including its Prepaid Pension Asset and Post-Retirement Liability at zero cost as reflected in NIPSCO's direct and rebuttal testimony, and a stipulated return on equity of 9.80%. The Settlement provides for the following forecasted capital structure at Step 2:

	Dollars	Cost %	Weighted Average Cost of Capital %
Common Equity	$4,564,821,051	9.80%	5.06%
Long-Term Debt	$3,233,952,976	4.66%	1.70%
Customer Deposits	$59,541,950	5.63%	0.04%
Deferred Income Taxes	$1,393,665,855	0.00%	0.00%
Post-Retirement Liability	$13,945,116	0.00%	0.00%
Prepaid Pension Asset	$(424,946,780)	0.00%	0.00%
Post-1970 ITC	$640,278	7.67%	0.00%
Totals	**$8,841,620,445**		**6.80%**

In its case-in-chief, NIPSCO had proposed a 10.4% ROE and several intervenors, including the OUCC and Industrial Group, advocated for a considerably lower ROE. The testimony in support of the Settlement Agreement explained that as a result of the negotiations, a compromise was reached, resulting in a 9.80% ROE. The Settlement Agreement ROE is within the range of ROE originally recommended for NIPSCO by Mr. Gorman (i.e., 9.00% to 9.90%). Mr. Gorman testified that 9.80% was reasonable for NIPSCO given the balance of the compromises reflected in the Settlement Agreement. IG Ex. 1 at 3. NIPSCO Witness Whitehead explained that if NIPSCO's ROE is set too low, it could lead to financial insecurity that would place increased risk on NIPSCO's ability to attract capital, which could also challenge NIPSCO's ability to obtain the capital necessary to continue to provide safe, reliable, and affordable service to its electric customers. Pet. Ex. 2-S at 4. Mr. Eckert testified that the OUCC found the agreed ROE reasonable and in the interest of ratepayers. Further, the ROE component of the weighted average cost of capital used in each of NIPSCO's capital riders will be 9.80%. Pub. Ex. At 5.

Ms. Whitehead explained that settlement agreements are not precedential and noted that an ROE of 9.80% is five basis points lower than NIPSCO's recently settled gas base rate case in Cause No. 45621 and ten basis points lower than what was agreed to in the Stipulation and Settlement Agreement on Less Than all the Issues in NIPSCO's last electric base rate case ("Revenue Settlement"). She said for all these reasons, the Settlement Agreement represents a reasonable outcome related to ROE in this proceeding. She further noted that the Settlement Agreement provides at Section C.4. that it "has accounted for the overall level of risk presented to NIPSCO by the Settlement Agreement." She explained this evidence shows that the concerns of the RV Group have been factored into the stipulated ROE. Pet. Ex. 2-S at 5-6.

OUCC Witness Eckert testified that a lower ROE benefits ratepayers by reducing the return on rate base reflected in customers' rates. He added that from the OUCC's perspective, using a 9.80% ROE for determining NIPSCO's revenue requirement in its base rates and in NIPSCO's ongoing capital riders more accurately reflects NIPSCO's risk profile than the proposed 10.40% ROE. Additionally, Mr. Eckert testified, the lower ROE reduces the return on capital investment that consumers must pay through capital riders between rate cases. Thus, he said, the Settlement Agreement establishes a balanced plan that is in the interest of ratepayers while still preserving the financial integrity of NIPSCO. Pub. Ex. 16 at 5-6. Mr. Kronauer testified that while the 9.80% ROE set forth in the Settlement Agreement is not as low as Walmart would have advocated for in litigation, Walmart believes that for purposes of settlement a 9.80% ROE provides NIPSCO the opportunity to earn a fair return while still protecting customers' expectations of safe and reliable service at just and reasonable rates. Walmart Ex. 2 at 2-3.

D. Depreciation Rates and Amortization. In its case-in-chief, NIPSCO presented the testimony and the depreciation study of John R. Spanos, who calculated new common and electric depreciation accrual rates based upon the average service life ("ALG") method, as opposed to the equal life group ("ELG") method that had been previously approved for NIPSCO. This change from ELG produced a reduction in depreciation expense from what it would have been of $45,670,313. Pet. Ex. 15 at 23. OUCC Witness D. Garrett proposed several service life changes, recommended mitigation to growth in negative net salvage percentages, and proposed other changes. OUCC Witness Armstrong proposed to include in the costs of decommissioning the costs of coal combustion residual ("CCR") remediation at NIPSCO's Michigan City and Schahfer Generating stations, which Mr. D. Garrett included in his depreciation calculations. The OUCC's recommended depreciation accrual rates produced a reduction of approximately $8.9 Million from the rates recommended by Mr. Spanos. Pub. Ex. 5 at 6. Industrial Group Witness Andrews also recommended changes to Mr. Spanos's depreciation rates that would have produced a reduction from NIPSCO's proposed rates of $11.1 Million. IG Ex. 3 at 4. On cross-answering, Mr. Andrews opposed Ms. Armstrong's proposal to include the CCR decommissioning costs in NIPSCO's approved depreciation rates. IG Ex. 5 at 2.

The Settlement provides that NIPSCO's proposed depreciation accrual rates should be approved with the following exceptions and requirements:

- The amortization period for retired coal-fired generating units and the regulatory assets resulting from regulatory accounting authorized by the 45159 Order shall be extended to conclude June 30, 2034. This produces a reduction of approximately $26 Million in depreciation expense and an additional reduction of approximately $8.8 Million for the amortization of the regulatory asset resulting from the retirement of Schahfer Units 14 and 15.
- Pro forma depreciation expense will be increased approximately $9.8 Million to reflect additional demolition costs for Schahfer and Michigan City.
- NIPSCO will move to stay Cause Nos. 45700 and 45797, and upon Commission approval of all terms of the Settlement Agreement, NIPSCO shall move to dismiss both cases. In the event the Settlement is not approved in its entirety and with respect to NIPSCO's recovery of costs in relation to the projects proposed in Cause No. 45797, the non-NIPSCO parties in Cause No. 45797[14] agree to not object on the basis of the timeliness of the Petition in that Cause or issuance of a Commission order in that Cause, to recovery of costs incurred by NIPSCO after June 1, 2023, in relation to the projects proposed in that Cause. In the event the Commission rejects the Settlement, NIPSCO will move to lift the stay in those proceedings, and except as otherwise agreed to above with respect to Cause No. 45797, litigation will resume in both Causes, with all parties able to take any position in the Causes as may be justified by the law and the facts and that are not inconsistent with the terms of the Settlement.
- Depreciation rates for non-coal-fired generation assets shall be reduced, to produce an additional $9.5 Million reduction.

As required by the Settlement, Ms. Shikany sponsored the depreciation accrual rates that reflect these changes to NIPSCO's as-filed depreciation accrual rates in Petitioner's Exhibit 3-S, Attachment 3-F-S.

Ms. Whitehead stated a key part of the over $100 Million reduction in revenue requirement is the Settlement terms reducing depreciation expense and extending the coal amortization period. She explained that the Settling Parties agreed to an increase in depreciation expense to recognize demolition costs but that increase reflects a corresponding agreement to stay and ultimately dismiss two federal mandate proceedings pending at the Commission in Cause Nos. 45700 and 45797, which could have resulted in tracking those costs. In its direct case, NIPSCO had already proposed to change its depreciation methodology to mitigate the requested rate increase. She said all these reductions in expenses result in a very large decrease in cash flow available to NIPSCO, which increases the need to finance expenses and capital investments. Ms. Whitehead further explained that the Settlement Agreement reflects NIPSCO's agreement to these various terms, which, from NIPSCO's point of view, link directly to the ultimate agreement on ROE. Pet. Ex. 2-S at 5.

Ms. Whitehead said the $9.8 Million increase in depreciation expense for Schahfer and Michigan City relates to costs proposed for recovery in Cause Nos. 45700 and 45797 under Ind. Code ch. 8-1-8.4, totaling approximately $93 Million. She explained that assuming approval of the Settlement Agreement, all costs sought for recovery in those proceedings will instead be addressed in base rates. The Settlement also provides that NIPSCO will not file federal mandate cases pursuant to Ind. Code ch. 8-1-8.4 to recover costs to satisfy any asset retirement obligations

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[14] This includes the OUCC, Industrial Group, and CAC.

associated with coal-fired generation. Instead, NIPSCO will debit FERC Account 108 for reasonable and prudent costs incurred for removal costs associated with coal-fired generation per the FERC Uniform System of Accounts, which entry will be reflected in future depreciation studies. NIPSCO will seek to adjust its future depreciation studies to reflect reasonable and prudent retirement costs.

The Settlement also provides for the following changes to NIPSCO's proposed amortization expense:

- The Cause No. 45159 regulatory asset amortization expense will be adjusted by an $8.22 Million annual reduction, based upon an issue identified by Mr. Gorman.
- There will be a $1.7 Million annual reduction from moving the amortization periods for COVID and Rate Case Expense regulatory asset balances from two to four years.
- There will be a $3.1 Million annual reduction from moving the amortization period for federal mandate cost adjustment ("FMCA") and TDSIC regulatory asset balances from four to seven years.

At the end of all amortization periods, the Settlement provides that NIPSCO will make a compliance filing to remove the amortization from the revenue requirement and will adjust rates accordingly.

Industrial Group Witness Gorman explained that per Sections 3(a) and 3(b) of the Settlement Agreement, the Settling Parties agreed to numerous changes to NIPSCO's proposed depreciation and amortization expense. Among these are a reduction of $9.5 Million in depreciation expense due to adjustments to the depreciation rates for non-coal-fired generation consistent with adjustments proposed by the Industrial Group and the OUCC; a total reduction of about $4.8 Million annually due to the modification of the amortization period for several regulatory assets; and an annual reduction of $8.22 Million in amortization expense for regulatory assets established in Cause No. 45159. Mr. Gorman added that the depreciation expense was further reduced by about $26.0 Million by adjusting the recovery period for remaining coal-fired generation units as initially authorized in the 45159 Order to expire on June 30, 2034. IG Ex. 6 at 4.

The Settling Parties also agreed that regulatory accounting for cost of removal for NIPSCO's coal-fired generation-related assets should be approved as outlined in Petitioner's Exhibit 3. Specifically, Ms. Shikany testified as follows:

> Q. With cost of removal removed from the regulatory asset, how are the closure costs of Schahfer being accounted for?
>
> A. The estimated costs of removal associated with the retired units will be collected through depreciation rates applicable to the same coal-fired generation FERC assets remaining in service at Schahfer and Michigan City. As costs are incurred, NIPSCO will debit FERC Account 108, Accumulated Depreciation, for those actual costs, consistent with the FERC Uniform System of Accounts. Subsequent

depreciation studies will continue to include cost of removal costs for all coal-fired generation assets until all coal units are retired.

Q. What happens if the incurred cost of removal is different than the amounts previously collected through depreciation rates once all coal-fired generation assets are retired?

A. Under normal circumstances, the estimated cost of removal collected remains in the same FERC account as the asset while the asset was used and useful. With NIPSCO's planned retirement of the entire coal-fired generation fleet by 2028, not all demolition and closure activities will be completed by the retirement date, meaning once retired, there will be no assets left in the coal-fired generation FERC accounts.

FERC Account 108 states:

> at the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance. When retirement, costs of removal and salvage are entered originally in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder.

In the future and through the completion of all coal-fired generation closure costs, all coal-fired generation retirement activity is planned to be recorded to the related coal-fired generation FERC accounts as a debit to FERC Account 108. This practice will remain in effect as long as a coal-fired generation assets remain in service.

At the point in which the final coal-fired generation assets are retired, the net book value of those final assets will be reclassified to a regulatory asset as described in Cause No. 45159. The effect of this movement will leave a residual FERC Account 108 balance representing either collections of cost of removal in excess of retirement activity or a balance representing retirement spend in excess of cost of removal collected. FERC Account 108 balances are normally associated with a corresponding FERC Plant-in-Service account. As there will no longer be a FERC Plant-in-Service account for coal-fired generation, NIPSCO proposes to reclassify the balance to a regulatory liability in the instance demolition and remediation activities remain or a regulatory asset if demolition and remediation activities exceed cost of removal collected.

NIPSCO will continue to collect cost of removal until an ensuing rate case through the approved depreciation rates, and NIPSCO will

> continue to record demolition and remediation activities to this new regulatory liability or asset in place of the FERC Account 108. The regulatory liability or asset will be included in a future base rate proceeding and amounts will be passed back or collected from customers. This will maintain the consistency of the mechanism with OUCC Witness Blakley's stated goal not to deny NIPSCO recovery of any return "of" or "on" its investment in the coal fired generating stations.

Pet. Ex. 3 at 117-119. Further, the Settling Parties agreed to the creation of regulatory liabilities or assets, as applicable to be included in future rates upon the elimination of the appropriate FERC Plant-in-Service Account, while retaining the right of others to make any challenge permitted by law, including the prudence and reasonableness of the cost.

E. Pro Forma Net Operating Income at Present Rates. The Settlement Agreement resolved the following issues concerning pro forma net operating income at present rates:

(a) Revenues. The Settling Parties accepted approximately 50% of the proposed increase in the residential sales forecast proposed by the Industrial Group, which increases revenues by approximately $2 Million.

(b) Labor. Based upon Mr. Gorman's testimony, the Settling Parties agreed to reduce NIPSCO's proposed adjustment for vacant positions by $2.2 Million.

(c) Pension and OPEB Expense. The Settling Parties agreed to accept NIPSCO's proposed adjustment to increase Pension and OPEB Expense by a combined $15.2 Million based upon the most recent actuarial report available prior to the filing of NIPSCO's case-in-chief. NIPSCO agreed to withdraw its request for a pension/OPEB balancing account.

(d) Vegetation Management. The Settling Parties agreed to reduce NIPSCO's proposed vegetation management expense by $5.8 Million, resulting in a total annual vegetation management expense of $25.1 Million. This is NIPSCO's 2022 budgeted vegetation management expense, adjusted by a 5.20% inflation escalator, making the agreement consistent with the proposal by the OUCC and Industrial Group that set Petitioner's base vegetation management budget at NIPSCO's budgeted 2022 expense.

(e) Fuel Costs. The Settling Parties agreed the base cost of fuel proposed in NIPSCO's case-in-chief would be reduced by $25 Million. NIPSCO Witness Taylor testified that the base cost of fuel utilized for purposes of the Settlement is $367,509,634. This corresponds to an approximate $0.033674/kWh on average (or

$33.67 per mill). OUCC Witness Eckert explained that NIPSCO initially requested a base cost of fuel of $35.964 mills per kWh and the Settling Parties agreed to approximately $33.67 mills per kWh. The reduction in the base cost of fuel reflects reduced market prices of natural gas and purchased power.

(f) Schahfer Fire. The Settling Parties agreed a $1.06 Million annual O&M reduction will be made in this case and any subsequent case through June 30, 2034, to resolve all known and/or disclosed issues related to the fire at Schahfer in July 2020. NIPSCO warranted that it was "unaware of any facts that would support a claim" for disallowance of costs or expenses related to the fire not already disclosed to the Commission. This portion of the Settlement Agreement also preserves the other Settling Parties' rights to pursue further adjustments should previously unknown or undisclosed facts support additional disallowances.

(g) Other O&M. The Settling Parties agreed to further reduce O&M by a total of $4.7 Million. This reduction addresses other issues raised by the parties related to pro forma results of operations at present rates.

F. Environmental Cost Tracker. The Settlement provides that NIPSCO's proposed VCT shall be renamed the ECT and approved, using the filing methodology and frequency described by NIPSCO Witness Blissmer, except as modified by the Settlement. The only costs to be recovered through the ECT are those associated with NOx emissions allowances and variable chemical costs (estimated to be a total of $30 Million per year). The ECT will be allocated among rate classes based on energy. For Rate 526, the Settling Parties agreed to a demand-based rate design, with recovery through demand charges. NIPSCO also agreed to make good faith efforts to monetize unused NOx allowances, with 100% of benefits passed to NIPSCO customers through the ECT; to re-evaluate procurement practices; and to report on monetization in each ECT tracker filing. Rather than being tracked, the costs associated with generation maintenance and outages originally proposed by NIPSCO as part of the VCT will instead remain embedded in base rates in the amount estimated by NIPSCO in its case-in-chief of approximately $72 Million. For the costs that will be included in base rates, the Settlement provides that these costs will be allocated in the same manner that they were allocated in Cause No. 45159 to maintain the "status quo" regarding allocation, which includes both a demand- and energy-based allocation component. NIPSCO Witness Whitehead and Industrial Group Witness Dauphinais both explained that the costs moving from the originally proposed VCT back into base rates would be allocated to customers on the same basis as they currently are, pursuant to the 45159 Order, which has both an energy- and demand-based component. Pet. Ex. 2-S at 10 and IG Ex. 7 at 8.

The ECT filing methodology and frequency was described by NIPSCO Witness Blissmer. The filing will be semi-annual and based upon actual historical costs. The charge will be calculated on a per kWh basis (except for Rate 526 per the Settlement Agreement). Actual costs recovered through the rider would be deferred commencing with the approval of Step 1 rates until they are recovered through the rider. The first filing is expected to be in March 2024, seeking to recover costs incurred from the effective date of Step 1 rates through December 31, 2023. This first rider would be expected to take effect in July 2024. The second filing would then be in September 2024, recovering actual costs incurred from January 1, 2024 through June 30, 2024. The filings would follow semiannually in March and September thereafter. Pet. Ex. 4 at 33-34.

As proposed in NIPSCO's case-in-chief, NIPSCO will not implement cost recovery under the ECT immediately upon approval. Instead, NIPSCO will begin to incur costs in September 2023 but will defer recovery into 2024, which will result in rate implementation in the summer of 2024, thereby spreading out the rate increase over three (rather than two) steps—September 1, 2023; March 1, 2024; and approximately July 1, 2024. Ms. Whitehead sponsored Attachment 2-S-A, the proposed form of tariff for the ECT, along with Appendix K, which replaces the proposed forms she sponsored in her direct testimony for the VCT. Pet. Ex. 2-S at 10-11.

NIPSCO Witness Taylor presented the Proposed Rate Class Revenue Increase with ECT. Pet. Ex. 19-S, Table 2 at 10.

Industrial Group Witness Dauphinais testified that the settled terms regarding the new ECT are reasonable. He said the greatly reduced scope of the new tracker addresses the concerns he raised in his direct testimony about the relative merits of moving the proposed costs from base rates into a tracker. For the costs that are remaining in base rates, the agreement to retain the same cost allocation basis that was used in Cause No. 45159 preserves the status quo, consistent with the cost of service study approved by the Commission in that case. IG Ex. 7 at 8. Mr. Dauphinais addressed this issue in his direct testimony, arguing that most of the cost types that NIPSCO was proposing to recover in the VCT (now ECT) were previously recovered, and still should be recovered, on a demand basis. IG Ex. 2 at 24-25.

Walmart Witness Kronauer also testified that he supported the ECT Rate 526 cost allocation set forth in the Settlement Agreement. He explained that Walmart agrees with Mr. Dauphinais' assessment that because most of the cost types recovered from the ECT are fixed costs, they are more appropriately recovered through demand charges for Rate 526. Walmart Ex. 2 at 6.

G. Phased Rate Implementation. In addition to the mitigation resulting from the implementation of the ECT, the Settlement provides for the implementation of at least two steps of the rate increase as proposed in NIPSCO's case-in-chief. The Settlement provides that Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023, and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023. NIPSCO will provide all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

The Settlement provides for a similar treatment for Step 2. The Settlement provides that Step 2 rates should be implemented on or about March 1, 2024, and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settlement provides that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023, and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2023. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

The Settlement also provides for possible interim steps between Steps 1 and 2 in the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully placed in service by June 30, 2023, but come into service by December 31, 2023. In rebuttal testimony, Mr. Campbell described that it was possible either or both projects might be delayed beyond Step 1 rates. He explained that, in that event, if a portion of either of the projects is installed, interconnected, and producing energy (i.e., used and useful), NIPSCO will certify that portion as being in service for Step 1. Pet. Ex. 11-R at 26-27. Ms. Shikany testified that an interim step would nevertheless be necessary to mitigate the continued accrual of Post In Service Carrying Charges. Pet. Ex. 3-R at 5-7. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

H. <u>Cost of Service, Rate Design, and Rate 831/531 Modification Settlement</u>. The Settlement is comprehensive in that it resolves the revenue requirement, rate implementation questions, and all cost of service and rate design issues, including the Rate 831/531 Modification Settlement. All Settling Parties have agreed to support or not oppose adoption of the Rate 831/531 Modification Settlement. The Settlement Agreement proposes further enhancements to the Rate 831/531 Modification Settlement by correlating future reductions in Tier 1 load to reductions in the costs of legacy coal assets reflected in NIPSCO's base rates while continuing to move Rate 531 cost allocation closer to the cost of service. Also, all parties not signatories to the Rate 831/531

Modification Settlement retain all rights in future proceedings to take any position with respect to cost of service and Rate 531 issues.

The Settlement acknowledges that, as presented in NIPSCO's case-in-chief and rebuttal, residential rates under Rate 511 are being subsidized by several other rate classes, including, but not limited to, Rate 520 through Rate 533. For this reason, the Settlement Agreement proposes to mitigate a portion of this subsidy. The reduction in annual revenue (i.e., the approximately $103.2 Million of annual revenue below NIPSCO's as-filed case) will be allocated: first, to maintain Rate 531 at cost of service based on 180 MW of allocated demand as reflected in the Rate 831/531 Modification Settlement; second, 25% of the remaining amount for subsidy reduction; and third, the 75% remaining amount allocated on an across-the-board basis. Because Rate 831/531 is being brought to parity at 180 MW of allocated demand, it will not receive either a reduction to reduce subsidies (the 25% portion) or a reduction on an across-the-board basis (the 75% portion). Rate 811 rates will participate in the across-the-board reduction (the 75% portion). The Settling Parties agreed that rates will be designed so that no rate class that is currently being subsidized will move to subsidizing other rates, and no rate that is currently subsidizing other rate classes will move to being subsidized by other rates. Regarding Rate 526, considering that significant amounts of demand costs are being recovered through the energy charge, the Settling Parties agreed the revenue reduction as a result of the Settlement that is allocated to Rate 526 will be used to reduce the energy charge until all energy and demand components of Rate 526 match NIPSCO's energy/demand cost of service levels.

OUCC Witness Boerger testified that the three-step approach represents a fair approach to allocating the revenue reduction achieved as part of this Settlement Agreement. He said the significant reduction in overall revenue achieved in the Settlement allows for a higher share of the reduction to be allocated to customer classes paying rates above parity, while also providing for significant reductions in NIPSCO's proposed rates for all customer classes, including residential customers, and allowing the terms of the Rate 831/531 Modification Settlement to remain in place. For these reasons, the OUCC is satisfied these provisions represent a reasonable resolution of revenue reduction allocation. Pub. Ex. 17 at 2.

