ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR GAS UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ITS GAS PLANT IN SERVICE; (4) APPROVAL OF MECHANISM TO MODIFY RATES PROSPECTIVELY FOR CHANGES IN FEDERAL OR STATE INCOME TAX RATES, UTILITY RECEIPTS TAX RATES, AND PUBLIC UTILITY FEE RATES; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (6) AUTHORITY TO IMPLEMENT TEMPORARY RATES CONSISTENT WITH THE PROVISIONS OF IND. CODE § 8-1-2-42.7.

CAUSE NO. 45621

APPROVED: JUL 27 2022

ORDER OF THE COMMISSION

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

On September 29, 2021, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed its Verified Petition for General Rate Increase and Associated Relief under Ind. Code §§ 8-1-2-61 and 8-1-2-42.7, Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements, and Request for Administrative Notice ("Petition") with the Indiana Utility Regulatory Commission ("Commission"). In the Petition, NIPSCO requested: (1) authority to increase its retail rates and charges for gas utility service through the phase-in of rates; (2) approval of new schedules of rates and charges, general rules and regulations, and riders; (3) approval of revised depreciation rates applicable to its gas plant in service; (4) approval of a mechanism to modify rates prospectively for changes in federal or state income tax rates, utility receipts tax ("URT") rates, and public utility fee ("PUF") rates; (5) approval of accounting relief; and (6) authority to implement temporary rates.

In support of its Petition, NIPSCO filed testimony and attachments of the following witnesses:

- Michael W. Hooper, President and Chief Operating Officer for NIPSCO
- Erin Whitehead, Vice President of Regulatory Policy and Major Accounts for NIPSCO
- Jeffrey D. Newcomb, Manager, Regulatory – Rate Case Optimization for NiSource Corporate Services Company ("NCSC")
- Elizabeth A. Dousias, Manager of Regulatory for NCSC
- Angela Camp, Director of Regulatory and Utility Planning for NCSC

- Nick Bly, Manager of Corporate Consolidation in Financial Planning and Analysis for NCSC
- Gunnar J. Gode, Vice President and Chief Accounting Officer for NCSC
- Patrick L. Baryenbruch, President of Baryenbruch & Company, LLC
- Steven Sylvester, Vice President and General Manager for NIPSCO
- Rick Smith, Manager of Operations for NIPSCO
- Andrew Campbell, Director of Regulatory Support & Planning for NIPSCO
- Kimberly Cartella, Director of Compensation for NCSC
- John Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC
- Bryan Trapp, Director of Tax Planning and Controversy for NCSC
- Vincent V. Rea, Managing Director of Regulatory Finance Associates, LLC
- Melissa Bartos, Vice President at Concentric Energy Advisors
- Ronald J. Amen, Managing Partner with Atrium Economics, LLC
- Judith L. Siegler, Lead Regulatory Studies Analyst for NCSC

On September 29, 2021, NIPSCO filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was granted by docket entry on October 21, 2021.

On October 13, 2021, the Commission issued a docket entry establishing a procedural schedule and related requirements. Petitions to Intervene were filed on October 13, 2021 by Citizens Action Coalition of Indiana, Inc. ("CAC"), on October 21, 2021 by the NIPSCO Industrial Group ("Industrial Group"),[1] on October 26, 2021 by Steel Dynamics, Inc. ("SDI"), on December 6, 2021 by Archer Energy, LLC ("Archer Energy"), and on February 25, 2022 by the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796 (the "Union") (collectively, the "Intervenors"). The Presiding Officers granted each petition to intervene by docket entry. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated.

On January 13, 2022, Petitioner filed its Notice of Substitution of Witness notifying the Commission that Jennifer Harding was being substituted for and adopting the direct testimony and attachments previously prefiled by Bryan Trapp.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held in Fort Wayne, Indiana on January 13, 2022, at which one member of the public testified.

On January 20, 2022, the OUCC and Intervenors prefiled their respective cases-in-chief and/or direct testimony. In addition to written consumer comments submitted as Public's Exhibit No. 8, the OUCC's prefiled case-in-chief included testimony and attachments from the following witnesses:

- Mark H. Grosskopf, Senior Utility Analyst
- Scott O. Viefhaus, Utility Analyst I
- Heather R. Poole, Director of Natural Gas Division
- Barbara A. Smith, Executive Director, Technical Operations
- Leja D. Courter, Chief Technical Advisor

[1] The companies that comprise the Industrial Group are BP Products North America, Inc., Cargill, Inc., Cleveland-Cliffs Inc., General Motors LLC, Linde, NLMK Indiana, United States Steel Corporation, and USG Corporation.

- David J. Garrett, Managing Member of Resolve Utility Consulting, PLLC
- Brien R. Krieger, Utility Analyst

The Industrial Group's prefiled the testimony and attachments of Brian C. Collins, Managing Principal, Brubaker & Associates, Inc.; Brian C. Andrews, Associate, Brubaker & Associates, Inc.; and Michael Gorman, Managing Principal, Brubaker & Associates, Inc. SDI prefiled testimony from Kevin C. Higgins, Principal, Energy Strategies, LLC. CAC and Archer Energy did not prefile testimony. The Union had not intervened at the time the OUCC and Intervenor testimony was due.

On February 15, 2022, NIPSCO, on behalf of itself, the Industrial Group, and the OUCC, filed an Unopposed Joint Motion for Extension of Time requesting a one-week extension of the time to file rebuttal and cross-answering testimony to provide the parties an opportunity to continue settlement discussions. The Presiding Officers granted the request by docket entry on February 16.

On February 22, 2022, NIPSCO, on behalf of itself, the Industrial Group, SDI, and the OUCC (the "Moving Parties"), filed a Joint Notice of Agreement in Principle and Request to Vacate a Portion of Evidentiary Hearing Dates. In the Joint Notice, the Moving Parties notified the Commission that an agreement in principle with respect to resolution of all disputes, claims, and issues in this Cause had been reached by and among the Moving Parties. The Joint Notice further indicated the Moving Parties were in the process of reducing the agreement to writing for formal execution. The Joint Notice indicated that the CAC and Archer Energy were taking no position on the settlement agreement.

On February 23, 2022, the Presiding Officers issued a docket entry requiring the Moving Parties to submit their settlement agreement and supporting testimony on or before March 2, 2022. The Docket Entry also scheduled an Evidentiary Hearing in this Cause for March 15, 2022.

On March 2, 2022, Petitioner filed a Stipulation and Settlement Agreement (the "Settlement") among Petitioner, the OUCC, the Industrial Group, and SDI (collectively, the "Settling Parties") resolving all disputes, claims, and issues raised in this Cause. On that date, Petitioner also filed the Settlement Testimonies of Erin E. Whitehead and Jeffrey D. Newcomb. The OUCC filed the Settlement Testimony of Mark H. Grosskopf, and the Industrial Group filed the Settlement Testimony of Brian C. Collins. The OUCC also prefiled additional written consumer comments pertaining to this proceeding as Public's Exhibit No. 10. SDI did not file settlement testimony, and the remaining parties – Archer Energy, CAC, and the Union – did not file testimony in support of or in opposition to the Settlement.

On March 4, 2022, Petitioner submitted late-filed Attachments 1-C and 1-D to the Direct Testimony of Michael Hooper consisting of the Proofs of Legal Notice Publication and Customer Notice. On March 11 and 14, 2022, the Presiding Officers issued docket entry questions to Petitioner regarding the Settlement, to which Petitioner responded on March 14 and 15, 2022, respectively.

The Commission held an Evidentiary Hearing in this Cause on March 15, 2022, at 1:30 p.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, Petitioner, the OUCC, the Industrial Group, and SDI appeared and participated, and the exhibits of the parties were admitted into the record without objection.