Walmart Witness Kronauer testified that he supported the revenue allocation set forth in the Settlement Agreement. He said while the Settling Parties did not adopt the proposal from his direct testimony specifically, the revenue allocation set forth in the Settlement Agreement essentially adopts the proposal in concept. Providing for a subsidy reduction by using 25 percent of the overall reduction in annual revenue (as opposed to Walmart's recommended 50 percent), after establishing Rate 531 at parity, is a reasonable compromise that benefits all classes while moving no class from a subsidized position to a subsidizing position or vice versa. Walmart Ex. 2 at 3-4. Settlement witnesses for NIPSCO, the Industrial Group, and NLMK provided further support for the reasonableness of the cost of service and subsidy mitigation provisions. Pet. Ex. 19-S at 2-5; IG Ex. 7 at 2-3, 6-7; NLMK Ex. 2 at 2-3.

NIPSCO Witness Taylor presented the settlement revenue apportionment and class rate increases in Attachment 19-S-A. Pet. Ex. 19-S. Table 1 in his settlement testimony shows the mitigation of interclass subsidies from NIPSCO's case-in-chief proposal to the Settlement. *Id.* at 5. He also presented Attachment 19-S-B which shows detailed calculations for each rate component of each Rate Schedule, as well as how the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 19-S-B provides a presentation of the transition of revenues at current rates and existing 800 series rate classes to the proposed revenues at the 500 series rate classes. Mr. Taylor also presented Attachment 19-S-D as a new version of Attachment 19-H from his direct testimony which provides the updated tracker allocators that result from the Settlement changes to cost of service and revenue mitigation.

The Settlement Agreement also provides that the Industrial Group will not pursue its proposal for voltage-adjusted FAC and revised allocation for renewable resources in this case. All Settling Parties retain all rights in future proceedings to litigate these issues.

With regard to cost of service methodology, the Settlement Agreement adopts the terms of the Rate 831/531 Modification Settlement, which provides for use of 4 CP for production assets in this case. The Settlement Agreement provides that in its next electric base rate case, NIPSCO will prepare distinct 4 CP and 12 CP cost of service analyses for purposes of allocating production-related demand costs and make each analysis available to all parties in the case. NIPSCO retains the right to determine which cost of service analysis to propose in its case-in-chief, and all other parties will have the right to take any position with regard to cost of service in that case.

The Settling Parties agreed to support or not oppose adoption of the Rate 831/531 Modification Settlement, including the terms relating to the firm service commitments of customers in the class. The current Rate 831 customers agreed to enter into new contracts for an aggregate 170 MW of firm demand under Tier 1 of Rate 531, thereby foregoing the opportunity to reduce firm commitments more substantially, with costs being allocated to the class based on 180 MW. The Settlement Agreement recognizes that further reductions in Tier 1 commitments likely would occur in the future. The Settling Parties agreed to continue to narrow the differential between Rate 531 allocated demand and actual contract demand, but in no event shall that narrowing be accomplished by requiring a Rate 531 customer to increase its Tier 1 demand involuntarily. In support of the Rate 831/531 Modification Settlement, both NIPSCO and the Industrial Group presented testimony explaining the significance of stability in firm load for large industrial customers for purposes of capacity planning by NIPSCO during the transition from legacy coal-fired plants to a portfolio of replacement capacity, and the diminishing role of firm industrial demand as the costs of legacy assets are reduced and removed from rates. Pet. Ex. 2 at 42-48; IG Ex. 2 at 13-19.

The Settlement Agreement provides further detail as to how future reductions to Tier 1 load and cost allocations to Rate 531 as contemplated in the Rate 831/531 Modification Settlement will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates. Under that process:

(a) the relevant comparison is between end of test year in the prior rate case and end of test year in a subsequent rate case;

(b) the measure of costs for legacy coal assets includes capital balances for coal assets, as well as fixed O&M, coal inventory, and other base rate inclusions;

(c) the starting point is the proposed Rate 531 tariff terms and conditions, 180 MW of allocated Rate 531 class demand, and 170 MW of aggregate contract demand. The eventual end point, based on the current composition of the class, is 70 MW of both Tier 1 class demand and actual contract demand, with future proportional adjustments reducing the starting 110 MW differential between the class demand and the end point;

(d) successive future adjustments will involve both reductions in Tier 1 class allocations and contract demand commitments to progressively narrow the spread between allocated demand and actual contract demand for the class; and

(e) the methodology assumes existing class composition throughout legacy coal asset recovery period, subject to an agreed process to address any material changes in circumstance.

Nothing in the Settlement Agreement obligates an existing Rate 831 class member to increase its Tier 1 contract demand commitments in the future. In the event of any material change of circumstances affecting the composition of the class or the class load, the signatories to the Rate 831/531 Modification Settlement and OUCC agree to meet and confer, with the following clarifications: (a) no class member is prohibited from exiting the rate upon expiration of the contractual term; (b) existing tariff provisions on modifying commitments in the event of a facility closure remain in force; (c) in the event a class member exits the rate, the allocated demand and total contracted demand for the class will be reduced correspondingly provided that the exiting customer is migrating to another rate schedule with a like firm demand or the exit from Rate 531 is attributable to a facility closure or material reduction in load; (d) in the event that a class member increases Tier 1 load then other class members not at tariff minimum may decrease Tier 1 commitments correspondingly to maintain class load at agreed levels; (e) in the event a new customer joins the rate class then existing customers with firm demand above the tariff minimum will be permitted to reduce Tier 1 commitments so long as the class load is maintained at the agreed levels; and (f) recognizing that not all contingencies can be anticipated and addressed in advance, any signatory to the Rate 831/531 Modification Settlement or the OUCC may initiate discussions in the event of a material change of circumstances and, absent agreement, may submit the issue for resolution by the Commission.

Dr. Boerger explained the terms of this subsection prevent proportional reductions in Tier 1 cost responsibility greater than the proportional reduction in costs of legacy coal assets. Noting there are several specific implementation provisions and caveats found in this language, he said the nucleus of this section reflects agreement that Rate 831/531 customers will continue to help fund the costs of NIPSCO's legacy coal assets, until such costs are no longer found in NIPSCO's base rates. He testified while the OUCC sought in its direct testimony to obtain a higher level of ongoing funding from Rate 831/531 customers for NIPSCO's legacy coal assets, the provisions in this subsection represent a reasonable compromise of positions and will provide a greater degree of certainty that the OUCC expects will benefit all customer classes. He explained he was happy to see provisions in Section B.7(g) referencing commitments to "meet and confer" in the event of material changes in circumstance and "initiate discussions," recognizing that "not all contingencies can be anticipated." Given the unusual nature of Rate 831/531, he expects such commitments to communication and collaborative work will be helpful moving forward. Pub. Ex. 17 at 2-3.

The provisions relating to Rate 531 were further supported by settlement testimony from current Rate 831 customers. Mr. Dauphinais testified the terms largely preserve the status quo, with modest reductions in Tier 1 commitments and a closer alignment between cost-allocation demand and actual demand. He stated the treatment of future Tier 1 adjustments is reasonable and beneficial to NIPSCO, other rate classes, and Rate 531 customers. IG Ex. 7 at 3-6. Mr. Radigan testified that these provisions collectively aim to provide predictability to all customers and Rate 531 participants today and in future cases and explained that NLMK considers this is a fair and reasonably balanced approach to highly inter-related economic competitiveness and cost allocation concerns presented in this Cause. NLMK Ex. 2 at 5. Mr. Riberich testified that the Settlement Agreement benefits NIPSCO's customers. He explained as to U.S. Steel's specific interests, the fundamental structure of Rate 531 remains unchanged and fully recovers the settled revenue requirement associated with the class. Customer eligibility for the rate, how the service tiers will work, and how Large Industrial Customers will contribute to NIPSCO's revenue requirement have not changed from what NIPSCO originally proposed in its Petition in this Cause. He said the Large Industrial Customers proactively agreed to commit to a set amount of Tier 1 Firm Contract Demand elections and a calculated demand rate that fully recovers the required settled revenue requirement for Rate 531. Without such a commitment, the settled revenue requirement as it relates to Rate 531 is meaningless, because customers cannot be forced to take a set level of firm demand. U.S. Steel Ex. 2 at 3-4.

The Settlement also addresses several rate design issues unrelated to Rate 531. The Settlement adopts the customer charges proposed by NIPSCO, except NIPSCO's existing monthly charge for Rate 511 shall be increased to $14.00 and the existing monthly charge for Rate 521 shall be increased to $32.50. Witnesses explained that through compromise, the Settling Parties agreed to increase the monthly residential customer charge by $0.50 to $14.00, which was NIPSCO's monthly residential customer charge prior to the 45159 Order. In addition, the Settling Parties agreed to increase the small commercial (Rate 521) monthly customer charge by $1.00 to $32.50. Pub. Ex. 16 at 13; Pet. Ex. 2-S at 12; Pet. Ex. 19-S at 7.

In response to CAC testimony, NIPSCO agreed to collect data on residential customer housing types to identify multi-family customers and analyze cost differentials between single- and multi-family residential customers. NIPSCO will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, NIPSCO will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested stakeholder the results of its analysis.

As part of the Settlement, and to address issues raised by the Industrial Group in its direct testimony, NIPSCO agreed that as part of preparing the cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to this rate or the creation of another rate for current customers in Rate 532 is appropriate.[15] This review will include a review of the appropriate minimum demand level for participation in Rate 532 and demand blocks and demand and energy charges. NIPSCO will make this information available to any member of this rate class and/or their

[15] NIPSCO made similar commitments to study operational and usage characteristics of each of the four RV Group members to determine if a new or adjusted rate schedule is appropriate prior to NIPSCO filing its next electric base rate case, as reflected in Joint Exhibit 1, Addendum B, paragraph 5.

consultants who request such information.[16] Finally, the Settlement provides that the percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511.

I. Low Income Program. The Settlement provides that NIPSCO will withdraw its proposed Low Income Program. However, under the Settlement, NIPSCO retains the right to seek approval of a low income program in the future. In recognition of concerns expressed by the OUCC and CAC, NIPSCO agreed to contribute below the line (i.e., not to be recovered through rates) a total of $400,000 to Indiana Community Action Association. These contributions will be made in $100,000 increments in calendar years 2024, 2025, 2026, and 2027. Ms. Whitehead explained that NIPSCO made this decision primarily based on disagreement among the parties as to whether a non-by-passable, opt-in, or opt-out program design was appropriate. She said that NIPSCO's annual contributions to the Indiana Community Action Association are intended to enable many more low-income residents to get necessary health and safety work completed on their homes, which is a prerequisite for qualifying for home weatherization. Pet. Ex. 2-S at 15-16; see also Pub. Ex. 16 at 14. On cross-examination, Ms. Becker explained that these funds will be used to improve conditions at homes that would otherwise be eligible for federal weatherization dollars—improvements such as repairing a leaking roof. As such, she testified that NIPSCO's contribution would have a material and positive effect on providing access to this federal program. Tr. at A-97 to -98.

J. Other Relief Requested by NIPSCO. Paragraph B.14. of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed by NIPSCO's case-in-chief, as modified in its rebuttal testimony. This type of provision is common in Settlement Agreements before the Commission and reasonably identifies the starting point for purposes of the ratemaking and accounting authority being granted. The Commission notes that Petitioner clarified on rebuttal that its requested relief does not include approval of a tax rate change rider. Instead, Petitioner's request is for deferred accounting authority and that it be permitted to request approval of a rider outside of a general rate case, at which time all interested parties would retain the right to oppose such approval (should it be requested) on any grounds other than that it should not be approved outside of a general rate case. Petitioner's Ex. 3-R at 33. In general, the relief sought by NIPSCO is summarized in Paragraph 5 of this Order.

K. Typical Bill Comparison. Ms. Whitehead presented Attachment 2-S-B, which showed the estimated impact on the average residential customer's monthly electric bill and how that compares to the estimated impact on customers in NIPSCO's case-in-chief. She said that for a typical residential customer using 668 kWh, the Step 2 rate implementation in March of 2024 plus implementation of the ECT in July of 2024 results in a total increase of 10.3%. This compares to an estimated 11.3% increase following Step 2 rate implementation and 16.5% increase following VCT implementation under NIPSCO's case-in-chief. She testified that NIPSCO believes the Settlement and resulting impact on all customers represents a reasonable, fair resolution to this case. Pet. Ex. 2-S at 21-22.

[16] NIPSCO made similar commitments to provide advance rate characteristic and cost allocation information available to the RV Group prior to NIPSCO filing its next electric base rate case, as reflected in Joint Exhibit 1, Addendum B, paragraph 6.

Mr. Taylor presented the typical bill impacts for residential customers on Attachment 19-S-C, which contains two bill impact analyses: (1) with the base rate increase and the inclusion of the ECT, and (2) the base rate increase, without the ECT. Pet. Ex. 19-S at 10.

L. Addenda to the Settlement Agreement. Ms. Whitehead explained that Addendum A contains separate terms between NIPSCO and IMUG, which were reached to address IMUG's concerns and allowed them to not oppose the Settlement. Likewise, Addendum B contains separate terms and commitments by NIPSCO to and with the RV Group, which were reached to address the RV Group's concerns and allowed the RV Group to sign the Settlement. Neither of the addenda have a direct base rate impact, but do, in part, respond to and address service-related concerns raised by both parties and were reasonable ways to resolve concerns, promote more effective and efficient use of electricity generally, and allow these parties to either not oppose or to sign on to the Settlement. Because there is no direct base rate impact, NIPSCO does not believe the Commission needs to take any action on the addenda. However, NIPSCO included them as addenda to the Settlement to ensure the Commission was aware of these terms and to memorialize NIPSCO's commitments to these parties and the basis for the positions to not oppose and to sign on to the Settlement. Pet. Ex. 2-S at 16-17.

Mr. Sommer testified in support of Addendum A and stated IMUG does not oppose the remainder of the Settlement Agreement. He said through negotiation, compromise, and settlement, Addendum A largely addresses the concerns and recommendations from his direct testimony. He summarized each of the sections of Addendum A, including limiting the Rate 550 increase,[17] IMUG member energy efficiency audits, sharing LED conversion expertise, and a joint effort to improve NIPSCO record-keeping for NIPSCO street light maintenance. He testified municipalities are unique from other types of NIPSCO customers in that their need for affordable electric service is critical to their ability to fulfill their public service role. He said through the provision of vital public services, municipalities are materially responsible for the wellbeing of area residents, workers, and businesses. They serve the public without any profit motivation and provide many services essential to public safety and the economic wellbeing of those who live in, work in, or visit their areas, including street lighting. He testified that because municipalities are financial closed loop public service entities, dollars saved on electric costs could be used to maintain and improve vital public services. Mr. Sommer stated in all, Addendum A promotes efficiency, public service, public safety, and economic development; yields substantial benefits to municipalities, their residents, NIPSCO and its customer; and helps avoid protracted litigation, costs and uncertainty. IMUG Ex. 2 at 2-6

RV Witness Burke discussed both service improvement commitments and the TDSIC portion of Addendum B and explained why they are reasonable and appropriate. RV Group Ex. 4-S at 3-4. He explained that not only is NIPSCO making a written commitment, including a targeted dollar amount for the RV Group, but the language also: (1) recognizes that these projects and the related TDSIC facilities can be used to serve other NIPSCO customers; and (2) places an obligation on the RV Group member applying for such a TDSIC project that the project:

[17] The commitment regarding Rate 550 is also included in Section 7(l) of the Settlement Agreement and provides: "The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511."

> …result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. (Addendum B, Page 2, Para. 9).

Id. at 5. Mr. Burke stated these obligations are specific and beyond what is required under the TDSIC statute but designed to encourage actions by the RV Group to retain or increase energy and/or employment levels and make capital investments in NIPSCO's service territory here in the State. He testified that the TDSIC section is not intended to be a preapproval request of the Fund or any of the projects discussed and anticipated but does commit both NIPSCO and the RV Group members as provided in Addendum B. *Id*. at 6.

M. Public Interest. Ms. Whitehead testified that all the provisions of the Settlement are interrelated, and the Settlement represents a diligent effort by all Settling Parties to reach a comprehensive result. Citing to 170 IAC 1-1.1-17, Ms. Whitehead described the Commission's policy regarding settlement, which she said is consistent with the general public policy favoring settlement. Pet. Ex. 2-S at 18.

The Settlement Agreement provides that if following its examination, the Commission finds it to be in the public interest, the Settlement should be approved in its entirety and without change or conditions unacceptable to any Settling Party. Ms. Whitehead testified that the Settling Parties' ability to negotiate a settlement in this proceeding representing various customer segments and diverse interests is strong evidence that the Settlement is in the public interest. She testified the Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement, cost allocation, and other significant issues. Moreover, the Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost. She said NIPSCO and the other Settling Parties invested significant time and effort to reach a "global" settlement of this kind. In so doing, the Settling Parties explicitly agreed that the Settlement accounts for the overall level of risk presented to NIPSCO by the Settlement. Per Ms. Whitehead, NIPSCO believes this is important because it only agreed to the terms based on the Settlement as a whole, and it expects to receive the full value of and benefits from the Settlement. Pet. Ex. 2-S at 19-21.

Mr. Eckert testified the Settlement Agreement balances the interests of NIPSCO and ratepayers. He said the Settlement Agreement is a product of intense negotiations, with each party offering compromise to challenging issues. He said that while the Settlement Agreement represents a balance of all interests, given the number of benefits provided to ratepayers as outlined in the Settlement Agreement and described in his settlement testimony, the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, supported by evidence, and should be approved. Thus, the OUCC recommends the Commission find the Settlement Agreement to be in the public interest and approve it in its entirety. Pub. Ex. 16 at 2, 15.

On behalf of the Industrial Group, both Mr. Gorman and Mr. Dauphinais testified that in addition to individual components of the agreement, the Settlement as a whole provided a fair and reasonable resolution to the issues raised in the proceeding. Mr. Dauphinais emphasized that the Settlement was negotiated in good faith by the parties, all of whom were represented by counsel and had the benefits of the parties' respective evidentiary submissions and extensive discovery. Mr. Gorman likewise testified that the Settlement was the result of arm's length negotiations conducted in good faith by parties with a range of diverse interests, which were sometimes complementary and sometimes contradictory. He explained that despite the complexity of the issues, the parties were able to achieve consensus on the Settlement, which he believes represents a reasonable resolution to the case and appropriately balances the various interests of the parties in a manner consistent with sound ratemaking principles. IG Ex. 6 at 6 and IG Ex. 7 at 9.

RV Group Witness Burke testified that he supported the Settlement Agreement, including Addendum B, as being in the public interest and recommended that it be approved without modification. RV Group Ex. 4-S at 6.

Walmart Witness Kronauer explained why he believes the Settlement Agreement is consistent with the public interest. He stated the Settlement represents significant compromise between the parties on the complex issues in this case that will produce an opportunity for NIPSCO to earn sufficient revenues to provide adequate service to its customers at a fair return while also protecting those customers, and the Indiana public, from unreasonable rate increases and impacts. Walmart Ex. 2 at 6-7.

Mr. Radigan testified that NLMK fully supports Commission adoption of the Settlement Agreement in its entirety. NLMK Ex. 2 at 2.

U.S. Steel Witness Riberich testified that approval of the Settlement Agreement is consistent with the public interest because the Settlement represents a comprehensive resolution of all the issues in this proceeding by the Settling Parties, including NIPSCO's revenue requirement, cost of service, and rate design. He said the Settlement Agreement provides NIPSCO with an opportunity to earn sufficient revenues to provide reasonably adequate service and a fair return on its investment. It also balances the interests of the utility's current and future customers in receiving reasonable service at a fair cost. U.S. Steel Ex. 2 at 5.

8. Opposition to Settlement Agreement. Mr. O'Connell testified as to MIUG's opposition to the Settlement Agreement. MIUG Ex. 3. He explained what he considered to be arbitrary barriers in the proposed Rates 532 and 533 because they were created without a clear methodology and are primarily the result of past NIPSCO rate case settlements. He said these arbitrary barriers directly cause certain transmission customers to pay significant premiums on their electric services by forcing them on to the proposed Rate 526 services. He said the proposed Rate 526 and current Rate 826 allocates distribution system charges to at least two transmission customers who are not connected to NIPSCO's distribution system; whereas, the proposed Rates 531, 532 and 533 only allocate transmission and sub-transmission charges to similarly situated transmission customers. He explained, using cost causation principles, NIPSCO should not allocate its distribution system costs to any transmission-only customers, as these customers do not benefit from NIPSCO's distribution system, nor were they the direct or proximate cause for the development of the distribution system. He also said, under the proposed Rate 526, a hypothetical transmission customer with a peak demand of less than 10,000 kW will be allocated significant distribution service charges, while a similarly situated customer on the proposed Rates 531, 532, or 533 who happens to have a peak demand of over 10,000 kW will pay no such distribution service charges.

Mr. O'Connell recommended the Commission modify NIPSCO's proposed Rates 532 and 533 for transmission or subtransmission by removing, or significantly reducing, the minimum peak demand requirement to 2,000 kW or a value that is supported by a reasonable and just calculation methodology, to allow more transmission and subtransmission customers access to these rates and to better align with the principles of cost causation. He suggested NIPSCO's proposed Rates 532 and 533 be modified by removing the requirement for customers, at their own expense, to furnish, supply, install and maintain, beginning at the point of delivery, all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the Premise of the Customer. MIUG Ex. 3 at 3, 9.

He also recommended NIPSCO reincorporate the former Rider 775 and offer it to all Rate 532 and 533 customers. He testified adding this Rider would reduce the risk of NIPSCO procuring excess generation that could potentially be stranded in the future if those Rider customers chose to self-generate or otherwise leave the NIPSCO system. He noted multiple MIUG members recently expressed interest in self-generation, and he believes other Transmission customers will pursue similar options due to increasing rates, unfair rates compared to slightly larger competitors, and the continued misallocation of distribution system capital costs to Transmission customers.

Mr. O'Connell filed separate opposition testimony to Rate 531 and Rider 577. He identified what he considers to be arbitrary or discriminatory barriers in NIPSCO's proposed Rate 531 as related to FERC Order No. 888. He discussed FERC jurisdiction, stating his objective is to clarify the regulatory consequences of Rate 831/531 as it is designed to arbitrarily block Qualified Customers from accessing Tier 2 and Tier 3 of this rate. MIUG Ex. 2 at 3, 10-23. He recommended expanding the scope of customers eligible for Rate 531 to include "qualified customers," which he defined as any customer with at least 1 kW of demand. *Id.* at 9. Mr. O'Connell provided additional information on how MIUG members are considering reducing load on the NIPSCO system without impacting their industrial production. *Id*. at 5-6. He also discussed why he thinks proposed Rate 531 violates various Indiana statutes. *Id*. at 8-9, 23-28.