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

1. **<u>Notice and Jurisdiction</u>.** Notice of the Petition filed in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for gas service. Notices of the public hearings in this Cause were given and published as required by law. Petitioner is a "public utility" and a "gas utility" as defined in Ind. Code ch. 8-1-2 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by Indiana law, including the approval of rates and charges for utility service under Ind. Code § 8-1-2-42. As such, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **<u>Petitioner's Organization and Utility Property</u>.** NIPSCO is a limited liability company and public utility organized and existing under Indiana law with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders natural gas public utility service in Indiana by means of utility plant, property, equipment, and related facilities owned, operated, managed, and controlled by it (collectively, the "Utility Property"), which are used and useful for the convenience of the public in the production, storage, transmission, distribution, and furnishing of natural gas. NIPSCO provides natural gas utility service to approximately 850,000 residential, commercial, and industrial customers. NIPSCO is a wholly owned subsidiary of NiSource Inc., an energy holding company.

Petitioner maintains its Utility Property in compliance with all state and federal regulatory requirements and standards for gas utility operations. The projected original cost of Petitioner's utility plant in service as of June 30, 2022 was $3,753,525,563. After adjusting for accumulated depreciation of approximately $(1,693,189,843) and other adjustments of $111,774,157, the net original cost of Petitioner's rate base was projected to be approximately $2,172,109,877 at the same date. The original cost of Petitioner's utility plant in service as of December 31, 2022 (end of test year) in its case-in-chief, as adjusted, is projected to be approximately $4,004,668,454. After adjusting for accumulated depreciation of approximately $(1,703,757,826) and other adjustments of $117,758,507, the net original cost of Petitioner's rate base is projected to be approximately $2,418,669,135 at the same date. Furthermore, in order to properly serve the public located in its service area and to discharge its duties as a public utility, Petitioner is continuing to make numerous additions, replacements, and improvements to its utility systems.

3. **<u>Existing Rates</u>.** Petitioner's existing basic rates and charges for gas utility service were established by the Commission's September 19, 2018 Order in Cause No. 44988 ("2018 Rate Order"). NIPSCO's petition initiating Cause No. 44988 was filed with the Commission on September 27, 2017. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than fifteen (15) months have passed since the filing date of NIPSCO's most recent request for a general increase in its basic rates and charges.

Petitioner's current gas depreciation rates were authorized by the Commission's 2018 Rate Order. NIPSCO's current common and electric depreciation rates and last common and electric depreciation study were approved in the Commission's December 4, 2019 Order in Cause No. 45159. Petitioner is proposing no change to its common depreciation accrual rates in this Cause.

Pursuant to Ind. Code § 8-1-2-42(g), NIPSCO files a quarterly Gas Cost Adjustment ("GCA") proceeding in Cause No. 43629 GCA XXX, to adjust its rates to account for fluctuation in its gas costs. NIPSCO recovers through its GCA the actual cost of Unaccounted For Gas ("UAFG") up to a maximum UAFG percentage of 1.04%, which was approved in the Commission's November 4, 2010

Order in Cause No. 43894. NIPSCO also recovers bad debt expense associated with the cost of gas through its GCA. NIPSCO proposes to continue both of these recoveries through the GCA.

Pursuant to the Commission's December 7, 2011 Order in Cause No. 44094, NIPSCO files an annual update to Appendix D – Universal Service Program ("USP") Factors in a compliance filing in Cause No. 44094 to be applicable for the billing month of October.

Pursuant to the Commission's December 28, 2011 Order in Cause No. 44001, NIPSCO also files an annual proceeding in Cause No. 44001 GDSM XX for recovery of program costs associated with approved demand side management and energy efficiency programs through its Rider 172 – Gas Demand Side Management ("GDSM") Rider and Appendix C – GDSM Factors.

Pursuant to the Commission's January 28, 2015 Order in Cause No. 44403 TDSIC 1, NIPSCO files a semi-annual proceeding in Cause No. 44403 TDSIC XX to recover 80% of approved capital expenditures and TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution, and storage system improvements ("TDSIC Projects") through its Rider 188 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix F – Transmission, Distribution and Storage System Improvement Charge Adjustment Factor ("TDSIC Mechanism"). Pursuant to the Commission's July 22, 2020 Order in Cause No. 45330, NIPSCO now files the TDSIC Mechanism in Cause No. 45330 TDSIC XX.

Pursuant to the Commission's September 19, 2018 Order in Cause No. 45007, NIPSCO files a semi-annual proceeding in Cause No. 45007 FMCA XX to recover 80% of approved federally mandated costs through its Rider 190 – Federally Mandated Cost Adjustment Rider and Appendix G – FMCA Factors ("FMCA Mechanism"). Pursuant to the Commission's December 1, 2021 Order in Cause No. 45560, NIPSCO now files the FMCA Mechanism in Cause No. 45560 FMCA XX.

4. Test Year. As authorized by Ind. Code § 8-1-2-42.7(d)(1) ("Section 42.7"), Petitioner proposed a forward-looking test period using projected data. As provided in the Commission's October 13, 2021 Docket Entry, the test year to be used for determining Petitioner's projected operating revenues, expenses, and operating income shall be the 12-month period ending December 31, 2022. The historic base period is the 12-month period ending December 31, 2020.

5. NIPSCO's Requested Relief and Direct Evidence. In its case-in-chief (after corrections), NIPSCO requested Commission approval of an overall increase in rates and charges for gas service that would produce additional gas revenues in two steps of approximately $109.7 million, which would reflect an overall revenue increase of 13.47%, inclusive of gas costs. Pet. Ex. 3, Attach. 3-A-S2; Pet. Ex. 2, Page 17. In its Petition, NIPSCO also requested Commission approval of a new schedule of rates and charges, general rules and regulations, and riders applicable to gas utility service, revised depreciation rates applicable to gas plant in service; approval of a mechanism to modify rates prospectively for changes in federal or state income tax rates, URT rates, and PUF rates; and other necessary and appropriate accounting relief.

A. Michael W. Hooper. Mr. Hooper, President and Chief Operating Officer, provided an overview of NIPSCO including its corporate structure, strategic vision, stakeholder commitments, and customer service goals. He also described NIPSCO's gas system, current credit rating, and commitment to safety, and he explained how NIPSCO's vision and commitments have been implemented since the 2018 Rate Order.

Mr. Hooper stated that NIPSCO is filing this case now because the investment in its gas system and operating expenses have grown, and the result is that NIPSCO's current rates are insufficient to recover the increased costs of providing service to its customers. He explained that federal pipeline safety requirements have increased since the 2018 Rate Order and NIPSCO's focus on damage prevention requires additional investments to continue to mitigate the risk of third-party damages to NIPSCO's underground facilities.

Mr. Hooper then identified NIPSCO's witnesses and the subject matter of their testimony. Finally, he described how NIPSCO provided notice of its intent to file a gas rate case in accordance with the Commission's General Administrative Order ("GAO") 2013-5, published notice of the filing in each county where NIPSCO provides gas service, and provided its residential customers with written notice of the relief requested in this proceeding.

B. Erin Whitehead. In her direct testimony, Ms. Whitehead, Vice President of Regulatory Policy and Major Accounts for NIPSCO, discussed NIPSCO's compliance with statutory and regulatory requirements; described the proposed Test Year; provided a background of NIPSCO's existing gas rates; explained the key drivers and objectives for filing this case; and summarized NIPSCO's principles and objectives for designing rates in this proceeding. She also described NIPSCO's proposed Gas Service Tariff, Original Volume No. 9, including the Schedule of Rates, Riders, and General Rules and Regulations (the "Proposed Tariff"), proposed standard Agreement for Gas Service (for Rates 225, 228, and 238), and proposed Rate Release Form, and explained how the Proposed Tariff differs from NIPSCO's Gas Service Tariff, Original Volume No. 8 (the "Current Tariff").

Ms. Whitehead testified that NIPSCO proposes to implement the requested rates in a two-step process to reflect the utility property that is used and useful at the time the rates are put into effect. She stated assuming an order date of July 26, 2022, which NIPSCO's "Step 1" rates will be calculated to reflect the actual rate base, related annualized depreciation and amortization expense, and actual capital structure as of June 30, 2022, to become effective on September 1, 2022. Once approved, these rates would remain in effect until replaced by Commission approved rates as part of NIPSCO's proposed "Step 2" compliance filing. In Step 2 NIPSCO would recalculate rates to reflect actual rate base, related annualized depreciation and amortization expense, and actual capital structure as of December 31, 2022, to become effective on March 1, 2023. She stated that consistent with the Commission's prior orders in future test year rate cases, NIPSCO proposes that the Step 1 and Step 2 rates would take effect immediately upon filing on an interim-subject-to-refund basis, with other parties being offered a period of 60 days to review and present any objections.