Mayor Parry explained Michigan City's opposition to the Settlement Agreement. He expressed concern with the impact of the 10.5% increase to the average electric utility bill for Michigan City residents. He said he did not find that the Settlement Agreement addressed his concerns about affordability and the impact of high commercial electricity rates on his efforts to induce businesses to locate and stay in Michigan City. He explained why he believes that the 9.80% ROE referenced in the Settlement Agreement does not send the right message to NIPSCO management. He also explained why he has not seen any sign that NIPSCO is committed to improving its customer satisfaction ratings. Michigan City Ex. 2.

9. **Settlement Rebuttal.** Responding to Mayor Parry's concerns about affordability, Ms. Whitehead explained the steps NIPSCO took during the preparation of the case to mitigate bill impacts. She said that the Settling Parties further built upon the pre-filing rate increase mitigation steps, which resulted in an additional reduction in revenue requirement of over $103

Million. Ms. Whitehead stated that affordability has been addressed by the Settlement terms, which were negotiated with the consumer parties. NIPSCO estimates that the residential bill increase for an average NIPSCO customer consuming 668 kWh has been reduced from 16.5% (in NIPSCO's case-in-chief) to 10.3% (in the Settlement), which is broken into multiple steps over several months. She further explained the bill increase agreed to as part of the Settlement Agreement also resolves issues related to recovery of demolition costs for Schahfer and Michigan City under Ind. Code ch. 8-1-8.4 totaling approximately $93 Million for which NIPSCO was seeking recovery in other cases. So, not only does the Settlement produce a revenue requirement in this case that is approximately $103 Million less than NIPSCO requested, but the Settlement also eliminates any further need for recovery of the federal mandate costs, which would have been in addition to the outcome of the rate case if not included in the Settlement. Pet. Ex. 2-S-R at 1-5.

In response to Mayor Parry's suggestion that NIPSCO shareholders should participate in the burden of transitioning to renewable generation, Ms. Whitehead explained that what Mayor Parry seeks is inconsistent with all the CPCNs previously issued by the Commission for projects associated with NIPSCO's renewable transition. She said those orders found that the public convenience and necessity requires those projects and that the costs are authorized to be included in NIPSCO's rate base and therefore recovered from customers. *Id*. at 6.

Ms. Whitehead also responded to Mayor Parry's concerns regarding the 9.80% ROE. She said that balancing the interest of all stakeholders, the Settling Parties agreed on the ROE of 9.80%, which was a significant reduction from the ROE supported by NIPSCO's expert witness. NIPSCO and the other Settling Parties invested significant time and effort to reach a "global" settlement of this kind. She stated in so doing, the Settling Parties explicitly agreed that the Settlement accounted for the overall level of risk presented to NIPSCO by the Settlement. She explained why the Commission should not make a reduction to the ROE as it did in Cause No. 45159, noting the difference in circumstances. She said that here, the Settling Parties did not agree to the revenue requirement and leave open the status of Rate 831/531. Instead, the Settlement is comprehensive, and it is the resolution of all issues that is embodied in the agreed upon ROE of 9.80%. Thus, the agreed-to ROE in this case already reflects the Settling Parties' assumptions about any effect on ROE from approval of the 831/531 Modification Settlement. *Id*. at 6-9.

In response to Mayor Parry's concerns regarding customer satisfaction and the ROE, Ms. Whitehead explained again that they were considered in the Settlement. Pointing to her rebuttal testimony, she noted NIPSCO is implementing specific actions to help address the service reliability concerns raised by the RV Group and provided an overview of NIPSCO's efforts to utilize satisfaction measurement surveys to continue to improve residential, business, and major accounts customer satisfaction. She explained that she also provided testimony outlining NIPSCO's improvements in the 2022 J.D. Power Residential Customer overall satisfaction survey for the Midwest region of midsize utilities scoring NIPSCO at 724, which is above the group average of 719 and the highest of the Indiana electric investor-owned utilities in the segment. NIPSCO understands that there are opportunities for improvement for its business customers and believes this and NIPSCO's other customer satisfaction scoring were considered in reaching an overall agreement with the Settling Parties. *Id*. at 10-11.

Finally, Ms. Whitehead testified that NIPSCO is encouraged to hear that the Mayor is supportive of a low income assistance program and encourages the Mayor's continued support of

NIPSCO to offer meaningful bill assistance programs to low income customers. She explained that NIPSCO withdrew its proposed low income the program in this case after not being able to resolve concerns raised by some consumer parties. However, NIPSCO retained the right to seek approval of a low income program in the future and committed to continuing to work with consumer parties to address their concerns and offer meaningful low income solutions in the future. *Id*. at 11-12.

Mr. Campbell responded to the two issues raised by MIUG Witness O'Connell. With respect to Mr. O'Connell's arguments that Rate 531 should be expanded to a larger group of customers, Mr. Campbell explained why NIPSCO disagreed and did not consider such expansion to be in the best interests of its other customers. As an initial matter, he said that the Rate 831/531 Modification Settlement makes no changes to the existing Rate 831 service structure, the operating mechanics, or the eligibility requirements for that structure. He testified that Mr. O'Connell's complaint essentially challenges the ARP that the Commission approved in Cause No. 45159 and not the issues or changes presented in this Cause. Citing to Ind. Code § 8-1-2.5-6, Mr. Campbell testified that the Commission may not order material modifications to the ARP without the agreement of the energy utility. He said a change of the type that Mr. O'Connell seeks is a material modification of the ARP and NIPSCO will not agree to the change in scope of proposed Rate 531 that is being requested by Mr. O'Connell. Pet. Ex. 11-S-R at 4-6, 10-11.

Mr. Campbell explained why Mr. O'Connell's requested modification is inconsistent with the purpose of the ARP. He said the Rate 831/531 customers have agreed to a cost allocation based upon demand that exceeds their contracted Tier 1 demand; whereas what Mr. O'Connell suggests is fundamentally different—to open Rate 531 to every customer with at least one kilowatt of demand. NIPSCO has no idea how many customers might want to utilize such a structure or whether they would be willing to accept cost allocation based upon demand that exceeds the contractual commitments. In any event, he explained, the potential scope of load removed from NIPSCO's system under Mr. O'Connell's proposal could have a catastrophic cost impact for those customers who remain on standard service—including NIPSCO's residential customers. It would also turn the proposed Rate 531 into the exact opposite of what NIPSCO's approved original ARP was intended to accomplish—the preservation of a degree of firm, retail, load to ameliorate the risk of rapidly increasing costs to other customers due to a sudden departure of load from the system. *Id.* 6-9.

Mr. Campbell also explained what would occur if the modification to the ARP was to be rejected because NIPSCO was unwilling to accept the change in scope advocated by Mr. O'Connell. He said this is addressed in Paragraph C.1. of the Rate 831/531 Modification Settlement. He explained the approved ARP under which Rate 831 was implemented will remain in place, the Rate 831 customers will provide their respective Tier 1 demands so that rates can be designed for the compliance filing following issuance of the Order in this proceeding, and negotiations will commence. Those negotiations will not result in opening NIPSCO's industrial service structure to all "qualified customers" as advocated for by Mr. O'Connell, because an expansion on that scale and without certainty as to its impact is unacceptable to NIPSCO. Instead, the existing Rate 831 customers would be required to renegotiate their Tier 1 load commitments—commitments made as part of the Rate 831/531 Modification Settlement, which benefit all customers by assuring there is not a precipitous drop in Tier 1 load but rather a gradual reduction. *Id*. at 9-10.

Mr. Campbell explained that Rate 831 is bundled retail service, and Mr. O'Connell's arguments about FERC jurisdiction are incorrect. He said that even if Mr. O'Connell was correct, Mr. O'Connell's proposed solution to expand the group of eligible customers makes no sense because Rate 531 would continue to suffer the same deficiency. Mr. Campbell also disagreed with Mr. O'Connell's claims that all MIUG customers are "similarly situated" to the Rate 831 customers. He said while the Rate 831 customers have technical expertise in house, Mr. O'Connell admits that is not the case with the MIUG members and some, if not all, would need to consider contracting with a power marketer. But, he said, more importantly, Rate 831 was created to address a specific existing circumstance—a small group of five very large customers who represented approximately 40% of NIPSCO's total load, who had the ability to leave NIPSCO's system to the detriment of remaining customers and who possessed the skillset to participate in Rate 831. He said this is not the case with the MIUG members. *Id*. at 11-13.

Mr. Campbell stated any customer can consider behind-the-meter generation but that does not put that customer in the same class as a Rate 831 customer. He also disagreed with Mr. O'Connell's suggestion that any NIPSCO customer could purchase its energy from the MISO wholesale market through MISO Financial Schedules and stated Attachment A is inapplicable to Mr. O'Connell's proposed scenario. He said for Mr. O'Connell's scenario to work, the entity would need to be registered as a Market Participant, which requires additional FERC approvals. A behind-the-meter generator that is not a Qualified Facility would need to be registered by NIPSCO, acting as the Market Participant, on behalf of the Asset Owner that NIPSCO would register as a Load Modifying Resource. In addition, Mr. O'Connell's Attachment A contains a quote from a MISO presentation about behind the-meter generation that is also a Qualified Facility under the Public Utility Regulatory Policies Act, which is not what Mr. O'Connell's scenario addresses. *Id*. at 13-14.

Regarding Mr. O'Connell's claims that Rate 831 is discriminatory and in violation of Ind. Code § 8-1-2-4, Mr. Campbell noted that Rate 831 is pursuant to a Commission-approved ARP, which establishes alternative regulation notwithstanding any other law. He said, additionally, every rate in NIPSCO's approved Tariff contains eligibility requirements and therefore "discriminates" against customers who are not eligible. The question is whether the limits on eligibility are reasonable and whether the rate has been offered to all customers meeting those eligibility requirements. He explained the thresholds created and approved in the 45159 Order are reasonable because they were tailored to address the issue of concern and the particular characteristics of the Rate 831 customers. *Id*. at 15-16.

Mr. Campbell described Mr. O'Connell's claims regarding Rate 532/533, including his claims that the methodology to arrive at the thresholds in the tariff has not been disclosed. Mr. Campbell noted that NIPSCO proposed no changes to the rate eligibility thresholds in NIPSCO's existing approved Tariff. And, although only the Industrial Group opposed that proposal by proposing a reduction to the Rate 532 minimum contract demand from 15,000 kW to 10,000 kW, the Settlement makes no changes to the thresholds. Rather, as to Rate 532, NIPSCO committed to re-evaluate the contract demand and even the possibility of a new rate. Mr. Campbell stated that the methodology to arrive at these thresholds was provided in discovery to the OUCC and explains the thresholds were established in settlement to describe the customers that wished to migrate to these rates in settlement. *Id*. at 17-18.

Mr. Campbell explained the basis for the requirement that the customer own the equipment needed to transform the energy from transmission voltage. He said that this requirement is needed for the customer to be a transmission customer. A transmission customer takes service at transmission voltage and NIPSCO is not responsible for any of the equipment to transform that energy from transmission voltage to the voltage requirements of a customer. He said if NIPSCO was responsible to transform the voltage to the customer's requirements, it would no longer be "transmission" service because the customer would be receiving distribution service. *Id*. at 19.

Mr. Taylor responded to Mr. O'Connell's opposition to the Settlement Agreement regarding the cost causation and allocation of distribution service charges to Rate 526. He stated that Mr. O'Connell misunderstands NIPSCO's allocated cost of service and rate design for Rate 526. Mr. Taylor said that while the allocated cost of service allocates costs to the entire class, the fact that certain customers do not utilize the primary distribution system and certain customers do not utilize the secondary distribution system is reflected in the rate design for Rate 526 as shown in Attachment 19-S-B of Petitioner's Exhibit No. 19-S. He further explained that for the secondary system demand-related costs, the average of 12 monthly non-coincident peaks at secondary allocation factor excludes the kW demand of customers that do not utilize the secondary distribution system. He said this results in the secondary system demand-related costs for Rate 526 being allocated based on 71,896 kW at secondary voltage level, as opposed to the Rate 526 total 12-nonCP which equals 210,121 kW, or approximately 34% of the total 12-nonCP.

Mr. Taylor explained that customers on Rate 526 can take service on other tariffed rate offerings. He said Rate 526 is a rate offering provided by NIPSCO with a discounted demand charge for customer-specific peak demands that occur during off-peak periods. As such, customers can reduce their demand charges by changing their load shapes to off-peak periods. He said these customers can also elect to take service under Rate 524, which does not provide for a demand discount during off-peak periods. He also explained that a customer on Rate 826 who takes service at either primary or secondary voltages would not be eligible for service under Rates 532 or 533 if the thresholds were reduced as requested by Mr. O'Connell. He said as such, none of the members of MIUG would benefit from Mr. O'Connell's proposal. *Id*. at 6-7

10. <u>Commission Discussion and Findings</u>. At the outset, we acknowledge that NIPSCO is in the midst of a substantial generation transition from coal-fired generation to renewable generation resources. As NIPSCO has undertaken this transition, it has invested significant capital into its generation, transmission, and distribution assets—much of which has been pre-approved by the Commission. These investments are the primary driver of the revenue increase NIPSCO seeks in this case, but they are also necessary for NIPSCO to realize benefits for its customers in the longer term. Those benefits include a more reliable and resilient electrical system for the provision of electricity through a diverse set of resources that considers environmentally sustainable sources of electric generation.

Despite the complexity and number of issues raised in this proceeding, the Settling Parties reached a comprehensive agreement, as reflected in the Settlement Agreement filed in this proceeding. Although it is opposed by two parties, those joining or not opposing the Settlement Agreement and Addenda represent a wide variety of interests and types of customers, including residential, commercial, and industrial customers. A complete copy of the terms and conditions of the Settlement Agreement can be found in Attachment A to this Order (Jt. Ex. 1), while the new depreciation rates are set forth in Attachment B (Pet. Ex. 3-S, Attach. 3-F-S) and the Redacted Rate 831/531 Modification Settlement is attached as Attachment C (Pet. Ex. 2, Confidential Attach. 2-B). These attachments are incorporated into and made a part of this Order by reference.

Settlement is a reasonable means of resolving a controversial proceeding in a manner that is fair and balanced to all concerned. The Settlement Agreement represents the Settling Parties' proposed resolution of the issues in this Cause. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co*., 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal. of Ind., Inc.*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including approval of a settlement must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Public Service Co.*, 582 N.E.2d 330 (Ind. 1991)). The Commission's procedural rules require that the settlement be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreements, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreements are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that such agreements serve the public interest.

The Commission has before it substantial evidence from which to determine the reasonableness of the terms of the Settlement Agreement on all issues, including Petitioner's rate base, methodology to be used in determining Petitioner's rate increase, allocation of the rate increase, rate design, ROE and capital structure, and the other terms of the Settlement Agreement, all of which we find are supported by the evidence and testimony presented. The Settlement Agreement, along with its attachments and the Settling Parties' testimony and exhibits, provide substantive information from which to discern the basis for the components of the increase in NIPSCO's base rates and charges under the Settlement Agreement, and we find the evidence supports that they are reasonable. We also recognize that all but two parties in this proceeding either support or do not oppose the Settlement Agreement, including NIPSCO, the OUCC, Industrial Group, NLMK, U.S. Steel, RV Group, Walmart, CAC, and IMUG. These parties represent varied and competing customer groups and interests, encompassing practically all (if not all) NIPSCO rate classes.

As discussed in Section 7 of this Order, the Settling Parties made numerous compromises to reach an agreement. NIPSCO, in its initial case-in-chief, provided evidence supporting a revenue deficiency of $395 Million, reflective of an overall 25.85% revenue increase. As shown by Paragraph B.1.(a) of the Settlement Agreement, the Settling Parties agree that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders, plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount originally requested by NIPSCO in its case-in-chief. Additionally, the Settlement Agreement also addresses cost recovery of approximately $93 Million related to two pending federal mandate cases, which is in addition to the base rate increase NIPSCO sought in its direct case. Jt. Ex. 1, Para. B.3.(a).

Based on the evidence presented, we decline to make the modifications suggested by Michigan City and MIUG for the reasons set forth below and approve the Settlement Agreement without modification.

A. Disputed Issues. There are essentially three issues that have been raised in opposition to the Settlement: (1) whether the Settlement is reasonable notwithstanding the challenges raised by Michigan City, particularly the stipulated return on equity of 9.80%; (2) whether Rate 531 should be expanded to include all customers with at least 1 kW of demand; and (3) whether the minimum demand thresholds for Rates 532 and 533 should be lowered to 2 MW.

1. Reasonableness of the Settlement Agreement. In opposition to approval of the Settlement Agreement, Michigan City raised several concerns with NIPSCO's rates and services that it alleges were inadequately addressed in the Settlement Agreement, including affordability, NIPSCO's commercial customer satisfaction rankings by J.D. Power, the competitiveness of NIPSCO's rates for economic development purposes, and the sufficiency of the provision for low-income assistance. Michigan City is predominantly of the view that the 9.80% ROE in the Settlement is too high. Based on the evidence presented as discussed further below, we are not persuaded by Michigan City's arguments to reject or modify the Settlement Agreement, which the Settling Parties have sufficiently shown provides a reasonable resolution of the differing positions and disputed issues presented in this complex proceeding.

Michigan City takes issue with the 9.80% ROE agreed to by the Settling Parties, especially because of NIPSCO's customer service ratings. However, the record reflects that this compromise 9.80% ROE is within the range of evidence presented, contemplates the level of business risk to NIPSCO resulting from the terms of the Settlement, and is similar to the ROE that the Commission approved for NIPSCO in its 45159 Order. Mayor Parry's concerns regarding NIPSCO's customer service were not unlike those of the RV Group, who is a party to the Settlement Agreement. In addition, despite attempts by counsel for Michigan City at the hearing to elicit testimony about the Commission's Order in Cause No. 43526, we find that the customer service, reliability, and operational and other management issues supported by the evidence in that cause are not present here. As Ms. Whitehead explained, NIPSCO has made improvements in overall customer satisfaction but is also aware that improvements can be made for its business customers and identified efforts that NIPSCO is making to continue to address customer satisfaction and improve customer service. She further testified that these issues were considered by the Settling Parties in reaching agreement on the 9.80% ROE.

Additionally, in support of the Settlement Agreement, Ms. Whitehead explained that it represents more than a $100 Million decrease from NIPSCO's as-filed revenue requirement. This is in addition to certain mitigation steps that NIPSCO identified it had taken in its case-in-chief, including its proposed change in depreciation methodology. As she further testified, in total, these reductions in expense result in a large decrease in cash flow available to NIPSCO, thereby increasing NIPSCO's need to finance expenses and capital investments. The Settlement Agreement reflects NIPSCO's agreement to these various terms, which, from NIPSCO's point of view, link directly to the ultimate agreement on ROE. NIPSCO, its customers, and the Commission all have an interest in ensuring NIPSCO's financial health, because failure to do so will increase NIPSCO's financing costs, causing an adverse impact on the ability to attract capital investment and on customer rates.

Further, as discussed above, the OUCC and other Settling Parties provided testimony supporting the agreed-upon ROE as reasonable and in the interest of ratepayers as part of the entire settlement package. OUCC Witness Eckert specifically addressed the Settlement Agreement's benefits to affordability through its various reductions in NIPSCO's requested revenue increase. While the agreed ROE of 9.80% is higher than the lowest recommended ROE, it is still within the range of reasonable outcomes presented by the parties and benefits ratepayers by reducing the return on rate base reflected in customers' rates as compared to NIPSCO's case-in-chief proposal.

In Cause No. 45159, the Commission reduced the ROE from the level contained in the Revenue Settlement "in light of the reduced business risk to NIPSCO as a result of the approval of the Rate 831 Settlement." 45195 Order at 162. The circumstances here are markedly different from those in NIPSCO's last rate case. In the 45159 Order, we lowered the parties' stipulated ROE based on the sequencing of two separate settlement agreements—the first one addressing the revenue requirement and the second addressing the approval of the new Rate 831 industrial service structure. After the Revenue Settlement that contained the stipulated ROE was executed, NIPSCO entered into the Rate 831 Settlement and Implementation Agreement with some, but not all, of the parties to the Revenue Settlement. As such, the Revenue Settlement was entered without knowledge of how the Rate 831 proposal would be addressed or resolved. We therefore concluded that the approval of the subsequent Rate 831 Settlement and Implementation Agreement lowered NIPSCO's business risk from what had been assumed by the parties when they stipulated to an ROE in the Revenue Settlement. We explained:

> In considering the Revenue Settling Parties' recommended ROE, we note that the Revenue Settlement was finalized, signed, and filed prior to the Rate 831 Settlement and Implementation Agreement. As such, the fate of NIPSCO's proposed Rate 831 large industrial service structure was still uncertain at that time. Furthermore, at no place in the Revenue Settlement is its approval made explicitly contingent upon approval of Rate 831. The Commission's approval of the Rate 831 Settlement and Implementation Agreement and the new industrial service construct designed in it significantly mitigates the risk of the loss of industrial load to NIPSCO and the associated earnings volatility. Therefore, based on this reduced risk for NIPSCO's shareholders, we find that a decrease in NIPSCO's ROE is warranted.

45159 Order at 162. This is not the situation with which are presented in this case.

To begin with, the ARP implementing NIPSCO's Rate 831 industrial service structure was approved in Cause No. 45159 as part of a settlement that was distinct from the agreement on the revenue requirement. Here, the modifications sought to NIPSCO's ARP were contained in the Rate 831/531 Modification Settlement that was filed with NIPSCO's case-in-chief. Thus, in the Settlement Agreement pending before the Commission in this case, the Settling Parties were aware of the provisions of Rate 831/531 Modification Settlement as they presented their responsive cases and then negotiated the revenue requirement and other issues. Moreover, all the Settling Parties either agreed that the Rate 831/531 Modification Settlement should be approved or agreed not to oppose it. As such, the Settling Parties had the opportunity to fully consider the effect of the Rate 831/531 Modification Settlement on this case and were able to take that agreement's impacts, including NIPSCO's resulting business risk, into consideration, when they agreed to an ROE of 9.80%.

Also, in Cause No. 45159, we indicated that the Rate 831 Settlement and Implementation Agreement "explicitly assigns a revenue requirement to the Rate 831 customers." 45159 Order at 162. We therefore reduced the stipulated ROE to limit the impact on non-Rate 831 customers. In the current case, the Settlement Agreement contains specific language to ensure that all customer classes receive some benefit associated with the reduced revenue requirement, limiting the benefit to Rate 531 to a cost of service-based reduction that reflects the class's production-related demand allocation. Moreover, while the introduction of Rate 831 was an innovation on NIPSCO's then existing interruptible power rider, the proposed changes to the ARP in this case maintain the overall existing structure of Rate 831 and reflect only limited changes to the rate structure. The Rate 831/531 Modification Settlement contains only a modest reduction to both the allocation of production-related demand costs to the class and in intra-class Tier 1 firm contract demand.