C. Jeffrey D. Newcomb. Mr. Newcomb, Manager, Regulatory – Rate Case Optimization, presented the results of NIPSCO's gas operations for the Historic Base Period and the projected results for the Forward Test Year, adjusted on a proforma basis for the normalization and annualization of certain amounts included in these periods. He testified that retail gas revenues at current rates do not and will not produce a level of net operating income sufficient to provide a fair return on the net original cost of NIPSCO's property, plant, and equipment owned, operated, and serving jurisdictional gas customers. He also quantified the amount by which retail gas revenues should be increased so that NIPSCO may have the opportunity to earn a fair and reasonable return.

Additionally, Mr. Newcomb discussed the application of GAO 2013-5 and Minimum Standard Filing Requirements ("MSFRs") as well as NIPSCO's proposed rate relief in this proceeding. He also supported normalization adjustments made to the Historic Base Period and ratemaking adjustments made to the Forward Test Year to support NIPSCO's proposed basic rates and charges. Mr. Newcomb testified that NIPSCO is requesting that retail gas rates be designed to recover through base rates the gross retail gas revenue amount of $924,187,101, which is an increase of $109,691,969 over the forecasted test year proforma results based on current rates. He stated that all else being equal, rates based upon this level of annual retail gas revenue requirement will provide NIPSCO with an opportunity to earn annual jurisdictional net operating income of $166,162,570. NIPSCO's proposed rates have been calculated using NIPSCO's requested return on the Forward Test Year original cost rate base and capital structure.

D. <u>Elizabeth A. Dousias</u>. Ms. Dousias, Manager of Regulatory for NCSC, presented schedules that demonstrate NIPSCO's projected rate base as of June 30, 2022 (Step 1) and December 31, 2022 (Step 2), which reflects the Forward Test Year investment level that is utilized within the revenue requirement sponsored by NIPSCO witness Newcomb. She testified that NIPSCO's projected net original cost rate base for ratemaking purposes is $2,416,457,599 as of December 31, 2022.

Ms. Dousias explained the Cause No. 44988 regulatory asset adjustment shown on Attachment 3-C-X (S1, S2), RB-5. She testified that in the 2018 Rate Order, the Commission approved the inclusion of TDSIC deferred balances as of December 31, 2018, which were to be amortized over a seven-year period. She stated that NIPSCO is not proposing a change in the amortization period of these assets in this proceeding. The 2021 and 2022 projected amounts were calculated by adjusting the December 31, 2020 actual balance. She stated that Adjustment RB 5-21 in the amount of $2,252,941 and Adjustment RB 5-22 in the amount of $2,252,940 decrease the regulatory asset balance, and the $6,195,174 Cause No. 44988 Regulatory Asset reflects the projected unamortized balance of the TDSIC regulatory asset as of December 31, 2022.

Ms. Dousias explained the TDSIC regulatory asset adjustment shown on Attachment 3-C-X (Sl, S2), RB-6. She testified that this adjustment rolls forward normalized Historic Base Period deferrals to those projected as of December 31, 2022. She stated that in accordance with the Commission's Orders in Cause Nos. 44403 and 45330, NIPSCO is authorized to defer, as a regulatory asset, 20% of the TDSIC costs incurred in connection with its designated eligible improvements and recover those deferred costs in its next general rate case per Ind. Code § 8-1-39-9(c). She stated that Adjustment RB 6-21 in the amount of $3,235,962 and Adjustment RB 6-22 in the amount of $6,271,280 increase the regulatory asset balance to reflect ongoing TDSIC 4 deferrals.