As discussed above, the proposed modifications to NIPSCO's ARP are consistent with the overall purpose of Rate 831, which is to retain NIPSCO's at-risk large industrial load and continue those customers' contributions to the cost of legacy production assets during NIPSCO's ongoing generation portfolio transition. Any reduction in the allocation of costs to Rate 831/Rate 531 was to be expected as the legacy costs continue to decline through retirements and increased depreciation of the legacy assets. Any intra-class reduction in Tier 1 firm contract demand was likewise expected as participating customers reduce their Tier 1 commitments in reaction to decreasing allocation of production-related costs to the class. Again, the Settling Parties in this case were afforded an opportunity to consider the impact of the Rate 831/531 Modification Settlement, including the reduction in production-related demand to the class, during settlement negotiations.

Accordingly, the Commission finds that when the Settlement Agreement is considered in its entirety, the agreed upon ROE balances the consumer parties' interests and concerns, including those expressed by Michigan City, with NIPSCO's interest in preserving its financial integrity. We therefore find the stipulated ROE of 9.80% is reasonable.

2. Rates 831/531. MIUG's objections to the Settlement Agreement relate predominantly to the fact that it does not incorporate MIUG's proposal to greatly expand eligibility for Rate 531 on materially revised tariff terms. NIPSCO did not propose any change to the eligibility criteria for Rate 531 and made clear that it did not support the material changes to its ARP being advocated by MIUG. NIPSCO argues that MIUG's proposed restructuring of Rate 531 is inconsistent with the purpose underlying the ARP and does not provide sufficient justification for the Commission to deny approval of the Settlement.

In addition to arguing that Rate 531 is unbundled transmission service and therefore invalid, MIUG also asked for Rate 531 to be expanded to all customers taking at least 1kW of service to allow significantly more customers to participate. MIUG also claimed that Rate 531 allows NIPSCO's retail customers taking service under that rate to access the wholesale market.

First, because Rate 531 maintains the Rate 831 service structure and operating mechanics, we reiterate our findings from the 45159 Order that Rate 831 is a rate for retail service. In that Order we specifically found that, "NIPSCO's proposal requires its largest industrial customers to remain as its retail customers, while at the same time providing more market choices." 45159 Order at 153. Nothing has been presented to change this finding or alter the same conclusion. NIPSCO offered additional evidence confirming Rate 831 as implemented is and remains retail service. As explained by Mr. Campbell, Rate 831 customers are purchasing transmission service at retail and the fact that it is part-and-parcel of the delivery of energy under Rate 831 means it remains a retail transaction, over which FERC would not assert jurisdiction. Also, NIPSCO is at all times the Market Participant in MISO, procuring energy and providing transmission of that energy to the customers. FERC Order No. 888 addressed when its jurisdiction applies to bundled versus unbundled service, stating: "[W]e believe that when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the [Federal Power Act] the [Federal Energy Regulatory] Commission's jurisdiction over sales of electric energy extends only to wholesale sales." Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21540, 21625, 1996 WL 239663 (May 10, 1996). *See also* Pet. Ex. 11-R at 6-8.

NIPSCO's tariff is clear that Rate 531 customers taking transmission service must also take service for energy. There is no opportunity for a customer to take transmission-only service from NIPSCO. MIUG's arguments are, therefore, unfounded.

MIUG also proposed to expand Rate 531 to all customers taking at least 1 kW of service. We note that customer contract demand under Rate 831, and proposed for Rate 531, reflect voluntary commitments by each of the large industrial participants in that class. That is a crucial aspect of both the current rate structure and the slightly modified version proposed in the Rate 831/531 Modification Settlement. MIUG, however, proposes to assign Tier 1 demand levels to rate participants based on ratable contributions to peak load. We consider that proposed approach to be fundamentally at odds with the basis for which NIPSCO's ARP was approved.

In the 45159 Order, when we approved the ARP establishing Rate 831, we emphasized that "it was appropriate and reasonably necessary for NIPSCO to revise its industrial rate structure in order to mitigate the credible and preventable threat of large industrial load loss. The record also demonstrates that it is important to NIPSCO and all of its customers to retain the Rate 831 customers and for them to continue contributing to NIPSCO's fixed production costs." 45159 Order at 157. The NIPSCO system is uniquely situated in that NIPSCO's five largest customers account for 40% of total system load, and NIPSCO was facing serious risk of continuing losses of large industrial load. *Id.* at 151. The Commission recognized that, by stabilizing large industrial load with 5-year contracts, Rate 831 would facilitate a more orderly transition as NIPSCO retires aging coal plants and procures replacement capacity. *Id.* at 155-56. The key terms and conditions of Rate 531 remain materially the same as what we approved in the 45159 Order, and MIUG has not suggested otherwise. Instead, MIUG seeks to relitigate the ARP approval for Rate 831 but has not shown that the previously approved service structure of Rate 831, and specifically its eligibility terms, require material revision over the objection of NIPSCO.

In addition, we find that the modifications sought by MIUG would be inconsistent with the purpose underlying the original ARP approval and the Commission's public interest determinations. In approving the Rate 831 ARP, we found that:

> NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers while addressing its aging generation and navigating a dynamic economic environment. Although the Rate 831 proposal requires NIPSCO's other customer classes to pay higher rates in the near term than they are currently paying today under the existing service structure, the long-term risk is that these large industrial customers will otherwise exercise their options to significantly shift load off NIPSCO's system. When that occurs, costs might reasonably be reallocated to the remaining customer classes. While the OUCC and CAC focused on the fairness of a cost shift within this rate case between Rate 831 and other classes, the record shows that denying Rate 831 now would likely result in even higher costs, which would otherwise have been collected under Rate 831 if these customers further bypass NIPSCO's service. When considering the full range of impacts in play rather than just the near-term cost shift, Rate 831 is a reasonable solution now rather than later. We find that retaining the current service structure would only increase the risk that these customers will exercise their options to self-generate additional power or relocate production to avoid an increasing NIPSCO electric price.
>
> Given that large industrial customers constitute such a significant portion of NIPSCO's retail electric sales, reducing their load would cause precipitous declines in NIPSCO's revenues and operating margins far faster than could be offset by growth in other sectors. In the long run, we find that such load loss would subject remaining customers and customer classes to increased costs above and beyond the near term costs of the Rate 831 Settlement. Conversely, we find that approval of this new service structure will provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time.

45159 Order at 154-55.

No evidence was presented of any material change in circumstances that would alter the findings underlying the approved ARP. Utility rates are routinely applied through distinct schedules for defined rate classes. *See* Ind. Code § 8-1-2-46. NIPSCO's large industrial rates, including those previously applicable to current Rate 831 customers, have long included demand thresholds of 10 MW or more. Based on the evidence presented, the Commission finds that MIUG has not shown that its proposal to expand Rate 531 eligibility to most of NIPSCO's commercial and industrial customers with lower demands would be reasonable, consistent with the public interest, or supported by the statutory criteria for ARP approvals under Ind. Code § 8-1-2.5-5(b).

3. Rates 532 and 533. MIUG also seeks to reduce the minimum demand thresholds for Rates 532 and 533 to 2 MW and to eliminate the requirement that the customer own the equipment necessary to reduce transmission voltage to the individual customer's voltage requirements. MIUG argues that, otherwise, customers served directly from the transmission system would pay costs of the distribution system under NIPSCO's Rate 526. However, as NIPSCO Witness Taylor explained, MIUG's underlying premise is incorrect because Rate 526 is structured so that transportation customers on Rate 526 pay a discounted rate such that costs of the distribution system are excluded from their rates. As to the equipment ownership requirement, we agree with Mr. Campbell that if NIPSCO must own the equipment that is necessary to transform the voltage from transmission voltage to distribution voltage, then that customer is not truly a transmission customer. Accordingly, we find the evidence does not support the existence of an unfair burden or discriminatory barrier in requiring customers on Rates 532 and 533 to maintain their own transmission equipment should they require voltage reduction to meet their own needs.

Additionally, the Settlement contains a term that NIPSCO will study the operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to the rate or the creation of another rate is appropriate. This review will include, but not be limited to, a review of the appropriate minimum demand level for participation, as well as demand blocks and demand and energy charges. Jt. Ex. 1, Para. B.7.(k). We find this adequately addresses any remaining concerns over Rates 532 and 533.

B. <u>Ultimate Findings on Settlement Agreement and Rate 831/531 Modification Settlement</u>. Based on the evidence presented, we find that the Settlement Agreement and the Rate 831/531 Modification Settlement should be approved without modification.

With regard to the Rate 831/531 Modification Settlement, NIPSCO has requested minor modifications to its existing ARP that was originally approved in Cause No. 45159. Ind. Code § 8-1-2.5-6(a)(1) authorizes the Commission to adopt alternative regulatory practices, procedures and mechanisms that are in the public interest and that enhance or maintain the value of NIPSCO's retail energy services or property. Our consideration of the public interest is to be guided by our review of the factors set forth in Ind. Code § 8-1-2.5-5. Specifically, Ind. Code § 8-1-2.5-5(b) states in pertinent part:

> (b) In determining whether the public interest will be served, the commission shall consider the following:
>
> > (1) Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful.
> >
> > (2) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state.
> >
> > (3) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency.

(4) Whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

NIPSCO's proposal, adopted by the Settling Parties, substantially retains the structure and terms of existing Rate 831, with modest modifications to support the Rate 531 contract renewals and address future load adjustments to facilitate effective capacity planning. The same statutory considerations remain applicable to the requested modifications. Based on the evidence presented, we find our conclusions in the 45159 Order on these factors remain applicable, and there has been no basis shown to revisit the Commission's prior determinations.

With respect to the first factor, the Commission found in Cause No. 45159 that NIPSCO's large industrial customers utilize energy intensive processes; those customers have alternatives to substantially reduce or eliminate load from NIPSCO's system through self-generation, production shifts or plant closures; NIPSCO had experienced substantial losses of large industrial load; and Rate 831 addressed those risks with a more competitive rate offering that retained those customers as retail customers while stabilizing large industrial load during a crucial period for capacity planning. 45159 Order at 153. The record confirms the same conditions continue to exist and support the modifications sought in this case.

Regarding the second factor, the Commission previously found in Cause No. 45159 that the ARP establishing Rate 831 will be beneficial to NIPSCO and all its customers because it effectively addressed the serious risk of continued erosion in large industrial load, thereby preventing greater and unmanaged reductions. 45159 Order at 154-55. The Commission concluded that the new service structure would "provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time." *Id.* at 155. The record confirms there is still serious risk of precipitous loss in industrial load, which is appropriately addressed with the modifications at issue, in particular the Rate 531 contract renewals and the agreed process for future load reductions.

In Cause No. 45159, the Commission further found the ARP satisfied the third factor by promoting utility efficiency, particularly facilitating effective capacity planning during the key transition period for NIPSCO's generation resources. *Id.* at 155. The Commission concluded that "Rate 831 reduces the amount of replacement capacity NIPSCO must plan for, provides more reliable load projections for planning purposes, and mitigates the risk of building excess capacity." *Id.* Those considerations remain important, as NIPSCO has implemented the first steps in its resource transition but is continuing to navigate future retirements and replacement capacity. The ARP modifications in this case will provide additional support for capacity planning and utility efficiency, by establishing a clear "glide path" for future Rate 531 load adjustments during the period that legacy coal asset costs are being recovered in base rates.

Finally, the Commission found in Cause No. 45159 that the Rate 831 ARP satisfied the fourth statutory factor, insofar as traditional ratemaking impeded NIPSCO's ability to provide competitive rates for large industrial customers with demonstrated capability to exercise alternatives including self-supply, production shifts, and facility closures. *Id.* at 155-156. The record here confirms the same conditions have continued, and the proposed modifications to the ARP support the function of Rate 531 to retain the class as retail load.

With respect to each of the statutory factors, the Commission finds no reason to depart from the findings in Cause No. 45159, and further finds the modifications proposed by NIPSCO will assist in supporting the purposes of the ARP as identified in Cause No. 45159. The modification to the ARP sought through the Rate 831/531 Modification Settlement resolves uncertainties that could bear negatively on other customers if the agreements with the Rate 831 customers were simply allowed to expire by their terms upon approval of new base rates. The Rate 831/531 Modification Settlement is in the public interest, especially when coupled with the additional guidance provided in the Settlement Agreement. Accordingly, we find the modification to NIPSCO's existing ARP should be approved.

The revenue allocation shall be as set forth in the Settlement Agreement and Petitioner's Exhibit 19-S, Attachment 19-S-A. This revenue allocation is based upon the projected rate base and capital structure; the actual revenue allocation shall be based upon the actual rate base, and capital structure at the time, following the three-step mitigation process set forth in the Settlement Agreement. We find that based upon the projected capital structure and rate base, the rates set forth in Attachment 19-S-B and the tracker allocations set forth in Attachment 19-S-D of Petitioner's Exhibit 19-S, are appropriate and should be approved.

We further find that the depreciation accrual rates set forth in Attachment B hereto should be approved. We also find that the regulatory accounting for cost of removal for NIPSCO's coal-fired generation-related assets described in Petitioner's Exhibit 3 at pages 117-19 should be approved.

The proposed ECT, using the filing methodology and frequency described by NIPSCO Witness Blissmer and summarized herein, should likewise be approved. The costs to be recovered through the ECT are NOx emissions allowances and variable chemical costs, allocated among the classes as set forth in the Settlement Agreement.

As noted, Section B.14. of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed by NIPSCO's case-in-chief, as modified in its rebuttal testimony. This includes all the relief summarized in Paragraph 5 of this Order, which has not otherwise been modified by the Settlement. The Commission finds Section B.14. of the Settlement Agreement to be reasonable and it is approved with the entirety of the Settlement Agreement.

We therefore find that NIPSCO should be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $261,923,892, total base rate revenue of $1,767,260,404, and total net operating income of $402,900,940. This is based upon a projected test year ending net original cost rate base of $5,925,013,822 as follows:

Net Utility Plant	$ 4,321,816,455
RMS Unit 14/15 Retirement	$ 593,022,393
Joint Venture Reg Assets	$ 817,299,925
Reg Assets - Cause 44688 & 45159	$ 23,510,338
Electric 2021-2026 TDSIC Plan Cause #45557	$ 24,558,486
FMCA - Post 45159 & CCR Remediation	$ 545,389
Materials & Supplies	$ 98,989,010
Production Fuel	$ 45,271,825
	$ 5,925,013,822

We further find that a fair return should be authorized based upon this net original cost rate base and a projected weighted average cost of capital of 6.80%, as follows:

	Dollars	Cost %	Weighted Average Cost of Capital %
Common Equity	$4,564,821,051	9.80%	5.06%
Long-Term Debt	$3,233,952,976	4.66%	1.70%
Customer Deposits	$59,541,950	5.63%	0.04%
Deferred Income Taxes	$1,393,665,855	0.00%	0.00%
Post-Retirement Liability	$13,945,116	0.00%	0.00%
Prepaid Pension Asset	$(424,946,780)	0.00%	0.00%
Post-1970 ITC	$640,278	7.67%	0.00%
Totals	**$8,841,620,445**		**6.80%**

The rate increase authorized herein should be implemented in multiple steps as set forth below:

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023 and calculate the Step 1 rates using those certified figures.[18] NIPSCO will provide all parties to this proceeding with its certification. The parties will have 60 days to verify or state any objection to the net plant in service numbers from those that NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant

[18] For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023.

construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on or about March 1, 2024 and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023 and calculate the Step 2 rates using those certified figures.[19] NIPSCO will provide all parties to this proceeding with its certification. The parties will have 60 days to verify or state any objection to the net plant in service numbers from those that NIPSCO certifies. The parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) Additional Interim Phases: In the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully in service by June 30, 2023 (meaning the portion that is not certified as partially in service as described in Mr. Campbell's rebuttal testimony) but come into service on or before December 31, 2023, then an additional interim step will be implemented after Step 1 and before Step 2. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates will take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

The Commission further finds and concludes that the Settlement Agreement and the Rate 831/531 Modification Settlement are reasonable, supported by substantial evidence, and in the public interest. Accordingly, both the Settlement Agreement and Rate 831/531 Modification Settlement are approved.

11. Effect of Settlement Agreement. The parties agree that the Settlement Agreements are not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce their terms; consequently, with regard to future citation of the Settlement Agreements or of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC March 19, 1997).

12. Confidentiality. NIPSCO filed motions for protection and nondisclosure of confidential and proprietary information on October 7, 2022, February 10, 2023, and February 16, 2023. The Industrial Group filed a motion for protection and nondisclosure of confidential and

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[19] For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2023.

proprietary information on January 20, 2023. Each motion was supported by affidavits showing certain documents to be submitted to the Commission contain confidential trade secrets as defined under Ind. Code § 23-2-3-2. Docket Entries were issued on each of these motions finding such information to be entitled to confidential treatment on a preliminarily basis, after which the information was submitted under seal. The Commission finds all such information granted preliminary confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. The Settlement Agreement and the Rate 831/531 Modification Settlement, copies of which are attached to this Order, are approved.

2. The modification to Petitioner's ARP approved in Cause No. 45159 as set forth in the Rate 831/531 Modification Settlement and Settlement Agreement is approved.

3. Petitioner is authorized to increase its rates and charges for electric utility service in multiple steps as described in Finding Paragraph 10.

4. New depreciation rates applicable to NIPSCO's common and electric plant are approved as explained in, and attached to, this Order.

5. Petitioner shall file under this Cause for approval by the Commission's Energy Division the new schedules of rates and charges along with its revised tariff consistent with the Settlement Agreement and the rates and charges approved in this Order.

6. Petitioner shall certify its net plant, original cost rate base, and capital structure at June 30, 2023 (Step I) and December 31, 2023 (Step II) and calculate the resulting rates and charges, which shall be made effective upon filing and approval of the Commission's Energy Division in accordance with the findings herein, subject to being contested and trued-up consistent with the Settlement Agreement.

7. To the extent that either Crossroads Solar or Dunn's Bridge I Solar is not completely in service as of June 30, 2023 but is in service before December 31, 2023, Petitioner is authorized to implement an additional interim phase to its increase, based upon the Phase I capital structure as described in Finding Paragraph 10.B.

8. Petitioner is authorized to file updated factors for its rate adjustment mechanisms in accordance with this Order, and such changes shall be effective simultaneously with approval of NIPSCO's new basic rates.

9. Petitioner is granted deferred accounting authority as described in Finding Paragraph 10.B. This includes, but is not necessarily limited to, deferred accounting for cost of removal at coal-fired generating units following the retirement of the last such unit, for discounts provided for purposes of the Economic Development Rider, and for actual costs incurred for environmental and NOx prior to recovery through the new ECT.

10. Petitioner's proposed form of Electric Service Tariff is approved, consistent with the Settlement Agreement and the Rate 831/531 Modification Settlement and this Order, inclusive of the associated General Rules and Regulations and Standard Contracts.

11. Petitioner is directed to file under this Cause all information required by the Settlement Agreement.

12. The information filed in this Cause pursuant to motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

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

APPROVED: AUG 02 2023

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

Dana Kosco Digitally signed by Dana Kosco
Date: 2023.08.02 10:11:38 -04'00'

Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.	)	CAUSE NO. 45772

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 10th day of March, 2023, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); NIPSCO Industrial Group ("Industrial Group");[1] NLMK Indiana; United States Steel Corporation;[2] Walmart Inc.; RV Industry User's Group ("RV Group");[3] and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"). The Setting Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth below represent a fair and reasonable resolution of the issues in this Cause subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein. The Settling Parties agree that this Agreement resolves all disputes, claims and issues arising from the electric general rate case proceeding currently pending in Cause No. 45772 as among the Settling Parties, including revenue requirement, cost of service, rate design, and cost allocation

1 The Industrial Group is comprised of Accurate Castings and Kingsbury Castings, BP Products North America, Inc., Cargill, Cleveland Cliffs Steel LLC, Enbridge, Linde, Marathon, and USG Corporation.

2 United States Steel Corporation's signature page will be late-filed upon receipt of authorization from its executive management.

3 The RV Industry User's Group is comprised of LCI Industries, Inc.; Patrick Industries, Inc.; Forest River, Inc.; and Keystone RV Company.

issues. The Settling Parties agree that NIPSCO's requested relief in this Cause should be granted except as expressly modified herein.

A. Background

1. NIPSCO's Current Basic Rates and Charges. NIPSCO's current electric basic rates and charges were approved in the Commission's December 4, 2019 Order in Cause No. 45159 (the "45159 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement on Less Than all the Issues resolving revenue requirement and other miscellaneous issues ("45159 Revenue Settlement") between NIPSCO and the majority of the intervenors.[4] The Commission also approved a Stipulation and Settlement Agreement on Rate 831 Implementation (the "Rate 831 Settlement").[5] Those new basic rates and charges went into effect on January 2, 2020 (the first billing cycle for January 2020). The 45159 Order approved, among other items, an increase in NIPSCO's basic rates and charges. The 45159 Order also approved an alternative regulatory plan which implemented a new service structure for certain industrial customer through NIPSCO's new Rate 831.

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4 The 45159 Revenue Settlement was entered into on April 25, 2019, by and between NIPSCO, NIPSCO Industrial Group ("Industrial Group"), NLMK Indiana ("NLMK"), United States Steel Corporation ("US Steel"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Walmart Inc., Northern Indiana Commuter Transportation District, Sierra Club, and the Indiana Office of Utility Consumer Counselor ("OUCC") (collectively the "Revenue Settling Parties"). On May 15, 2019, Indiana Municipal Utility Group joined the 45159 Revenue Settlement.

5 The Rate 831 Settlement was entered into on May 17, 2019, by and between NIPSCO, Industrial Group, NLMK Indiana, and US Steel.

2. NIPSCO's Current Depreciation Accrual Rates: NIPSCO's current common and electric depreciation rates were approved in the Commission's 45159 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings: NIPSCO files a quarterly Fuel Adjustment Clause ("FAC") proceeding in accordance with Ind. Code § 8-1-2-42(d) in Cause No. 38706-FAC- XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs. Historically, NIPSCO has agreed that the OUCC and other interested parties should have thirty-five (35) days to review NIPSCO's FAC filings and NIPSCO has agreed to continue that practice.