Ms. Dousias explained the FMCA regulatory asset adjustment shown on Attachment 3-C-X (S1, S2), RB-7. She testified this adjustment rolls forward normalized Historic Base Period deferrals to those projected as of December 31, 2022. She stated that in accordance with the Commission's Orders in Cause Nos. 45007 and 45183, NIPSCO is authorized to defer, as a regulatory asset, 20% of the FMCA costs incurred in connection with its Pipeline Safety Compliance Project and PHMSA Compliance Project, and recover those deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2). Adjustment RB 7-21 in the amount of $4,280,587 and Adjustment RB 7-22 in the amount of $3,917,977 increase the regulatory asset balance to reflect ongoing FMCA deferrals.

Ms. Dousias explained the Material and Supplies adjustment shown on Attachment 3-C-X (S1, S2), RB-8. She testified this adjustment rolls forward normalized Historic Base Period deferrals to those projected as of December 31, 2022. She stated that Adjustment RB 8-21 in the amount of

$1,699,429 decreases the materials and supplies balance to reflect the future projected balance based on historical trended amounts.

Ms. Dousias explained the Gas Storage Current balance as shown on Attachment 6 3-C-X (Sl, S2), RB-9. She testified that the Gas Storage Current balances on Line 9 reflects the 13-month average and forecasted 13-month average balance of NIPSCO's Current Underground Storage. She stated that Adjustment RB 9-21 in the amount of $21,857,355 and RB 9-22 in the amount of $3,377,187 increase the Gas Storage Current Balance to reflect the future projected balance.

Finally, Ms. Dousias explained the Gas Underground Storage Non-Current balances shown on Attachment 3-C-X (SL S2), RB-10. She testified that the Gas Underground Storage Non-Current balance on Line 10, reflects the actual and projected balance of NIPSCO's Underground Storage Non-Current and that NIPSCO has not proposed any adjustments to these balances.

E. **<u>Angela Camp</u>.** Ms. Camp, Director of Regulatory and Utility Planning for NCSC, provided an overview of the financial planning and budgeting processes used and the NIPSCO Gas 2021-2022 Financial Plan, which is the underlying basis for the rate request in this proceeding. She also sponsored the budget amounts for 2021 and 2022 sourced from the NIPSCO Gas 2021-2022 Financial Plan.

Ms. Camp described the major components of NIPSCO's revenues and the major assumptions used in the development of the forecasted 2022 revenues; the major components of NIPSCO's cost of gas sold and the major assumptions used in the development of the forecasted 2022 costs of gas sold; the major categories and components of NIPSCO's O&M expenses and the major assumptions used in the development of the forecasted 2022 O&M expenses; the major components of NIPSCO's tax expenses other than income tax and the major assumptions used in the development of the forecasted 2022 tax expenses other than income taxes; the major components and assumptions used in the development of the forecasted 2022 capital expenditures; and the major components of NIPSCO's rate base balances and the major assumptions used in the development of the forecasted 2022 other rate base balances.

F. **<u>Nick Bly</u>.** Mr. Bly, Manager of Corporate Consolidation in Financial Planning and Analysis for NCSC, provided background on the NCSC budgeting process and how that relates to the financial plan for NIPSCO. She supported the O&M expenses associated with services provided by NCSC to NIPSCO, and any adjustments to those expenses for the period beginning January 1, 2021 and ending December 31, 2021 (the "Budget Period"), and the "Forward Test Year."

Mr. Bly testified that the level of NCSC O&M expenses in the 2021 Budget Period for NIPSCO is $61,316,775 and that the variance in NCSC O&M expenses between the Normalized Historic Base Year and the 2021 Budget Period is an increase of $1,239,464 or 2.1%. He explained that using the CPI-All Urban Consumers Inflation average for the 12-months ended May 31, 2021 of 1.8%, the increase is substantially explained by the CPI index for related merits and inflation on outside services. He stated that the level of NCSC O&M expenses in the Forward Test Year for NIPSCO is $61,188,863 and the variance for NCSC O&M expenses is a decrease of $127,912 or 0.2%, which is immaterial and well below inflation.

Mr. Bly testified that the ratemaking adjustment to the Forward Test Year is a decrease of $702,723 or 1.1% and that adjustments were made to reduce the Forward Test Year for nonrecoverable items such as charitable donations, lobbying, advertising, and membership fees, as well as for profit sharing. Details of the non-recoverable items were presented on Attachment 6-A, Page 3. Mr. Bly added that the NCSC expenses expected to be allocated to NIPSCO in the Forward Test Year (after ratemaking adjustments) are $60,486,140.