4. NIPSCO's Tracking Mechanisms: In coordination with its FAC proceedings, NIPSCO files semi- annual proceedings in: (a) Cause No. 44156-RTO-XX to recover costs associated with MISO non-fuel costs and revenues and to provide for off-system sales sharing through its Rider 871 – Adjustment of Charges for Regional Transmission Organization and Appendix C – Regional Transmission Organization Adjustment Factor ("RTO Tracker") approved by the Commission in its 45159 Rate Case Order,[6] and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs

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6 In its August 25, 2010, Order in Cause No. 43526, the Commission found that NIPSCO's MISO non-fuel costs and revenues and off system sales sharing should be included in one mechanism designated as the RTO Adjustment. In its December 21, 2011, Order in Cause No. 43969, the Commission approved the implementation of the RTO Adjustment approved in Cause No. 43526 by approving Rider 671 and Appendix C. In its July 18, 2016, Order in Cause No. 44688, the Commission approved NIPSCO's request for authority to defer, as a regulatory asset or liability, an amount equal to 50% of annual off system sales margins above or below the level of off-system sales margins included in

through its Rider 874 – Adjustment of Charges for Resource Adequacy and Appendix F – Resource Adequacy Adjustment Factor ("RA Tracker") approved by the Commission in its 45159 Rate Case Order.[7]

NIPSCO files an annual proceeding in Cause No. 43618-DSM-XX to recover program costs, lost revenues, and financial incentives associated with approved demand side management and energy efficiency programs through its Rider 883 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G - Demand Side Management Adjustment Mechanism (DSMA) Factor.[8]

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the test year for recovery through the RTO tracker. In its 45159 Rate Case Order, the Commission approved NIPSCO's request to: (1) remove MISO charges and credits and collect 100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO; (3) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology. In its April 27, 2022 Order in Cause No. 44156-RTO-21, the Commission approved, among other things, a modification of Rider 871 – Adjustment of Charges for Regional Transmission Organization to include recovery of net non-fuel PJM Interconnect LLC costs and revenues.

7 In its August 25, 2010 Order in Cause No. 43526, the Commission found that NIPSCO's prudently incurred capacity should be recovered through the Resource Adequacy or RA Adjustment. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RA Adjustment approved in Cause No. 43526 by approving Rider 674 and Appendix F. The 45159 Rate Case Order approved, among other items, the removal of all embedded capacity costs and/or credits from base rates; tracking of 100% of all capacity costs and/or credits as a charge/credit to customers through the RA Adjustment; and demand allocators for the RA Adjustment.

8 The initial tracking mechanism was approved in the Commission's May 25, 2011 Order in Cause No. 43618. In its February 27, 2017 Order in Cause No. 43618-DSM-11, the Commission approved a modification to NIPSCO's Rider 783 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) to move from a semi-annual timeline to an annual filing. In its 45159 Rate Case Order, the Commission approved Rider 883 – Demand Side Management Adjustment Mechanism and Appendix G – DSMA Factor, to become effective January 1, 2020.

NIPSCO files an annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 886 – Green Power Rider and Appendix H – Green Power Rider Rate.[9]

NIPSCO has a semi-annual tracking mechanism to recover federally mandated costs through its Rider 787 – Adjustment of Charges for Federally Mandated Costs and Appendix I – Federally Mandated Cost Adjustment Factor.[10] NIPSCO has requests for a Certificate of Public Convenience and Necessity for federally mandated projects pending in Cause Nos. 45700 and 45797 for recovery through NIPSCO's FMCA tracking mechanism.

NIPSCO files a semi-annual proceeding in Cause No. 45557-TDSIC- XX to recover 80% of eligible and approved capital expenditures and transmission, distribution, and storage system improvement charge ("TDSIC") costs through Rider 888 - Adjustment of Charges for Transmission, Distribution and Storage System

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9 The initial tracking mechanism was approved in the Commission's December 19, 2012 Order in Cause No. 44198. In its December 28, 2016 Order in Cause No. 44198-GPR-8, the Commission approved a modification to NIPSCO's Rider 786 – Green Power Rider to move from a semi-annual timeline to an annual filing. In its June 24, 2020 Order in Cause No. 44198 GPR 12, the Commission approved modifying the GPR to separate NIPSCO's recovery of certification costs from marketing costs.

10 The initial tracking mechanism was approved in the Commission's January 29, 2014 Order in Cause No. 44340. Although NIPSCO has two pending requests to utilize the FMCA tracking mechanism, NIPSCO does not currently recover any costs through the FMCA tracking mechanism.

Improvement Charge and Appendix J - Transmission, Distribution and Storage System Improvement Charge.[11]

5. This Proceeding: On September 19, 2022, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to modify its retail rates and charges for electric utility service through a phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders (both existing and new); (3) approval of a new rider for variable non-labor O&M expenses associated with coal-fired generation ("Variable Cost Tracker"); (4) modification of the fuel cost adjustment to pass back 100% of off-system sales revenues net of expenses; (5) approving revised common and electric depreciation rates applicable to its electric plant in service; (6) approving necessary and appropriate accounting relief, including but not limited to approval of (a) certain deferral mechanisms for pension and other post-retirement benefits ("OPEB") expenses, (b) regulatory accounting for actual costs of removal associated with coal units following the retirement of the last coal unit (Michigan City Generating Station ("Michigan City") Unit 12), and (c) a modification of Joint Venture accounting authority to consolidate the reserves for purposes of passing back Joint Venture cash; (7) approving alternative regulatory plans for the (a) modification of NIPSCO's industrial rate service structure, and (b) implementation of a new low income program; (8) reviewing and determining

11 The initial tracking mechanism was approved in the Commission's February 17, 2014 Order in Cause No. 44371.

the correct amount to include in NIPSCO's "earnings bank" for purposes of Ind. Code § 8-1-2-42.3; (9) authorizing NIPSCO to implement temporary rates; and (10) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on September 19, 2022. On January 20, 2023, the OUCC and intervenors filed their respective cases-in-chief and on February 16, 2023, NIPSCO filed its rebuttal testimony and exhibits and several intervenors filed cross-answering testimony and exhibits.

As discussed within NIPSCO's Verified Petition, and the testimony of various parties including NIPSCO, since the 45159 Rate Case Order, there are a few compounding drivers causing NIPSCO to request a change in rates at this time. NIPSCO is in the midst of substantial generation transition, whereby its generation fleet will be converted from one dominated by coal-fired steam generation to a modern fleet consisting predominantly of renewables, storage and natural gas. By the close of the test year, NIPSCO will have placed in service substantial investments in new utility plant, including several new renewable generating assets. NIPSCO has experienced delays, which are driven by factors outside of NIPSCO's control, in bringing all of its Commission-approved renewable energy projects online. This in turn has caused NIPSCO to continue operations of R.M. Schahfer Generating Station ("Schahfer") Units 17 and 18 longer than anticipated. The delays associated with these renewable energy projects have also required NIPSCO to take additional actions to ensure it continues to provide safe, reliable, and adequate service to its customers. Rates need to be changed to properly reflect the effects of these drivers as soon as possible.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income:

(a) Revenue Requirement: As explained further herein, the Settling Parties agree to withdraw NIPSCO's proposed Variable Cost Tracker ("VCT") and instead agree to establish a new Environmental Cost Tracker ("ECT"). The ECT will recover fewer categories of costs than the proposed VCT, and the forecasted annual costs to be recovered through the ECT are $29,880,196. The costs NIPSCO initially proposed to recover through the VCT are now being excluded from the ECT and will instead be recovered through base rates. The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount originally requested by NIPSCO in its case-in-chief. The Settling Parties agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below. Joint Exhibit A attached hereto represents the schedules supporting the calculation of the agreed upon revenue requirement based on the 12-month period ending December 31, 2023.

(b) Net Operating Income: The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income ("NOI") of $402,900,940.

2. Original Cost Rate Base, Capital Structure, and Fair Return:

(a) Original Cost Rate Base: The Settling Parties agree that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based upon this Agreement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.80%, yielding an overall return for earnings test purposes of $402,900,940, based upon:

(i) An original cost rate base of $5,925,013,822, inclusive of materials, supplies, production fuel, and regulatory assets. This amount reflects that forecasted additions to Renewable Energy Joint Venture Investments will be reduced to reflect the additional Investment Tax Credit NIPSCO will receive for Dunn's Bridge I, as reflected in NIPSCO's rebuttal alternative revenue requirement filed position. NIPSCO's current *estimate* is a reduction in additions to forecasted Joint Venture Regulatory Assets of $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660.

However, the *actual* reductions will be based on final project cost, which could be slightly more or less.

(ii) NIPSCO's forecasted capital structure; and

(iii) An authorized return on equity ("ROE") of 9.80%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.80% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$4,564,821,051	9.80%	5.06%
Long-Term Debt	$3,233,952,976	4.66%%	1.70%
Customer Deposits	$59,541,950	5.63%	0.04%
Deferred Income Taxes	$1,393,665,855	0.00%	0.00%
Post-Retirement Liability	$13,945,116	0.00%	0.00%
Prepaid Pension Asset	$(424,946,780)	0.00%	0.00%
Post-1970 ITC	$640,278	7.67%	0.00%
Totals	**$8,841,620,445**		**6.80%**

3. Depreciation and Amortization Expense:

(a) Depreciation Expense: The Settling Parties agree that the depreciation accrual rates recommended by NIPSCO in this proceeding should be approved with the following exceptions:

(i) The amortization period for retired coal-fired generating units and the regulatory assets resulting from regulatory accounting authorized by the 45159 Rate Case Order shall conclude June 30, 2034. This produces a reduction of approximately $26.0 Million in depreciation expense and a reduction of an additional approximate $8.8 Million for the amortization of the regulatory asset resulting from the retirement of Schahfer Units 14 and 15.

(ii) Pro forma depreciation expense will be increased approximately $9.8 Million to reflect additional demolition costs for Schahfer and Michigan City.

(iii) NIPSCO will move to stay Cause No. 45700, and upon Commission approval of all terms of this Agreement, NIPSCO shall move to dismiss Cause No. 45700 with prejudice. NIPSCO will move to stay Cause No. 45797, including staying all post-hearing briefing, and upon Commission approval of all terms of this Agreement, NIPSCO shall move to dismiss Cause No. 45797. In the event this Agreement is not approved in its entirety and with respect to NIPSCO's recovery of costs in relation to the projects proposed in Cause No. 45797, the non-NIPSCO parties in Cause No. 45797[12] agree to not object on the basis of the timeliness of the Petition in that Cause or issuance of a Commission order in that Cause, to recovery of costs incurred by NIPSCO after June 1, 2023, in relation to the projects proposed in that Cause. In the event the Commission rejects this Agreement, NIPSCO will move to lift the stay in those

12 This includes the OUCC, NIPSCO Industrial Group, and CAC.

proceedings, and except as otherwise agreed to above with respect to Cause No. 45797, litigation will resume in both Causes, with all parties able to take any position in the Causes as may be justified by the law and the facts and that are not inconsistent with the terms of this Agreement.

(iv) Depreciation rates for non-coal-fired generation assets shall be reduced, to produce an additional $9.5 Million reduction.

(v) Depreciation rates will be calculated by NIPSCO to produce these changes and will be included in the testimony supporting this Agreement, to be filed on March 17, 2023.

(b) Amortization Expense: The Settling Parties agree that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding with the following exceptions:

(i) The Cause No. 45159 regulatory asset amortization expense will be adjusted by an $8.22 Million annual reduction.

(ii) There will be a $1.7 Million annual reduction from moving the amortization periods for COVID and Rate Case Expense regulatory asset balances from two to four years.

(iii) There will be a $3.1 Million annual reduction from moving the amortization period for FMCA and TDSIC regulatory asset balances from four to seven years.

(iv) NIPSCO will make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement, and rates will be adjusted accordingly.

(c) Future Cost of Removal and Regulatory Accounting:

(i) NIPSCO will not file federal mandate cases pursuant to Ind. Code ch. 8-1-8.4 to recover costs to satisfy any asset retirement obligations associated with coal-fired generation. Instead, NIPSCO will debit FERC Account 108 for reasonable and prudent costs incurred for removal cost associated with coal-fired generation per the FERC Uniform System of Accounts, which entry will be reflected in future depreciation studies. NIPSCO will seek to adjust its future depreciation studies to reflect reasonable and prudent retirement costs.

(ii) The Settling Parties agree regulatory accounting for cost of removal (COR) for its coal-fired generation related assets should be approved as outlined in NIPSCO Witness Shikany's direct testimony (pp. 117-119) in this Cause and agree to the creation of a regulatory liability or asset, as applicable, to be included in future base rates upon the elimination of the appropriate FERC

Plant-in-Service account, subject to any challenge permitted by law, including the reasonableness and prudence of the cost.

4. Pro Forma Net Operating Income at Present Rates:

(a) Revenues: The Settling Parties accept a portion of the proposed increase in the residential sales forecast proposed by Industrial Group, which increases revenues by approximately $2.0 Million.

(b) Labor: The Settling Parties agree NIPSCO's proposed adjustment for vacant positions will be reduced by $2.2 Million.

(c) Pension and OPEB Expense: The Settling Parties accept NIPSCO's proposed adjustment to increase Pension and OPEB Expense by a combined $15.2 Million based upon the most recent actuarial report available prior to the filing of NIPSCO's case-in-chief. NIPSCO withdraws its request for a pension/OPEB balancing account.

(d) Vegetation Management: The Settling Parties agree NIPSCO's proposed vegetation management expense will be reduced by $5.8 Million, resulting in a total annual vegetation management expense of $25.1 Million (NIPSCO's 2022 budgeted expense escalated by a 5.20% inflation factor).

(e) Fuel Costs: The Settling Parties agree the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $25.0 Million.

(f) Schahfer Fire: The Settling Parties agree a $1.06 million annual O&M reduction will be made in this case and through June 30, 2034 to resolve all known and/or disclosed issues related to the fire at Schahfer in July of 2020. NIPSCO will propose this same O&M reduction of $1.06 million per year in future general rate cases. This term shall survive the termination of this Agreement and expire on June 30, 2034. NIPSCO represents that it is unaware of any facts that would support a claim for disallowance of any expenses or costs that could be attributable to the fire that has not already been presented to the Commission. The Settling Parties reserve all rights to pursue further adjustments should previously unknown or undisclosed facts support further disallowance.

(g) Other O&M: The Settling Parties agree a further reduction to O&M in this case shall be made, to reduce O&M by a total of $4.7 Million. This reduction addresses, among other issues, CAC's proposed disallowance of Edison Electric Institute expenses.

5. Environmental Cost Tracker: NIPSCO's proposed Variable Cost Tracker shall be renamed the Environmental Cost Tracker ("ECT") and shall be approved, using the filing methodology and frequency described by NIPSCO Witness Blissmer, except as modified herein. The only costs to be recovered through the ECT are NOx emissions allowances and variable chemical costs (estimated to be $30 Million per year). The ECT will be allocated among rate classes on the basis of energy. For Rate 526, the Settling

Parties agree to a demand-based rate design, with recovery through demand charges. NIPSCO will make good faith efforts to monetize unused NOx allowances, with 100% of benefits passed to NIPSCO customers through the ECT, to re-evaluate procurement practices, and to report on monetization in each ECT tracker filing. The costs associated with generation maintenance and outages originally proposed by NIPSCO as part of the VCT will be embedded in base rates in the amount estimated by NIPSCO in its case-in-chief of approximately $72 Million. For the costs that will be included in base rates, the Settling Parties agree that these costs will be allocated in the same manner that these costs were allocated in Cause No. 45159 to maintain the "status quo" regarding allocation, which includes both a demand- and energy-based allocation component.

6. <u>Phased Rate Implementation:</u>

(a) <u>Step 1 Rates Subject to Refund:</u> Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023 and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023. NIPSCO will provide all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All Parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on or about March 1, 2024 and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2023. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) Additional Interim Phases: In the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully in service by June 30, 2023 (meaning the portion that is not certified as partially in service as described in Mr. Campbell's rebuttal testimony) but come into service on or before December 31, 2023, then an additional interim step will be implemented after Step 1 and before Step 2. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

7. <u>Cost of Service, Rate Design and Rate 831/531 Settlement:</u>

(a) <u>Rate 831/531 Settlement.</u> All Settling Parties agree to support or not oppose adoption of the Rate 831/531 Settlement. All Parties not signatories to the Rate 831/531 Settlement retain all rights in future proceedings to take any position with respect to cost of service and Rate 531 issues.

(b) <u>Mitigation.</u> The Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, residential rates under Rate 511 are being subsidized by several other rate classes, including, but not limited to, Rate 520 through Rate 533. For this reason, the Settling Parties have agreed to mitigating a portion of the subsidy in this Agreement consistent with the Commission's policy of gradualism. The reduction in annual revenue (*i.e.*, the annual revenue below NIPSCO's as-filed case) will be allocated: 1st to maintain Rate 531 at cost of service based on 180 megawatts ("MW") of allocated demand as reflected in Rate 831/531 Settlement; 2nd 25% of the remaining amount for subsidy reduction; and 3rd with the 75% remaining amount allocated on an across-the-board basis. Because Rate 831 is being brought to parity at 180 MW of allocated demand, it will not receive either a reduction to reduce subsidies (the 25% portion) or a reduction on an across-the-board basis (the 75% portion). Rate 811 rates will participate in the across-the-board reduction (the 75% portion). Rates will be designed so that no rate class that is currently being subsidized will move to subsidizing other rates, and no rate that is currently subsidizing other rate classes will move to being subsidized by other rates. The provisions of this paragraph will be implemented in the cost of service and rates included with NIPSCO's settlement testimony, which will be submitted to the Commission by March 17, 2023.

(c) Industrial Group-Specific Issues. The Industrial Group agrees not to pursue its proposal for voltage-adjusted FAC and revised allocation for renewable resources in this case. All Settling Parties retain all rights in future proceedings to litigate these issues.

(d) Production Demand Allocation in Future Cases. In its next electric base rate case, NIPSCO will prepare a 4 coincident peak ("CP") and 12 CP cost of service analysis for purposes of allocating production-related demand costs and make each analysis available to all parties in the case. NIPSCO will determine which cost of service analysis to propose in its case-in-chief, and all other parties will have the right to take any position with regard to cost of service in that case.

(e) Increases in Load by Rate 531 Customers. The Settling Parties will discuss concerns relating to protections for other classes in the event of future increases in firm load by new or existing Rate 531 customers, including any appropriate clarifications.

(f) Future Reductions in Tier 1 Load and Cost Allocations. Future reductions to Tier 1 load and cost allocations to Rate 531 as contemplated in the Rate

831/531 Settlement will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates, pursuant to the following provisions. The process for determining future reductions in Tier 1 load and cost allocations to Rate 531 shall be as follows: (a) the relevant comparison is between end of test year in prior rate case and end of test year in subsequent rate case; (b) the measure of costs for legacy coal assets includes capital balances for coal assets, as well as fixed O&M, coal inventory, and other base rate inclusions; (c) the starting point is the proposed Rate 531 tariff terms and conditions, 180 MW of Rate 531 class demand, and 170 MWs of Rate 531 contract demand commitments per the Rate 831/531 Settlement, and the eventual end point, based on the current composition of the class, is 70 MW of both Rate 531 Tier 1 class demand and actual contract demand, with future proportional adjustments reducing the prevailing 110 MW differential between the current Rate 531 class demand and the end point; (d) consistent with the Rate 831/531 Settlement, successive future adjustments will involve both reductions in Tier 1 Rate 531 class allocations and contract demand commitments to progressively narrow the spread between allocated Rate 531 class demand and actual contract demand for the class; and (e) the above methodology assumes existing class composition throughout legacy coal asset recovery period, subject to an agreed process to address any material changes in circumstance. Nothing in this Agreement shall obligate a class member to increase its Tier 1 contract demand commitments in the future.

(g) Material Changes in Circumstances. The signatories to the Rate 831/531 Settlement and OUCC will meet and confer in the event of any material change of circumstances affecting the composition of the class or the class load, with the following clarifications: (a) no class member is prohibited from exiting the rate upon expiration of the contractual term; (b) existing tariff provisions on modifying commitments in the event of a facility closure remain in force; (c) in the event a class member exits the rate, the allocated demand and total contracted demand for the class will be reduced correspondingly provided that the exiting customer is migrating to another rate schedule with a like firm demand or the exit from Rate 531 is attributable to a facility closure or material reduction in load; (d) in the event that a class member increases Tier 1 load then other class members not at tariff minimum may decrease Tier 1 commitments correspondingly to maintain class load at agreed levels; (e) in the event a new customer joins the rate class then existing customers with firm demand above the tariff minimum will be permitted to reduce Tier 1 commitments so long as the class load is maintained at the agreed levels; and (f) recognizing that not all contingencies can be anticipated and addressed in advance, any signatory to the Rate 831/531 Settlement or the OUCC may initiate discussions in the event of a material change of circumstances and, absent agreement, may submit the issue for resolution by the Commission.

(h) Rate 526. Considering that significant amounts of demand costs are being recovered through the energy charge, the revenue reduction as a result of this

Agreement that is allocated to Rate 526 will be used to reduce the energy charge until all energy and demand components of Rate 526 match NIPSCO's energy/demand cost of service levels.

(i) Customer Charges. Customer charges proposed by NIPSCO shall be approved, except NIPSCO's existing monthly charge for Rate 511 shall be increased to $14.00 and the existing monthly charge for Rate 521 shall be increased to $32.50.

(j) Multi Family Rate. NIPSCO will collect data on residential customer housing types to identify multi-family customers and analyze cost differentials between single- and multi-family residential customers. NIPSCO will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, NIPSCO will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested stakeholder the results of its analysis.

(k) Rate 532. As part of preparing cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to this rate or the creation of another rate for current customers in Rate 532 is appropriate. This review will include, but will not be limited to, a review of the appropriate minimum demand level for participation in Rate 532 and demand blocks and demand and energy charges. NIPSCO will make this information available to any member of this rate class and/or their consultants who request such information.

(l) Rate 550. The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511.

(m) Survival of Terms of Paragraphs 4(f) and 7(f) and (g). The terms in Paragraphs 4(f) and 7(f) and (g) relating to O&M reduction relating to Schahfer fire, future reductions in Tier 1 load, and cost allocations to Rate 531, shall survive the termination of this Agreement.

8. Low Income Program and Issues. NIPSCO agrees to withdraw its proposed Low Income Program. However, NIPSCO retains the right to seek approval of a low income program in the future. In recognition of concerns expressed by the OUCC and CAC, NIPSCO will contribute below the line (*i.e.*, not to be recovered through rates) a total of $400,000 to Indiana Community Action Association for the Community Action Programs to enable Community Action Program health and safety work for the low income weatherization program. These contributions will be made in $100,000 increments in calendar years 2024, 2025, 2026, and 2027.

9. Distributed Generation. As part of the annual Performance Metrics Report filed pursuant to the Commission's July 18, 2016 Order in Cause No. 44688, NIPSCO agrees to include monthly data that separately provides data on Excess

Distributed Generation tariff and Small Power Production tariff customer participation, broken down by residential and non-residential customers, and including data on both new and total (a) capacity (kW-ac) installed, (b) number of customers, and (c) size of battery storage system (both kW and kWh) if one is part of the customer's system.

10. <u>Demand Response.</u> NIPSCO will continue to work with its Energy Efficiency Oversight Board ("OSB") on appropriate demand response programs. NIPSCO will work with its OSB on how best to model demand response for its next integrated resource plan, including but not limited to inclusion in the demand side management market potential study. NIPSCO will work with its OSB to do a request for proposals for demand response programs, either as part of an all-source request for proposals or as a stand-alone event.

11. <u>Infrastructure Investment and Jobs Act ("IIJA") / Inflation Reduction Act ("IRA").</u> NIPSCO will meet with CAC and other interested stakeholders to evaluate potential opportunities associated with the IIJA and IRA that could be reasonably pursued by NIPSCO to the benefit of NIPSCO's customers. NIPSCO will provide CAC and other interested stakeholders with the results of its evaluation and provide the parties the opportunity to comment on NIPSCO's evaluation. Meetings will begin within 60 days of execution of this Agreement.

12. Indiana Municipal Utility Group.[13] IMUG is agreeing to not oppose this Agreement for the consideration and commitments contained in Addendum A, which provisions the Settling Parties agree to support or not oppose.

13. RV Users Group. The RV Group is signing this Agreement to receive the benefits contained herein and for the consideration and commitments contained in Addendum B, which NIPSCO agrees to support, but which other Settling Parties will not oppose. With respect to the RV Group TDSIC provisions in Addendum B, the Settling Parties (other than NIPSCO) take no position on and do not endorse such provisions but will not oppose them.

14. Other Relief Requested by NIPSCO. The Settling Parties agree that all other aspects of NIPSCO's case-in-chief, as modified in its rebuttal testimony, should be approved.

C. Procedural Aspects and Presentation of the Agreement

1. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the simplification and minimization of issues to be presented in the proceeding.

2. The Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding and agree to assist and cooperate in the

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13 Indiana Municipal Utility Group is comprised of Towns of Schererville, Dyer, and the City of East Chicago.

preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval. All evidence which has been prefiled by the Settling Parties will be admitted into the record. All Settling Parties waive cross-examination on all witnesses of other Settling Parties but reserve the right to ask questions of any witness who may be cross-examined by a non- settling party.

3. The concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications. If the Agreement is withdrawn, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. In the event the Agreement is withdrawn, the Settling Parties will request an Attorney's Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

4. The Settling Parties acknowledge that this Settlement Agreement addresses all issues in the proceeding, including the appropriate revenue requirement and allocation of costs, and includes compromises upon the part of each Settling Party. The Settling Parties agree that this Agreement and each term, condition, amount,

methodology, and exclusion contained herein (a) reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement; (b) has accounted for the overall level of risk presented to NIPSCO by the Settlement Agreement; and (c) is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

5. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it, without objection.

6. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

7. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement, and the Settling Parties shall not support any appeal of any portion of the of Final Order by any person not a party to this Agreement.

8. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

9. The terms set forth in this Agreement are the complete and final agreement among the Settling Parties. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 10th day of March, 2023.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

William Fine

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NIPSCO Industrial Group

Todd Richardson

NLMK Indiana

James W Breen
3-10-2023

United States Steel Corporation

Kristina Kern Wheeler

RV Industry User's Group

Walmart Inc.

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	Operating Revenue							
2	Revenue (Actual / Pro Forma)	$ 1,700,765,620		REV, Col A	$ 1,505,336,512	261,923,892	PF - 1 - S	$ 1,767,260,404
3	Pro forma Adjustments December 31, 2021		(19,779,195)	REV, Col B				
4	Budget Adjustments December 31, 2022		(51,640,914)	REV, Col D				
5	Budget Adjustments December 31, 2023		19,012,369	REV, Col F				
6	Ratemaking Adjustments December 31, 2023		(143,021,367)	REV-S, Col H				
7	Total Operating Revenue	$ 1,700,765,620	$ (195,429,108)		$ 1,505,336,512	$ 261,923,892		$ 1,767,260,404
8	Fuel & Purchased Power							
9	Fuel Cost (Actual / Pro Forma)	$ 416,398,339		COGS, Col A	$ 367,509,634	-		$ 367,509,634
10	Pro forma Adjustments December 31, 2021		(3,843,760)	COGS, Col B				
11	Budget Adjustments December 31, 2022		(25,895,162)	COGS, Col D				
12	Budget Adjustments December 31, 2023		(4,860,689)	COGS, Col F				
13	Ratemaking Adjustments December 31, 2023		(14,289,094)	COGS-S, Col H				
14	Total Fuel and Purchased Power Costs	$ 416,398,339	$ (48,888,705)		$ 367,509,634			$ 367,509,634
15	**Gross Margin**	$ 1,284,367,281	$ (146,540,403)		$ 1,137,826,878	$ 261,923,892		$ 1,399,750,770
16	Operations and Maintenance Expenses							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 493,605,075		O&M, Col A	$ 488,572,809	671,748	PF - 2 - S	$ 489,244,558
18	Pro forma Adjustments December 31, 2021		(23,438,011)	O&M, Col B				
19	Budget Adjustments December 31, 2022		44,307,375	O&M, Col D				
20	Budget Adjustments December 31, 2023		42,240,218	O&M, Col F				
21	Ratemaking Adjustments December 31, 2023		(68,141,848)	O&M-S, Col H				
22	Total Operations and Maintenance Expense	$ 493,605,075	$ (5,032,265)		$ 488,572,809	$ 671,748		$ 489,244,558
23	Depreciation Expense							
24	Depreciation Expense (Actual / Pro Forma)	$ 300,041,895		DEPR, Col A	$ 286,232,067			$ 286,232,067
25	Pro forma Adjustments December 31, 2021		(10,408,351)	DEPR, Col B				
26	Budget Adjustments December 31, 2022		4,307,754	DEPR, Col D				
27	Budget Adjustments December 31, 2023		19,336,047	DEPR, Col F				
28	Ratemaking Adjustments December 31, 2023		(27,045,278)	DEPR-S, Col H				
29	Total Depreciation Expense	$ 300,041,895	$ (13,809,828)		$ 286,232,067	$ -		$ 286,232,067

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 28,049,666		AMTZ, Col A	$ 118,760,693			$ 118,760,693
32	Pro forma Adjustments December 31, 2021		33,681,838	AMTZ, Col B				
33	Budget Adjustments December 31, 2022		35,261,815	AMTZ, Col D				
34	Budget Adjustments December 31, 2023		20,002,648	AMTZ, Col F				
35	Ratemaking Adjustments December 31, 2023		1,764,724	AMTZ-S, Col H				
36	Total Amortization Expense	$ 28,049,666	$ 90,711,026		$ 118,760,693	$ -		$ 118,760,693
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 56,893,980		OTX, Col A	$ 35,531,910			$ 35,531,910
40	Pro forma Adjustments December 31, 2021		(608,134)	OTX, Col B				
41	Budget Adjustments December 31, 2022		11,539,562	OTX, Col D				
42	Budget Adjustments December 31, 2023		(609,441)	OTX, Col F				$ -
43	Ratemaking Adjustments December 31, 2023		(31,684,057)	OTX, Col H		334,236	PF - 3 - S	$ 334,236
44	Total Taxes Other Than Income	$ 56,893,980	$ (21,362,070)		$ 35,531,910	$ 334,236		$ 35,866,145
45	**Operating Income Before Income Taxes**	$ 405,776,664	$ (197,047,265)		$ 208,729,399	$ 260,917,908		$ 469,647,307
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 55,596,061	(53,742,587)	Attachment 3-C-S, ITX 1-S	$ 1,853,474	64,892,893	PF - 4 - S	$ 66,746,367
48	Total Taxes	$ 112,490,040	$ (75,104,657)		$ 37,385,384	$ 65,227,129		$ 102,612,512
49	**Total Operating Expenses including Income Taxes**	$ 934,186,677	$ (3,235,724)		$ 930,950,953	$ 65,898,877		$ 996,849,830
50	**Required Net Operating Income**	$ 350,180,604	$ (143,304,679)		$ 206,875,925	$ 196,025,015		$ 402,900,940

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company LLC
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2023

Line No.	Description	Revenue Deficiency
1	Net Original Cost Rate Base	$ 5,925,013,822
2	Rate of Return	6.80%
3	Net Operating Income	$ 402,900,940
4	Pro forma Net Operating Income	$ 206,875,925
5	Increase in Net Operating Income (NOI Shortfall)	$ 196,025,015
6	Effective Incremental Revenuel NOI Conversion Factor	74.84%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$ 261,923,892

8	One		1.000000			
9	Less: Public Utility Fee		0.001276			
10	Less: Bad Debt		0.002565			
11	State Taxable Income			0.996159		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	-				
14	Taxable Adjusted Gross Income Tax		0.996159			
15	Adjusted Gross Income Tax Rate		0.049000			
16	Adjusted Gross Income Tax			0.048812		
17	Line 11 less line 13 less line 16				0.947347	
18	One			1.000000		
19	Less: Federal Income Tax Rate			0.210000		
20	One Less Federal Income Tax Rate				0.790000	
21	Effective Incremental Revenue / NOI Conversion Factor					74.840%

Attachment A

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2023

Line No.	Description		Pro forma As Of December 31, 2023	Attachment 3-B-S2-S Reference
	Rate Base			
1	Utility Plant	$	8,252,008,653	RB, Col I
2	Common Allocated		384,894,416	RB, Col I
3	**Total Utility Plant**	**$**	**8,636,903,069**	RB, Col I
4	Accumulated Depreciation and Amortization		(4,069,667,383)	RB, Col I
5	Common Allocated		(245,419,231)	RB, Col I
6	**Total Accumulated Depreciation and Amortization**	**$**	**(4,315,086,614)**	RB, Col I
7	**Net Utility Plant**	**$**	**4,321,816,455**	RB, Col I
8	RMS Unit 14/15 Retirement	$	593,022,393	RB, Col I
9	Joint Venture Reg Assets		817,299,925	RB, Col I
10	Reg Assets - Cause 44688 & 45159		23,510,338	RB, Col I
11	Electric 2021-2026 TDSIC Plan Cause #45557		24,558,486	RB, Col I
12	FMCA - Post 45159 & CCR Remediation		545,389	RB, Col I
13	Materials & Supplies		98,989,010	RB, Col I
14	Production Fuel		45,271,825	RB, Col I
15	**Total Rate Base**	**$**	**5,925,013,822**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure - S2
As Of December 31, 2023

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 4,564,821,051	51.63%	9.80%	5.06%
2	Long-Term Debt	3,233,952,976	36.58%	4.66%	1.70%
3	Customer Deposits	59,541,950	0.67%	5.63%	0.04%
4	Deferred Income Taxes	1,393,665,855	15.76%	0.00%	0.00%
5	Post-Retirement Liability	13,945,116	0.16%	0.00%	0.00%
6	Prepaid Pension Asset	(424,946,780)	-4.81%	0.00%	0.00%
7	Post-1970 ITC	640,278	0.01%	7.67%	0.00%
8	Totals	**$ 8,841,620,445**	**100.00%**		**6.80%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 4,564,821,051	58.53%	9.80%	5.74%
10	Long-Term Debt	3,233,952,976	41.47%	4.66%	1.93%
11	**Totals**	**$ 7,798,774,027**	**100.00%**		**7.67%**

Attachment A

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 1,700,765,620		REV, Col A	$ 1,505,336,512	291,804,089	PF - 1- S-ALT	$ 1,797,140,601
3	Pro forma Adjustments December 31, 2021		(19,779,195)	REV, Col B				
4	Budget Adjustments December 31, 2022		(51,640,914)	REV, Col D				
5	Budget Adjustments December 31, 2023		19,012,369	REV, Col F				
6	Ratemaking Adjustments December 31, 2023		(143,021,367)	REV-S, Col H				
7	Total Operating Revenue	$ 1,700,765,620	$ (195,429,108)		$ 1,505,336,512	$ 291,804,089		$ 1,797,140,601
8	**Fuel & Purchased Power**							
9	Fuel Cost (Actual / Pro Forma)	$ 416,398,339		COGS, Col A	$ 367,509,634	-		$ 367,509,634
10	Pro forma Adjustments December 31, 2021		(3,843,760)	COGS, Col B				
11	Budget Adjustments December 31, 2022		(25,895,162)	COGS, Col D				
12	Budget Adjustments December 31, 2023		(4,860,689)	COGS, Col F				
13	Ratemaking Adjustments December 31, 2023		(14,289,094)	COGS-S, Col H				
14	Total Fuel and Purchased Power Costs	$ 416,398,339	$ (48,888,705)		$ 367,509,634			$ 367,509,634
15	**Gross Margin**	$ 1,284,367,281	$ (146,540,403)		$ 1,137,826,878	$ 291,804,089		$ 1,429,630,966
16	**Operations and Maintenance Expenses**							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 493,605,075		O&M, Col A	$ 518,338,243	748,381	PF - 2 - S-ALT	$ 519,086,625
18	Pro forma Adjustments December 31, 2021		(23,438,011)	O&M, Col B				
19	Budget Adjustments December 31, 2022		44,307,375	O&M, Col D				
20	Budget Adjustments December 31, 2023		42,240,218	O&M, Col F				
21	Ratemaking Adjustments December 31, 2023		(38,376,414)	O&M-S, Col H				
22	Total Operations and Maintenance Expense	$ 493,605,075	$ 24,733,169		$ 518,338,243	$ 748,381		$ 519,086,625
23	**Depreciation Expense**							
24	Depreciation Expense (Actual / Pro Forma)	$ 300,041,895		DEPR, Col A	$ 286,232,067			$ 286,232,067
25	Pro forma Adjustments December 31, 2021		(10,408,351)	DEPR, Col B				
26	Budget Adjustments December 31, 2022		4,307,754	DEPR, Col D				
27	Budget Adjustments December 31, 2023		19,336,047	DEPR, Col F				
28	Ratemaking Adjustments December 31, 2023		(27,045,278)	DEPR-S, Col H				
29	Total Depreciation Expense	$ 300,041,895	$ (13,809,828)		$ 286,232,067	$ -		$ 286,232,067

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 28,049,666		AMTZ, Col A	$ 118,760,693			$ 118,760,693
32	Pro forma Adjustments December 31, 2021		33,681,838	AMTZ, Col B				
33	Budget Adjustments December 31, 2022		35,261,815	AMTZ, Col D				
34	Budget Adjustments December 31, 2023		20,002,648	AMTZ, Col F				
35	Ratemaking Adjustments December 31, 2023		1,764,724	AMTZ-S, Col H				
36	Total Amortization Expense	$ 28,049,666	$ 90,711,026		$ 118,760,693	$ -		$ 118,760,693
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 56,893,980		OTX, Col A	$ 35,531,910			$ 35,531,910
40	Pro forma Adjustments December 31, 2021		(608,134)	OTX, Col B				
41	Budget Adjustments December 31, 2022		11,539,562	OTX, Col D				
42	Budget Adjustments December 31, 2023		(609,441)	OTX, Col F		-		$ -
43	Ratemaking Adjustments December 31, 2023		(31,684,057)	OTX, Col H		372,365	PF - 3 - S-ALT	$ 372,365
44	Total Taxes Other Than Income	$ 56,893,980	$ (21,362,070)		$ 35,531,910	$ 372,365		$ 35,904,275
45	**Operating Income Before Income Taxes**	$ 405,776,664	$ (226,812,699)		$ 178,963,965	$ 290,683,342		$ 469,647,307
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 55,596,061	(61,145,548)	Attachment 3-C-S, ITX 1 - S-ALT	$ (5,549,487)	72,295,854	PF - 4 - S-ALT	$ 66,746,367
48	Total Taxes	$ 112,490,040	$ (82,507,618)		$ 29,982,423	$ 72,668,219		$ 102,650,642
49	**Total Operating Expenses including Income Taxes**	$ 934,186,677	$ 19,126,749		$ 953,313,426	$ 73,416,601		$ 1,026,730,026
50	**Required Net Operating Income**	$ 350,180,604	$ (165,667,152)		$ 184,513,452	$ 218,387,488		$ 402,900,940

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company LLC
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2023

Line No.	Description		Revenue Deficiency
1	Net Original Cost Rate Base	$	5,925,013,822
2	Rate of Return		6.80%
3	Net Operating Income	$	402,900,940
4	Pro forma Net Operating Income	$	184,513,452
5	Increase in Net Operating Income (NOI Shortfall)	$	218,387,488
6	Effective Incremental Revenuel NOI Conversion Factor		74.84%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$	291,804,089

8	One		1.000000			
9	Less: Public Utility Fee		0.001276			
10	Less: Bad Debt		0.002565			
11	State Taxable Income			0.996159		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	-				
14	Taxable Adjusted Gross Income Tax		0.996159			
15	Adjusted Gross Income Tax Rate		0.049000			
16	Adjusted Gross Income Tax			0.048812		
17	Line 11 less line 13 less line 16				0.947347	
18	One			1.000000		
19	Less: Federal Income Tax Rate			0.210000		
20	One Less Federal Income Tax Rate				0.790000	
21	Effective Incremental Revenue / NOI Conversion Factor					74.840%

Northern Indiana Public Service Company LLC
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As Of December 31, 2023

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4	Accumulated Depreciation and Amortization		(4,069,667,383)	RB, Col I
5	Common Allocated		(245,419,231)	RB, Col I
6	**Total Accumulated Depreciation and Amortization**	**$**	**(4,315,086,614)**	RB, Col I
7	**Net Utility Plant**	**$**	**4,321,816,455**	RB, Col I
8	RMS Unit 14/15 Retirement	$	593,022,393	RB, Col I
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15	**Total Rate Base**	**$**	**5,925,013,822**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure
As Of December 31, 2023

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
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2	Long-Term Debt	3,233,952,976	36.58%	4.66%	1.70%
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4	Deferred Income Taxes	1,393,665,855	15.76%	0.00%	0.00%
5	Post-Retirement Liability	13,945,116	0.16%	0.00%	0.00%
6	Prepaid Pension Asset	(424,946,780)	-4.81%	0.00%	0.00%
7	Post-1970 ITC	640,278	0.01%	7.67%	0.00%
8	Totals	**$ 8,841,620,445**	**100.00%**		**6.80%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 4,564,821,051	58.53%	9.80%	5.74%
10	Long-Term Debt	3,233,952,976	41.47%	4.66%	1.93%
11	**Totals**	**$ 7,798,774,027**	**100.00%**		**7.67%**

Addendum A

Settlement Agreement Addendum Responsive to the Indiana Municipal Utility Group ("IMUG") Recommendations[1]

1) IMUG will in writing not oppose the Settlement Agreement in Cause No. 45772. This includes IMUG and all Settling or not opposing Parties waiving cross-examination of all Settling Parties' witnesses, but IMUG reserves the right to ask questions of any witness that does appear and is crossed by a non-settling party, or crossed in a manner contrary to IMUG's benefits from this Settlement.

2) Streetlights provide essential important public service benefits through nighttime public safety and through promotion of nighttime economic development and social activities. Those public service benefits are further enhanced through the superior lighting provided by modern LED streetlights. NIPSCO's municipal electric customers are public services providers who pay for street lighting and an array of other essential public services through limited municipal budgets without profit motivation. Those municipal streetlight public service efforts primarily benefit and protect NIPSCO area residents. As such it is agreed that:

3) NIPSCO will fund energy efficiency audits and new efficiency measures including LEDs for each of the three participating municipality members of IMUG (as of March 3, 2023), at a maximum cost of up to $25,000 per municipality. NIPSCO will work with the IMUG members to choose a mutually agreeable company or consultant to perform these energy efficiency audits. If a program or project qualifies for NIPSCO's energy efficiency program, this will qualify as a "new energy efficiency measure" under this term, and the customer cost (after rebate) would qualify for reimbursement under this term. NIPSCO and the municipalities will work in good faith as to what qualifies as a "new energy efficiency measure."

4) The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511 as stipulated in Section 7 (l) of the Settlement Agreement.

5) NIPSCO will lend its expertise to any IMUG member that seeks to convert customer-owned streetlights to LEDs, e.g., meetings, exchange of info, sharing access to consultants for learning and knowledge, etc.

6) NIPSCO will work with IMUG to seek to improve its record keeping for LED and HPS street lighting so that the records will differentiate between the type of fixture (*e.g.*, LED, MV, HPS) and the type of repair made.

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[1] Indiana Municipal Utility Group is comprised of Towns of Schererville, Dyer, and the City of East Chicago.

ACCEPTED AND AGREED this 10th day of March, 2023.

[SIGNATURE PAGES FOLLOW]

Addendum A

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Municipal Utility Group

Theodore J Sommer

Addendum B

Settlement Terms between NIPSCO and the RV Industry User's Group ("RV Group")[1]

1) NIPSCO has already begun work on necessary steps to update and upgrade the Mingus Ditch substation which is a required precursor step to system redundancies and reliability improvements in the Goshen/Elkhart County service territory. To the extent feasible, NIPSCO will also speed up the construction of the two substation projects that are discussed in Ronald Talbot's rebuttal testimony in this proceeding (2025 and 2026 projects, which are already identified in and are part of NIPSCO's approved electric TDSIC Plan).

2) NIPSCO commits to fund energy efficiency audits of up to $50,000 per customer for each of the four RV Group members. NIPSCO and the RV Group members will work together to select a mutually satisfactory, qualified company or consultant to perform these energy efficiency audits and to coordinate to ensure viable and cost effective energy efficient proposals and opportunities are identified.

3) NIPSCO agrees to include RV Group representatives in discussions with the DSM Oversight Board related to participating in existing or proposing additional demand response program opportunities available to or that could be expanded to provide additional benefits to RV Group Members and lower NIPSCO peak energy needs. NIPSCO is separately committed to issuing an RFI and/or RFI for demand response as part of its next RFP that shall include and allow for RV Group member proposals consistent with these objectives.

4) NIPSCO will, separately from the DSM Oversight Board process, directly work with and assist the RV Group representatives in determining potential savings, programs, and funding opportunities through its DSM program and any other available Commission-approved processes. To the extent savings are identified that are not current DSM or other programs/measures, NIPSCO will make a good faith effort to add such program/measure to its DSM plan(s).

5) As part of preparing its cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of each of the Members of the RV Group to determine if a new or adjusted rate schedule is appropriate for these customers and customers of similar characteristics who

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1 The RV Industry User's Group is comprised of LCI Industries, Inc.; Patrick Industries, Inc.; Forest River, Inc.; and Keystone RV Company.

would qualify. As part of these efforts, NIPSCO agrees to make any relevant information available to the RV Group and/or their consultants.

6) As part of its next electric base rate case, subject to any necessary non-disclosure protections, NIPSCO agrees to prepare a 4CP cost of service analysis for purposes allocating production-related costs and make this available to the RV Group in advance of such filing, as well as to any other party subsequently participating in the case who requests it. This analysis shall conform to and be consistent with the principles of cost causation identified by NIPSCO in this and NIPSCO's last base rate case in Cause No. 45159. This does not, however, limit NIPSCO in determining which cost of service analysis it chooses to propose in its case-in-chief, nor does it impact any other parties' right to take any position with regards to cost of service or allocations in that next rate case.