G. **<u>Gunnar J. Gode</u>.** Mr. Gode, Vice President and Chief Accounting Officer for NCSC, provided background on the relationship between NCSC and NIPSCO. He also supported the actual O&M expenses associated with services provided by NCSC to NIPSCO for the Historic Base Period, as well as certain normalization adjustments to those expenses (which when taken together, comprise the "Normalized Historic Base Period"). He testified that the same underlying allocation methodologies applied during the Historic Base Period are used for the expected NCSC services provided to NIPSCO for the Budget Period and the Forward Test Year.

Mr. Gode testified that the actual amount of NCSC O&M expenses in the Historic Base Period for NIPSCO are $55,204,741. He explained that to arrive at a comparable, ongoing level of allocated expenses, certain adjustments were made to the Historic Base Period, resulting in a Normalized Historic Base Period total expense of $60,077,311. He stated that adjustments were made to the Historic Base Period for including: a decrease to the School Safety Program Reclass of $62,500; an increase to the Long-Term Incentive Plan ("LTIP") of $344,240; a decrease to the Retention Award Adjustment of $118,778; an increase to the Corporate Incentive Payout Normalization Adjustment of $1,409,619; and an increase to the Allocation Update of $3,299,990 to reflect the current percentage of NCSC service costs being allocated to NIPSCO.

H. **<u>Patrick L. Baryenbruch</u>.** Mr. Baryenbruch, President of Baryenbruch & Company, LLC, presented the results of a study that evaluated the services provided during the 12 months ended December 31, 2020, by NCSC to NIPSCO (the "Study"). The Study was undertaken in conjunction with NIPSCO's rate case and was attached to his testimony as Attachment 8-B. He testified that the purpose of the Study was to determine the reasonableness and necessity of NIPSCO affiliate charges from NCSC for services provided during 2020.

Based on his review, Mr. Baryenbruch concluded that the cost per NIPSCO customer for administrative and general services from NCSC was reasonable compared to the cost per customer for similar utility service companies. He explained that during 2020, NIPSCO was charged an average of $53 per customer for these services by NCSC, which is well below the average of $116 per customer for comparison group service companies. He stated that NIPSCO's $53 annual cost is lower than 20 and higher than one of the 21 comparison group service companies. He further stated that NCSC's services were provided to NIPSCO during 2020 at the lower of cost or market and that on average, the hourly rates for outside service providers are 55% higher than comparable hourly rates charged by NCSC. He testified that if all of the managerial and professional services now provided by NCSC had been outsourced in 2020, NIPSCO and its customers would have incurred $16.9 million in additional expenses. He added that NCSC's charges do not include any profit markup and only the actual cost of the service provided was charged

Mr. Baryenbruch concluded that NIPSCO's customer accounts services costs, which include charges from NCSC, were well below the average of the utility comparison group from Indiana and neighboring states. He stated that during 2020, NIPSCO's accounts services cost per customer was $21.47 compared to the utility comparison group's 2020 average of $30.26. He also noted that the services that the NCSC provides are necessary and would be required even if NIPSCO were a stand-alone gas utility.

I. **Steven Sylvester.** Mr. Sylvester, Vice President and General Manager for NIPSCO, provided an overview of NIPSCO's gas O&M, storage, liquefied natural gas ("LNG"), and damage prevention organizations, described NIPSCO's pipeline safety programs, processes, and the implementation of its Safety Management System, and described the components of NIPSCO's pipeline safety programs, which are anticipated to be included in a future proceeding to seek recovery of federally mandated costs. He sponsored an adjustment to NIPSCO's Forward Test Year to reflect the addition of employees in NIPSCO's Gas Measurement and Transmission Department necessary to address increased work volume and to maintain safe and reliable operation of NIPSCO's system.