7) NIPSCO commits to meeting with RV Group representatives to review and discuss cost of service concerns before NIPSCO files its next electric base rate case is filed.

RV Group TDSIC Project(s)

8) NIPSCO and the RV Group agree that the RV Group may propose one or more projects to be included as part of NIPSCO's TDSIC Plan (currently under Cause No. 45557) totaling up to $3.5 million, provided each project meets the applicable requirements of the TDSIC Statute (Ind. Code ch. 8-1-39). This agreed upon commitment and benefit shall be reserved for the benefit of the RV Group Members and any TDSIC Plan request made by an RV Group Member shall be for qualifying infrastructure upgrade needs that improve reliability and/or spur economic development, which include, but are not limited to upgrades to substations, transformers, distribution and transmission facilities, or other necessary electrical system upgrades to provide service to an RV Group member ("RV Group TDSIC Project(s)"). NIPSCO shall seek approval for inclusion of such RV Group TDSIC Projects and the related funding as part of NIPSCO's TDSIC Plan. To manage the allocation of the RV Group TDSIC Project(s), a Fund shall be pursued as part of NIPSCO's existing TDSIC process. The Fund shall not lapse or be transferred to other NIPSCO customers, but any NIPSCO system upgrades or facilities built to support any RV Group TDSIC Project(s) may also be used to serve other customers, provided this does not diminish service reliability for the RV Group TDSIC Project(s), and the Fund shall continue until fully disbursed for RV Group TDSIC Project(s).

Addendum B

9) RV Group TDSIC Project(s) shall include any-and-all projects that qualify under the TDSIC Statute. NIPSCO will file for approval of the RV Group TDSIC Project(s) to allow the RV Group TDSIC Projects to include as many qualifying types of projects as possible, including: (i) RV Group operation or production facility updates or expansions that will result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support of RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. To the extent that a project proposed by an RV Group member does not qualify under the TDSIC Statute but would qualify under NIPSCO's demand side management ("DSM") tracker, NIPSCO will seek inclusion of qualifying projects in the DSM tracker, and these projects would not count against the $3.5 million total RV Group TDSIC Project amount.

10) Each of the RV Group members shall be entitled to request one or more RV Group TDSIC Project(s) subject to the review and support of NIPSCO, which support and approval shall not be unreasonably withheld or delayed. Any requests to support RV Group TDSIC Project(s) from the Fund will be presented in a tracker filing by NIPSCO in Cause No. 45557-TDSIC-X (or successor docket), which will require and provide a sufficient evidentiary showing consistent with the TDSIC Statute for the approval of such amounts.

11) Notwithstanding the provisions of paragraph B.13 of the Stipulation and Settlement Agreement, all other participating parties in the then-pending TDSIC docket shall be provided notice of and reserve the right to timely take any position on such RV Group TDSIC Project(s) funding request when the request is formally presented in the TDSIC tracker filing.

12) NIPSCO and the RV Group shall work together in good faith to establish precise administrative details for applications or requests for RV Group TDSIC Project(s), and such applications or requests can be made any time after approval of the Settlement Agreement, consistent with the language and requirements herein.

ACCEPTED AND AGREED this 10th day of March, 2023.

[SIGNATURE PAGES FOLLOW]

Addendum B

Northern Indiana Public Service Company LLC

Erin A. Whitehead

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Attachment A

RV Industry User's Group

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
STEAM PRODUCTION PLANT									
311.00 STRUCTURES AND IMPROVEMENTS									
MICHIGAN CITY GENERATING STATION	12-2026	110-R2.5 *	(8)	51,562,435.54	17,998,984	37,688,446	3,589,376 **	6.96	10.5
MICHIGAN CITY - UNIT 12	12-2026	110-R2.5 *	(8)	105,612,033.98	34,465,564	79,595,433	7,580,517 **	7.18	10.5
R M SCHAHFER GENERATING STATION	12-2025	110-R2.5 *	(11)	127,915,344.56	46,961,777	95,024,255	9,049,929 **	7.07	10.5
R M SCHAHFER - UNIT 14	12-2021	110-R2.5 *	(11)	7,254,940.91	8,052,984	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	110-R2.5 *	(11)	8,973,687.98	9,960,794	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	110-R2.5 *	(11)	142,375,381.48	59,259,829	98,776,845	9,407,319 **	6.61	10.5
R M SCHAHFER - UNIT 18	12-2025	110-R2.5 *	(11)	66,503,875.56	27,117,452	46,701,850	4,447,795 **	6.69	10.5
SUGAR CREEK	06-2068	110-R2.5 *	(20)	8,313,732.16	971,170	9,005,309	209,207	2.52	43.0
TOTAL ACCOUNT 311				518,511,432.17	204,788,554	366,792,138	34,284,143	6.61	10.7
BOILER PLANT EQUIPMENT									
312.10 BOILER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2026	55-S0 *	(8)	113,680,109.39	41,230,199	81,544,319	7,766,126 **	6.83	10.5
MICHIGAN CITY - UNIT 12	12-2026	55-S0 *	(8)	228,859,600.56	75,477,700	171,690,669	16,351,492 **	7.14	10.5
R M SCHAHFER GENERATING STATION	12-2025	55-S0 *	(11)	84,292,339.39	26,568,061	66,996,436	6,380,613 **	7.57	10.5
R M SCHAHFER - UNIT 14	12-2021	55-S0 *	(11)	49,723,376.18	55,192,948	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	55-S0 *	(11)	33,603,926.03	37,300,358	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	55-S0 *	(11)	202,359,699.26	79,151,905	145,467,361	13,854,034 **	6.85	10.5
R M SCHAHFER - UNIT 18	12-2025	55-S0 *	(11)	201,099,271.43	79,004,423	144,215,768	13,734,835 **	6.83	10.5
SUGAR CREEK	06-2068	55-S0 *	(20)	94,097,828.91	11,111,311	101,806,084	2,971,726	3.16	34.3
TOTAL ACCOUNT 312.1				1,007,716,151.15	405,036,905	711,720,637	61,058,826	6.06	11.7
312.20 BOILER PLANT - MOBILE FUEL HDLG/STRG									
MICHIGAN CITY GENERATING STATION	12-2026	55-S0 *	(8)	8,288,460.63	3,366,998	5,584,539	531,861 **	6.42	10.5
MICHIGAN CITY - UNIT 12	12-2026	55-S0 *	(8)	798,597.22	334,235	528,250	50,310 **	6.30	10.5
R M SCHAHFER GENERATING STATION	12-2025	55-S0 *	(11)	17,364,935.22	7,709,401	11,565,677	1,101,493 **	6.34	10.5
TOTAL ACCOUNT 312.2				26,451,993.07	11,410,634	17,678,466	1,683,664	6.36	10.5
312.30 BOILER PLANT - UNIT TRAIN COAL CARS									
R M SCHAHFER GENERATING STATION		25-R2.5	0	1,443,972.95	148,395	1,295,578	123,388 **	8.55	10.5
312.40 BOILER PLANT - SO2 PLANT EQUIPMENT									
MICHIGAN CITY - UNIT 12	12-2026	55-S0 *	(8)	215,728,527.65	70,548,260	162,438,550	15,470,338 **	7.17	10.5
R M SCHAHFER GENERATING STATION	12-2025	55-S0 *	(11)	17,157,480.64	4,299,910	14,744,894	1,404,276 **	8.18	10.5
R M SCHAHFER - UNIT 14	12-2021	55-S0 *	(11)	6,435,509.61	7,143,416	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	55-S0 *	(11)	23,150,634.50	25,697,204	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	55-S0 *	(11)	77,536,922.09	33,963,354	52,102,630	4,962,155 **	6.40	10.5
R M SCHAHFER - UNIT 18	12-2025	55-S0 *	(11)	67,825,904.31	29,937,648	45,349,106	4,318,962 **	6.37	10.5
TOTAL ACCOUNT 312.4				407,834,978.80	171,589,792	274,635,180	26,155,731	6.41	10.5
312.50 BOILER PLANT - COAL PILE BASE									
MICHIGAN CITY GENERATING STATION	12-2026	55-S0 *	(8)	785,602.93	204,909	643,542	61,290 **	7.80	10.5
R M SCHAHFER - UNIT 17	12-2025	55-S0 *	(11)	1,200,088.24	373,831	958,267	91,264 **	7.60	10.5
R M SCHAHFER - UNIT 18	12-2025	55-S0 *	(11)	1,300,434.47	380,372	1,063,110	101,249 **	7.79	10.5
TOTAL ACCOUNT 312.5				3,286,125.64	959,112	2,664,919	253,803	7.72	10.5
TOTAL ACCOUNT 312				1,446,733,221.61	589,144,838	1,007,994,780	89,275,412	6.17	11.3

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
314.00 TURBOGENERATOR UNITS									
MICHIGAN CITY GENERATING STATION	12-2026	60-R2 *	(8)	1,514,710.15	648,262	987,625	94,060 **	6.21	10.5
MICHIGAN CITY - UNIT 12	12-2026	60-R2 *	(8)	97,603,289.17	36,747,168	68,664,384	6,539,465 **	6.70	10.5
R M SCHAHFER GENERATING STATION	12-2025	60-R2 *	(11)	13,617,782.83	3,142,627	11,973,112	1,140,296 **	8.37	10.5
R M SCHAHFER - UNIT 14	12-2021	60-R2 *	(11)	8,274,048.05	9,184,193	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	60-R2 *	(11)	14,130,188.82	15,684,510	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	60-R2 *	(11)	90,517,413.20	40,128,783	60,345,546	5,747,195 **	6.35	10.5
R M SCHAHFER - UNIT 18	12-2025	60-R2 *	(11)	96,892,278.80	43,225,441	64,324,988	6,126,189 **	6.32	10.5
SUGAR CREEK	06-2068	60-R2 *	(20)	57,667,038.75	7,987,309	61,213,138	1,633,121	2.83	37.5
TOTAL ACCOUNT 314				380,216,749.77	156,748,293	267,508,793	21,280,326	5.60	12.6
315.00 ACCESSORY ELECTRIC EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2026	65-R2 *	(8)	21,500,009.21	8,546,659	14,673,351	1,397,462 **	6.50	10.5
MICHIGAN CITY - UNIT 12	12-2026	65-R2 *	(8)	34,628,826.77	13,580,638	23,818,495	2,268,428 **	6.55	10.5
R M SCHAHFER GENERATING STATION	12-2025	65-R2 *	(11)	37,502,905.33	14,894,836	26,733,389	2,546,037 **	6.79	10.5
R M SCHAHFER - UNIT 14	12-2021	65-R2 *	(11)	9,152,749.82	10,159,552	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	65-R2 *	(11)	6,314,514.56	7,009,111	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	65-R2 *	(11)	61,137,859.51	27,246,983	40,616,041	3,868,194 **	6.33	10.5
R M SCHAHFER - UNIT 18	12-2025	65-R2 *	(11)	44,601,764.20	19,694,649	29,813,309	2,839,363 **	6.37	10.5
SUGAR CREEK	06-2068	65-R2 *	(20)	4,909,045.42	675,072	5,215,783	129,444	2.64	34.5
TOTAL ACCOUNT 315				219,747,674.82	101,807,500	140,870,368	13,048,928	5.94	10.8
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2026	70-R1.5 *	(8)	3,890,335.14	1,585,640	2,615,922	249,135 **	6.40	10.5
MICHIGAN CITY - UNIT 12	12-2026	70-R1.5 *	(8)	4,704,537.29	1,986,528	3,094,372	294,702 **	6.26	10.5
R M SCHAHFER GENERATING STATION	12-2025	70-R1.5 *	(11)	12,877,233.72	5,646,433	8,647,296	823,552 **	6.40	10.5
R M SCHAHFER - UNIT 14	12-2021	70-R1.5 *	(11)	981,904.75	1,089,914	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	70-R1.5 *	(11)	1,811,815.01	2,011,115	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	70-R1.5 *	(11)	6,188,369.28	2,960,268	3,908,822	372,269 **	6.02	10.5
R M SCHAHFER - UNIT 18	12-2025	70-R1.5 *	(11)	6,784,535.99	3,077,184	4,453,651	424,157 **	6.25	10.5
SUGAR CREEK	06-2068	70-R1.5 *	(20)	4,040,258.04	513,996	4,334,314	107,108	2.65	34.5
TOTAL ACCOUNT 316				41,278,989.22	18,871,078	27,054,377	2,270,923	5.50	11.9
TOTAL STEAM PRODUCTION PLANT				**2,606,488,067.59**	**1,071,360,263**	**1,810,220,456**	**160,159,732**	**6.14**	**11.3**
HYDRO PLANT									
331.00 STRUCTURES AND IMPROVEMENTS									
NORWAY GENERATING STATION	11-2037	70-S1 *	(8)	3,875,759.62	1,900,150	2,285,670	165,472	4.27	13.8
OAKDALE GENERATING STATION	11-2037	70-S1 *	(9)	7,088,825.05	3,699,663	4,027,156	291,896	4.12	13.8
TOTAL ACCOUNT 331				10,964,584.67	5,599,813	6,312,826	457,368	4.17	13.8
332.00 RESERVOIRS, DAMS AND WATERWAYS									
NORWAY GENERATING STATION	11-2037	85-R3 *	(6)	30,333,797.71	4,154,286	27,999,540	2,027,689	6.68	13.8
OAKDALE GENERATING STATION	11-2037	85-R3 *	(7)	18,896,329.12	3,286,661	16,932,411	1,227,369	6.50	13.8
TOTAL ACCOUNT 332				49,230,126.83	7,440,947	44,931,951	3,255,058	6.61	13.8
333.00 WATER WHEELS, TURBINES AND GENERATORS									
NORWAY GENERATING STATION	11-2037	75-R2 *	(6)	7,878,605.51	2,276,705	6,074,617	452,543	5.74	13.4
OAKDALE GENERATING STATION	11-2037	75-R2 *	(7)	6,495,122.48	2,345,036	4,604,745	339,831	5.23	13.6
TOTAL ACCOUNT 333				14,373,727.99	4,621,741	10,679,362	792,374	5.51	13.5

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
334.00 ACCESSORY ELECTRIC EQUIPMENT										
NORWAY GENERATING STATION	11-2037	55-L1.5	*	(6)	1,683,326.24	996,235	788,091	62,477	3.71	12.6
OAKDALE GENERATING STATION	11-2037	55-L1.5	*	(7)	839,479.23	325,734	572,509	43,145	5.14	13.3
TOTAL ACCOUNT 334					2,522,805.47	1,321,969	1,360,600	105,622	4.19	12.9
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT										
NORWAY GENERATING STATION	11-2037	55-S0.5	*	(6)	712,410.12	279,407	475,748	35,660	5.01	13.3
OAKDALE GENERATING STATION	11-2037	55-S0.5	*	(7)	124,968.62	58,674	75,042	5,718	4.58	13.1
TOTAL ACCOUNT 335					837,378.74	338,081	550,790	41,378	4.94	13.3
TOTAL HYDRO PLANT					**77,928,623.70**	**19,322,551**	**63,835,529**	**4,651,800**	**5.97**	**13.7**
OTHER PRODUCTION PLANT										
341.00 STRUCTURES AND IMPROVEMENTS										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S2.5	*	(6)	2,756,354.53	2,362,772	558,964	186,341	6.76	3.0
SUGAR CREEK	06-2048	50-S2.5	*	(7)	12,225,886.59	5,515,752	7,565,947	331,992	2.72	22.8
TOTAL ACCOUNT 341					14,982,241.12	7,878,524	8,124,911	518,333	3.46	15.7
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S2.5	*	(3)	5,957,207.32	4,892,674	1,243,250	426,632	7.16	2.9
R M SCHAHFER - UNIT 16A	12-2026	50-S2.5	*	(3)	2,214,317.98	2,009,097	271,651	94,810	4.28	2.9
R M SCHAHFER - UNIT 16B	12-2026	50-S2.5	*	(3)	1,297,414.52	1,172,659	163,678	56,636	4.37	2.9
SUGAR CREEK	06-2048	50-S2.5	*	(7)	3,207,124.87	1,250,406	2,181,218	95,845	2.99	22.8
TOTAL ACCOUNT 342					12,676,064.69	9,324,836	3,859,797	673,923	5.32	5.7
343.00 PRIME MOVERS										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-R1	*	(3)	5,848,700.80	5,093,148	931,014	312,421	5.34	3.0
R M SCHAHFER - UNIT 16A	12-2026	50-R1	*	(3)	9,551,195.57	9,837,731	0	0	-	-
R M SCHAHFER - UNIT 16B	12-2026	50-R1	*	(3)	23,070,301.52	23,762,411	0	0	-	-
SUGAR CREEK	06-2048	50-R1	*	(7)	76,761,262.31	45,015,641	37,118,910	1,679,517	2.19	22.1
TOTAL ACCOUNT 343					115,231,460.20	83,708,931	38,049,924	1,991,938	1.73	19.1
344.00 GENERATORS										
R M SCHAHFER - UNIT 16A	12-2026	55-R3	*	(3)	6,625,784.57	6,750,067	74,491	24,830	0.37	3.0
R M SCHAHFER - UNIT 16B	12-2026	55-R3	*	(3)	2,538,171.36	2,614,317	0	0	-	-
SUGAR CREEK	06-2048	55-R3	*	(7)	40,547,004.58	22,021,609	21,363,686	916,140	2.26	23.3
TOTAL ACCOUNT 344					49,710,960.51	31,385,993	21,438,177	940,970	1.89	22.8
344.10 GENERATORS - SOLAR		20-S2.5		0	1,014,483.69	158,330	856,154	54,318	5.35	15.8
345.00 ACCESSORY ELECTRIC EQUIPMENT										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S1	*	(3)	18,757,510.34	12,325,414	6,994,822	2,331,607	12.43	3.0
R M SCHAHFER - UNIT 16A	12-2026	50-S1	*	(3)	759,938.06	782,736	0	0	-	-
R M SCHAHFER - UNIT 16B	12-2026	50-S1	*	(3)	1,308,789.12	1,146,136	201,917	67,492	5.16	3.0
SUGAR CREEK	06-2048	50-S1	*	(7)	34,611,832.01	16,241,859	20,792,801	962,059	2.78	21.6
TOTAL ACCOUNT 345					55,438,069.53	30,496,145	27,989,540	3,361,158	6.06	8.3
345.10 ACCESSORY ELECTRIC EQUIPMENT - SOLAR		20-S2.5		0	253,620.96	24,542	229,079	14,545	5.73	15.7
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-R2.5	*	(3)	533,483.87	415,811	133,677	44,695	8.38	3.0
SUGAR CREEK	06-2048	55-R2.5	*	(7)	5,645,982.05	2,628,663	3,412,538	147,133	2.61	23.2
TOTAL ACCOUNT 346					6,179,465.92	3,044,474	3,546,215	191,828	3.10	18.5
TOTAL OTHER PRODUCTION PLANT					**255,486,366.62**	**166,021,775**	**104,093,797**	**7,747,013**	**3.03**	**13.4**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
TRANSMISSION PLANT									
350.20 LAND RIGHTS		75-R4	0	76,903,948.43	12,972,050	63,931,898	978,912	1.27	65.3
352.00 STRUCTURES AND IMPROVEMENTS		65-R1.5	(15)	88,052,012.25	34,893,524	66,366,290	1,197,600	1.36	55.4
353.00 STATION EQUIPMENT		52-S0	(10)	1,067,060,113.72	317,158,359	856,607,766	19,585,588	1.84	43.7
354.00 TOWERS AND FIXTURES		75-R4	(26)	168,314,495.66	88,418,562	123,657,703	2,114,910	1.26	58.5
355.00 POLES AND FIXTURES		62-R1	(35)	551,560,826.90	123,239,073	621,368,043	11,050,658	2.00	56.2
356.00 OVERHEAD CONDUCTORS AND DEVICES		68-R2	(40)	337,965,006.34	120,216,178	352,934,831	6,143,370	1.82	57.4
357.00 UNDERGROUND CONDUIT		65-S4	(5)	899,342.12	683,182	261,127	5,535	0.62	47.2
358.00 UNDERGROUND CONDUCTORS AND DEVICES		50-R1.5	(5)	3,852,252.26	1,141,758	2,903,107	69,101	1.79	42.0
359.00 ROADS AND TRAILS		70-R4	0	92,216.26	66,932	25,284	518	0.56	48.8
TOTAL TRANSMISSION PLANT				**2,294,700,213.94**	**698,789,618**	**2,088,056,049**	**41,146,192**	**1.79**	**50.7**
DISTRIBUTION PLANT									
360.20 LAND RIGHTS		75-R4	0	1,375,975.22	344,386	1,031,589	17,316	1.26	59.6
361.00 STRUCTURES AND IMPROVEMENTS		65-R1.5	(15)	16,828,466.07	9,240,468	10,112,268	207,264	1.23	48.8
362.00 STATION EQUIPMENT		50-R1.5	(10)	552,738,200.47	156,218,958	451,793,063	10,950,881	1.98	41.3
POLES, TOWERS AND FIXTURES									
364.10 CUSTOMER TRANSFORMER STATION		50-S0	(53)	56,866,138.03	35,150,210	51,854,981	1,257,621	2.21	41.2
364.20 POLES, TOWERS, AND FIXTURES		47-R1	(53)	615,333,057.72	236,009,428	705,450,150	17,833,830	2.90	39.6
TOTAL ACCOUNT 364				672,199,195.75	271,159,638	757,305,131	19,091,451	2.84	39.7
365.00 OVERHEAD CONDUCTORS AND DEVICES		65-R1	(60)	387,401,111.79	211,552,607	408,289,172	7,039,581	1.82	58.0
366.00 UNDERGROUND CONDUIT		70-S2.5	(5)	5,967,002.86	2,122,084	4,143,269	82,232	1.38	50.4
367.00 UNDERGROUND CONDUCTORS AND DEVICES		52-R2	(30)	588,030,774.37	186,422,843	578,017,164	13,515,573	2.30	42.8
368.00 LINE TRANSFORMERS		47-S0	(8)	377,676,754.42	147,885,750	260,005,145	7,044,886	1.87	36.9
SERVICES									
369.10 OVERHEAD SERVICES		47-R1	(32)	55,052,985.58	41,384,977	31,284,964	755,111	1.37	41.4
369.20 UNDERGROUND SERVICES		70-R3	(32)	279,915,670.17	145,725,175	223,763,510	3,726,848	1.33	60.0
TOTAL ACCOUNT 369				334,968,655.75	187,110,152	255,048,474	4,481,959	1.34	56.9
METERS									
370.10 CUSTOMER METERING STATIONS		50-R2	(2)	23,846,960.51	10,150,092	14,173,808	350,253	1.47	40.5
370.20 METERS		24-L0	(2)	75,930,087.87	27,902,929	49,545,761	2,674,608	3.52	18.5
TOTAL ACCOUNT 370				99,777,048.38	38,053,021	63,719,569	3,024,861	3.03	21.1
371.00 INSTALLATIONS ON CUSTOMER PREMISES		20-O1	(25)	10,463,918.32	6,950,349	6,129,549	371,739	3.55	16.5
373.00 STREET LIGHTING AND SIGNAL SYSTEMS		31-L0	(30)	64,108,114.54	28,551,926	54,788,623	2,146,236	3.35	25.5
TOTAL DISTRIBUTION PLANT				**3,111,535,217.94**	**1,245,612,182**	**2,850,383,016**	**67,973,979**	**2.18**	**41.9**
GENERAL PLANT									
390.00 STRUCTURES AND IMPROVEMENTS		55-R1.5	(10)	24,312,639.07	11,777,969	14,965,934	347,085	1.43	43.1
391.10 OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	4,764,626.59	2,893,068	1,871,559	181,862	3.82	10.3
391.20 COMPUTERS AND PERIPHERAL EQUIPMENT		7-SQ	0	21,803,108.62	12,136,913	9,666,196	3,397,605	15.58	2.8
393.00 STORES EQUIPMENT		30-SQ	0	984,845.25	696,376	288,469	14,420	1.46	20.0
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	28,427,977.49	10,606,283	17,821,694	1,087,549	3.83	16.4
395.00 LABORATORY EQUIPMENT		20-SQ	0	6,802,019.90	4,781,618	2,020,402	140,524	2.07	14.4
397.00 COMMUNICATION EQUIPMENT		15-SQ	0	38,827,784.66	7,867,197	30,960,588	3,382,628	8.71	9.2
398.00 MISCELLANEOUS EQUIPMENT		20-SQ	0	3,856,492.07	1,444,057	2,412,435	200,326	5.19	12.0
TOTAL GENERAL PLANT				**129,779,493.65**	**52,203,481**	**80,007,277**	**8,751,999**	**6.74**	**9.1**
ACCOUNT 391.2 RESERVE AMORTIZATION					9,600,000		(3,200,000)	***	3.0
TOTAL DEPRECIABLE ELECTRIC PLANT				**8,475,917,983.44**	**3,262,909,870**	**6,996,596,124**	**287,230,715**	**3.39**	**24.4**

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
NONDEPRECIABLE									
302.00 FRANCHISES AND CONSENTS				1,640.54	(33)				
303.00 MISCELLANEOUS INTANGIBLE PLANT				92,059,173.58	62,686,927				
310.00 LAND AND LAND RIGHTS				5,309,536.16	(21,577)				
311.00 STRUCTURES AND IMPROVEMENTS									
D H MITCHELL GENERATING STATION					4,481,692				
312.10 BOILER PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION					2,821,855				
312.30 BOILER PLANT - UNIT TRAIN COAL CARS									
BAILLY GENERATING STATION				2,701,500.27					
312.50 BOILER PLANT - COAL PILE BASE									
D H MITCHELL GENERATING STATION					69,620				
314.00 TURBO-GENERATOR UNITS									
D H MITCHELL GENERATING STATION					3,298,615				
315.00 ACCESSORY ELECTRIC EQUIPMENT									
D H MITCHELL GENERATING STATION					(2,570,344)				
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION					(1,224,757)				
330.00 LAND AND LAND RIGHTS				24,812.88	(221)				
340.20 LAND RIGHTS				1,126,899.78	(12,219)				
350.10 LAND				20,549,229.10	(180,923)				
360.10 LAND				4,102,199.55	(87,026)				
389.10 LAND				16,939.41	(12)				
389.20 LAND RIGHTS				120,527.51	(2,489)				
390.20 LEASED PROPERTY				252,224.97	156,664				
ACCOUNTS NOT STUDIED									
TRANSPORTATION EQUIPMENT									
392.20 TRANSPORTATION EQUIPMENT - TRAILERS				1,675,172.99	902,824				
392.30 TRANSPORTATION EQUIPMENT - TRUCKS < 13,000				388,177.16	39,318				
392.40 TRANSPORTATION EQUIPMENT - TRUCKS > 13,000				454,874.49	786,940				
396.00 POWER OPERATED EQUIPMENT				6,093,725.82	4,902,444				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				134,876,634.23	76,047,298				
TOTAL ELECTRIC PLANT				8,610,794,617.67	3,338,957,168				

* INTERIM SURVIVOR CURVES USED. EACH LOCATION HAS A UNIQUE PROBABLE RETIREMENT DATE.

** ANNUAL ACCRUAL AMOUNT IS BASED ON 11 YEAR REMAINING LIFE.

*** SEPARATE RESERVE AMORTIZATION TO BE RECOVERED OVER 5 YEARS BEGINNING IN 2021.

STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831/531 MODIFICATION

This Stipulation and Settlement Agreement on Rate 831/531 Modification (the "Agreement")[1] is entered into this 12th day of September, 2022, by and among Northern Indiana Public Service Company LLC ("NIPSCO") and the NIPSCO Industrial Group;[2] NLMK Indiana; Pratt Paper (IN), LLC; and United States Steel Corporation (collectively the "Rate 831 Customers," and with NIPSCO, the "Rate 831 Settling Parties"), who stipulate and agree for purposes of settling issues related to Rate 831 to be presented in NIPSCO's forthcoming general rate case proceeding, that the terms and conditions set forth below represent a fair and reasonable resolution of all issues related to the Rate 831 Settling Parties' modification of Rate 831 in the electric rate case proceeding NIPSCO intends to file in September of 2022, subject to the terms of Section B.6.

This Agreement sets forth NIPSCO's modified Alternative Regulatory Plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 for Rate 831 Modification, which NIPSCO intends to file as part of its case-in-chief in its upcoming rate proceeding. The Rate

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1 The current NIPSCO electric tariff rate schedule under which the customers who are signatories to this Agreement currently take service is Rate 831. The successor rate schedule proposed by NIPSCO in the forthcoming base rate case proceeding will be designated Rate 531. For sake of clarity, throughout this Agreement, "Rate 831" and "Rate 831 customers" is used consistently throughout to refer to both the current and proposed tariff rate and customers, except where necessary to distinguish between the current Rate 831 and the proposed Rate 531.

2 For purposes of this Agreement, the NIPSCO Industrial Group is comprised of Cleveland-Cliffs Steel LLC, Linde, Inc., BP Products North America, Inc., and Cargill, Inc.

831 Settling Parties stipulate and agree to NIPSCO's modified ARP and agree to file testimony in the upcoming rate proceeding or otherwise affirmatively support the ARP and the terms of this Agreement. The terms and obligations set forth in this Agreement are conditioned on approval of the ARP and incorporation of this Agreement into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without material modification, change or conditioning term that is unacceptable to any of the Rate 831 Settling Parties at the conclusion of the rate proceeding.

A. Background

WHEREAS, NIPSCO filed a Verified Petition initiating Cause No. 45159 on October 31, 2018 requesting, among other relief, approval of an ARP pursuant to Indiana Code § 8-1-2.5-6 that would facilitate a new service structure for industrial rates (Rate 831) to address a changing energy landscape;

WHEREAS, in Cause No. 45159, NIPSCO filed testimony explaining the operation of Rate 831 and supporting the need for Rate 831 to address the loss of industrial load, provide a more competitive rate structure for large industrial customers, and promote effective system planning as NIPSCO transitions its generation resources;

WHEREAS, in Cause No. 45159, NIPSCO and prospective Rate 831 customers reached a mutual agreement on issues related to Rate 831 (collectively, the "45159

Rate 831 Settling Parties") and such agreement was memorialized in a Stipulation and Settlement Agreement filed with the Commission on May 17, 2019 (the "831 Implementation Agreement"). The 831 Implementation Agreement was ultimately approved by the Commission in its Final Order dated December 4, 2019. The 831 Implementation Agreement and supporting testimony also called for approval of the cost of service study and allocation methodology presented by NIPSCO, as modified on rebuttal;

WHEREAS, in Cause No. 45159, the Commission approved the allocation of production costs using the 4 Coincident Peak ("4 CP") method, consistent with NIPSCO's system load characteristics and the design and operation of NIPSCO's system;

WHEREAS, under the terms of Rule 5.8 of NIPSCO's electric tariff as approved by the Commission in Cause No. 45159, the existing Rate 831 service contracts would terminate upon the approval of new base rates, and upon such termination all Rate 831 customers could potentially reduce their level of Tier 1 firm contract demand down to the tariff minimum of 10 MW each, or 70 MW in total;

WHEREAS, in order to reduce the contested issues in NIPSCO's upcoming rate proceeding, the Rate 831 Settling Parties negotiated in advance of NIPSCO's filing and have reached mutual agreement on issues related to Rate 831 (which will be renumbered Rate 531) for purposes of that cause. The Settling Parties' agreement with respect to the Rate 831 issues to be presented in that cause is set forth in this Agreement, and it is the intent of the Rate 831 Settling Parties to file testimony supporting this Agreement as part of NIPSCO's upcoming rate proceeding; and

WHEREAS, the Rate 831 Settling Parties request Commission approval of NIPSCO's modified ARP and this Agreement in its entirety, without material change or modification unacceptable to any of the Rate 831 Settling Parties, and incorporation of this Agreement in its Final Order in NIPSCO's upcoming rate proceeding;

NOW, THEREFORE, the Rate 831 Settling Parties agree to the following:

B. Settlement Terms

1. Scope of this Agreement:

The scope of this Agreement is limited to the Rate 831 Settling Parties' mutual agreement and understanding with respect to the modification of NIPSCO's ARP to reflect changes in allocation of costs between Rate 831 and Rate 531, including the use and approval of a 4 CP cost of service methodology for the allocation of production demand-related costs and a 12 CP cost of service methodology for the allocation of transmission demand-related cost, the agreed level of Tier 1 contract demand by the Rate 831 customers, the resulting design of rates for new Rate 531, and those other items expressly stated herein. Except as expressly stated herein, this Agreement does not provide for any further modifications to NIPSCO's ARP approved in Cause No. 45159 nor modifications to the existing Rate 831 tariff. The Rate 831 Settling Parties reserve all rights with respect to issues and positions not addressed in this Agreement, including, but not limited to, NIPSCO's revenue requirement, NIPSCO's proposals for modifications to the new Rate 531 tariff set forth in Section B.6. of this Agreement, non-Rate 831 or 531 specific rate proposals, and adjustments to NIPSCO's as-filed allocated cost of service study, provided that any such proposed adjustments to the allocated cost of service study do not propose alteration of the use of the 4 CP demand related production or 12 CP demand related transmission allocation methodologies.

2. Allocation:

a. The Rate 831 Settling Parties agree that NIPSCO's allocated cost of service methodology to be filed in the upcoming rate proceeding will be based upon the 4 CP method for production demand-related costs.[3] The Rate 831 Settling Parties agree that

[3] The 4 CP methodology uses the summer months of June, July, August and September to calculate the coincident peak demand allocation factors for purposes of allocating demand-related costs associated with production functions.

the 4 CP cost of service study should be used to allocate costs to Rate 831 as a class based on a Rate 831 Tier 1 subscription of 180 megawatts. Each of the Rate 831 Customers agrees to execute a new contract for Tier 1 demand subscription under Rate 831 as set forth in Confidential Attachment A to this Agreement for the contract term set forth in Section B.3.a. of this Agreement. The production demand-related cost of service shall be allocated to Rate 831 using 180 megawatts, and rates shall be designed for Rate 831 using the contracted Tier 1 demand levels totaling 170 megawatts. The Rate 831 Settling Parties agree to the allocation of tracker costs to Rate 831 Customers as set forth in Attachment B to this Agreement and further agree that only Rate 831/531 Customers' Tier 1 commitments constitute "firm load" for purposes of any transmission, distribution, and storage system improvement charge ("TDSIC") expenditures and costs, and that the TDSIC revenue allocation shall be applied only to revenue associated with Rate 831 Customers' Tier 1 contract demand.

b. The 831 Settling Parties recognize and understand that the Tier 1 contract demands as set forth in Section B.2.a. of this

Agreement will be binding only through the end of the Contract Term as set forth below. This Agreement does not bind the Rate 831 Customers beyond that term, and NIPSCO's new Rate 531 tariff and rules will be adjusted to reflect such term.

c. As part of the agreement to allocate 180 megawatts of production demand related costs to Rate 831 and the Tier 1 contract demand commitments established for purposes of the upcoming rate proceeding, the Rate 831 Customers shall retain future flexibility to adjust Tier 1 levels consistent with the terms of the existing tariff. For purposes of the upcoming rate proceeding, the 831 Settling Parties recognize that the agreed demand level for cost allocation purposes exceeds the committed level of actual contract demand, and that this approach allocates costs to the Rate 831 class in excess of the cost of service based on Tier 1 commitments but moves the overall allocation closer to cost of service than is provided under current rates. The Rate 831 Settling Parties agree that in future rate proceedings the cost allocation to Rate 831 (and any successor rate) will continue to move the class toward the actual cost of service based on actual contract demands.

d. Prior to the earlier of the commencement of a future rate case or the contract termination date, NIPSCO and Rate 831 Customers agree to meet and negotiate in good faith to establish new class demand allocation and Tier 1 contract demand levels for the subsequent period, recognizing that further reductions in both the class allocation and Tier 1 commitments will be expected at that time.

3. Contract Term:

a. Existing Rate 831 Customers. With respect to existing Rate 831 Customers, the expiration of the term of any contract entered into for purposes of receiving service under the new Rate 531 shall be the earlier of: (1) the effective date for new rates under NIPSCO's next electric rate case filing after the rate case to be filed in September of 2022; or (2) May 31, 2026. The commitments set forth in this Agreement and any contract entered into for purposes of receiving service under the new Rate 531 shall be binding only through the end of the Contract Term.

b. Rate 831 Increases in Tier 1 Demand. Any existing Rate 831 customer, or new Rate 531 customer, may increase Tier 1 firm contract demand or begin taking service under new Rate 531 in accordance with the existing Rate 831 tariff terms.

4. Tracker Allocations:

a. The Rate 831 Settling Parties agree that allocation factors for NIPSCO's existing and proposed tracker mechanisms shall be developed in a manner consistent with Exhibit A to the 831 Implementation Agreement as modified by this Agreement, the cost of service methodology and rate design as agreed herein, and the revenue requirement as approved by the Commission.

b. The Rate 831 Settling Parties agree that the Rate 831/531 Modification – Exhibit B, attached hereto, sets out the applicable portions of Rate 531 that are subject to each existing tracker mechanism.

c. For the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that the allocation factors for TDSIC purposes shall be developed in a manner consistent with Exhibit A to the 831 Implementation

Agreement as modified by this Agreement, the cost of service methodology and rate design as agreed herein, and the revenue requirement as approved by the Commission.

5. Rate 831 Rate Design:

a. Except as otherwise provided herein, the Rate 831 Settling Parties agree that Rate 831 shall be modified and adopted as proposed in NIPSCO's ARP as set forth in this Agreement and based on the revenue requirement that is ultimately approved in the upcoming rate case to be filed by NIPSCO.

b. The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the 4 CP method for production–related demand cost of service methodology. The Tier 1 demand commitments set forth in Rate 831/531 Modification - Confidential Exhibit A are contingent on approval of said cost of service study, and absent such approval shall not be binding on Rate 831 customers.

c. For purposes of transmission demand-related costs, the Rate 831 Settling Parties agree that the design of Rate 831 should be based on the 12 CP cost of service methodology to be presented by NIPSCO in its case-in-chief filed in its upcoming rate case.

d. For purposes of the "Adjacent Affiliate Qualified Facility Premise Transmission Charge," the Rate 831 Settling Parties agree that the terms of the existing Rate 831 tariff shall remain in effect.

e. The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the existing Rate 831 customers and their corresponding Rate 831 Tier 1 energy is set forth in Rate 831/531 Modification – Confidential Exhibit A, attached hereto. The Rate 831 Settling Parties agree that the Tier 1 subscriptions reflected in Rate 831/531 Modification – Confidential Exhibit A shall be binding upon each customer for the contract term, except as provided for in this Agreement and under the terms of NIPSCO's electric tariff.

6. Tariff Language:

The Rate 831 Settling Parties agree that the terms of this Agreement do not require any change or modification to the existing provisions of the Rate 831 tariff, except as expressly provided herein. NIPSCO has discussed two potential changes to existing Rate 831 beyond those presented in this Agreement, which relate to good faith efforts to provide updated load forecasts and potential modifications to reference MISO's proposed seasonal resource adequacy construct. However, as set forth in Section B.1. above, those provisions are outside the scope of this Agreement. Therefore, NIPSCO reserves the right to propose changes consistent with these two items, and the Rate 831 Settling Parties reserve the right to take any position with respect to these two items, and only these two items. In all other respects, the terms and provisions of the Rate 831 tariff shall be maintained intact in the new Rate 531, except as described herein.

C. Procedural Aspects and Presentation of the Agreement

1. The Rate 831 Settling Parties have spent considerable and valuable time reviewing data and negotiating the Agreement in an effort to resolve potentially contested issues in NIPSCO's upcoming rate case and to avoid time consuming and costly litigation. The Rate 831 Settling Parties will request that the Commission review this Agreement as part of NIPSCO's modification of its ARP in the upcoming rate case, and approve said modification to the ARP and incorporate the terms of this Agreement into its Final Order issued in that cause, in its entirety and without material modification or condition unacceptable to any of the Rate 831 Settling Parties. To the extent the Commission makes material change or modification to this Agreement that is unacceptable to one or more of the Rate 831 Settling Parties, or otherwise does not approve this Agreement, the Rate 831 Settling Parties acknowledge that NIPSCO will be

required to make a subsequent filing consistent with the Commission's Final Order before it can implement rates for any customer class. In the event such an order includes a material change or modification, each of the Rate 831 Settling Parties shall notify all other Rate 831 Settling Parties in writing within 5 days of issuance whether such change or modification is acceptable. Further, if an order does not approve this Agreement or makes an unacceptable change or modification, and absent further agreement among the Rate 831 Settling Parties to the contrary, each of the Rate 831 customers shall, within 10 days of issuance, provide to NIPSCO in writing (a) their new level of Tier 1 firm demand, which shall be no less than 10 megawatts, or (b) for any Rate 831 customer who chooses to take service under any other rate schedule, the rate schedule under which they are electing to take service. The Rate 831 Settling Parties shall also proceed promptly with good faith negotiations in accordance with Section C.3. NIPSCO shall retain all rights and options available by law with respect to compliance filings or other measures associated with the implementation of approved rates, and each of the Rate 831 Settling Parties shall retain all rights and options available by law to seek rehearing, commence an appeal or otherwise pursue relief relating to such order.

a. For purposes of this Agreement, a material modification includes, but is not limited to, a modification to (i) production demand-related cost of service using 180 megawatts or rates designed using the contracted Tier 1 demand levels totaling 170 megawatts; (ii) the agreed-to contract term; (iii) 4 CP cost of service methodology for production-related demand-related cost; and (iv) 12 CP cost of service methodology for the allocation of transmission demand-related cost.

2. The Rate 831 Settling Parties agree to assist and cooperate in the preparation and presentation of testimony in support of NIPSCO's proposed ARP and this Agreement, in order to provide an appropriate factual basis for the Commission to implement NIPSCO's modified ARP and this Agreement into its Final Order.

3. The concurrence of the Rate 831 Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's continued approval of the 4 CP methodology for the allocation of production demand-related costs and 12 CP methodology for the allocation of transmission demand-related costs as set forth in NIPSCO's allocated cost of service study to be filed in its upcoming rate case. In the event the 4 CP methodology for purposes of allocating production demand-related costs or the 12 CP methodology for purposes of allocating transmission demand-related costs is not approved by Commission, or any other material modification is made to this Agreement that is unacceptable to one or more of the Rate 831 Settling Parties, the Rate 831 Settling Parties agree to meet promptly and to negotiate in good faith to reach a new agreement determining the

allocation and contractual demand for such purposes, or otherwise revising the structure, design or terms of the rate schedule or schedules under which Rate 831 customers take service, and shall submit such agreement to the Commission within thirty (30) days of the date of the Commission Order.

4. The Rate 831 Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. Except as expressly discussed herein, the Rate 831 Settling Parties agree that a Final Order approving this Agreement shall not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise and each of the Rate 831 Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense. If the terms of this Agreement are not approved by the Commission as part of its Final Order, the Rate 831 Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding.

5. The Rate 831 Settling Parties stipulate that the evidence of record to be presented in NIPSCO's upcoming rate case will constitute substantial evidence sufficient to support the modification to NIPSCO's ARP and this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for incorporation of this Agreement into the Commission's Final Order. The Rate 831 Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

6. The Rate 831 Settling Parties shall not appeal the Final Order or any subsequent Commission order as to any portion of such order that is specifically approving or implementing the provisions of this Agreement and NIPSCO's modified ARP without material modification or condition unacceptable to any of the Rate 831 Settling Parties; and the Rate 831 Settling Parties shall oppose any appeal of any portion of the Final Order approving this Agreement and NIPSCO's modified ARP.

7. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Rate 831 Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

8. The provisions of this Agreement shall be enforceable by any Rate 831 Settling Party before the Commission or in any court of competent jurisdiction.

9. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 12th day of September, 2022.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Erin E. Whitehead

NIPSCO Industrial Group

____

NLMK INDIANA

Nicholas Thomas

Nicholas Thomas 9.9.22

Attachment C

United States Steel Corporation

Kristina Kern Wheeler

Confidential - Excluded from public access per A.R. 9(G)

Pratt Paper (IN), LLC

Stephen Ward
Chief Financial Officer

Northern Indiana Public Service Company LLC
Modification Agreement Confidential Exhibit A

Customer	Contract Demand (MW)
[redacted]	
Total	170.0

Rate 831/531 Modification Agreement Exhibit B

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 15
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 570	FAC	Adjustment of Charges for Cost of Fuel Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 571	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1 and Tier 2, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 574	RA	Adjustment of Charges for Resource Adequacy	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 576	BMTIS	Back-Up and Maintenance Industrial Service Rider	531
Rider 577	EDR	Economic Development Rider	524, 526, 532, 533
Rider 578	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541, 544,
Rider 579	IS	Interconnection Standards	511, 520, 521, 522, 523, 524, 525, 526, 531, 532, 533, 541, 544, 565
Rider 580	NM	Net Metering	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 15
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 581	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 582	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 583	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, 544, Rider 576
Rider 586	GPR	Green Power Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, and Rider 576
Rider 587	FMCA	Adjustment of Charges for Federally Mandated Costs	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 588	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 589	EDG	Excess Distributed Generation	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541
Rider 594		Adjustment of Charges for Variable Costs of Coal-Fired Generation	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 597		Universal Service Program (USP) Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576