J. **Rick Smith.** Mr. Smith, Manager of Operations for NIPSCO, provided an overview of NIPSCO's Damage Prevention Organization, described NIPSCO's ongoing focus on damage prevention, and supported adjustments to reflect changes in costs associated with programs designed to continue to mitigate the risk of third-party damages to NIPSCO's underground facilities ("Damage Prevention Program"). He testified that since 2017, NIPSCO has improved its Damage Prevention Program through the implementation of a safety management system and ongoing collaboration with the Commission's Pipeline Safety Division ("PSD") in reviewing damage information and discussing ways to continue to improve damage prevention efforts.

Mr. Smith testified that NIPSCO's continuous improvement initiatives have resulted in a reduction in facility damages. He stated that NIPSCO has reduced damages per 1,000 locate tickets (Damages per Thousand) from 3.75 in calendar year 2013 to 1.90 as of July 31, 2021. He added that NIPSCO has reduced the number of damages for "Locating Practices Not Sufficient from 292 in calendar year 2013 to 139 as of July 31, 2021, which occurred at a time when there was an increase of locate ticket requests. He explained that while NIPSCO's damage prevention efforts have resulted in fewer damages since 2013, NIPSCO must comply with CFR 49 Part 192.907(a) by making continual improvements. He stated that the level of risk associated with excavation activities, as well as the ongoing collaboration with the PSD, also drives NIPSCO's continued efforts to improve in this area. Based on an evaluation of its practices, he stated that NIPSCO identified additional measures that could be implemented to achieve further safety improvements, including an increase in excavator outreach and education coupled with additional audits to further reduce damages to its infrastructure.

K. **Andrew Campbell.** Mr. Campbell, Director of Regulatory Support & Planning for NIPSCO, described NIPSCO's gas infrastructure and explained how the quality of that system supports the safe delivery of natural gas. He also described recent changes to NIPSCO's Rates 128 and 138 in its Current Tariff and discussed the planning assumptions that support NIPSCO's forecasted cost of gas sold, forecasted gas in storage, forecasted on-system storage activity, and the pro forma adjustments for LNG liquefaction costs. Finally, he provided support for the adjustment to the NIPSCO's test year revenues to remove forecasted off-system displacement revenues.

L. **Kimberly Cartella.** Ms. Cartella, Director of Compensation for NCSC, supported NiSource total rewards, which includes supporting details for total rewards programs, policies, and philosophies including base compensation/wages, incentive compensation, and employee benefits such as healthcare and dental coverage. She also provided comparative analyses to establish the reasonableness and competitiveness of wages, salaries, and incentive compensation.

M. **John Spanos.** Mr. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, was retained by NIPSCO to recommend depreciation rates for its gas plant as of December 31, 2020, and to recommend depreciation rates for its forecasted gas plant in service as of December 31, 2022. He sponsored Attachment 13-B, which states the results of his depreciation analysis related to NIPSCO's gas plant as of December 31, 2020 (the "Depreciation Study"). He also sponsored Attachment 13-C, which states the results of his depreciation analysis related to NIPSCO's projected gas plant in service as of December 31, 2022.

Mr. Spanos described the contents of the Depreciation Study and he stated that he used the straight-line remaining life method of depreciation the equal life group procedure. He explained those concepts and stated that this method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational manner. He also explained how he calculated the forecasted depreciation rates as of December 31, 2022. He stated that first, the plant in service and book reserve were brought forward from December 31, 2020 to December 31, 2022 based on the capital budget by account and year. The book reserve by account as of December 31, 2022 was developed by adding the annual accruals and gross salvage each month and subtracting retirements and cost of removal each month for the two-year period. Once the plant in service as of December 31, 2022 was developed by vintage within account and the book reserve is developed by account, then the December 31, 2022 depreciation rates were calculated using the same methods and procedures as in the 2020 Depreciation Study.

N. **Jennifer Harding.** Ms. Harding, Director of Income Tax Operations for NCSC, presented NIPSCO's federal and state income tax expense and taxes other than income tax expense adjustments for the Forward Test Year at present and proposed rates as shown on Attachment 3-A-S2 (Column E) to her testimony. She also presented NIPSCO's Accumulated Deferred Income Taxes ("ADIT") and Post 1970 Investment Tax Credit ("ITC") balances and related pro forma adjustments, which are included as components of NIPSCO's Capital Structure as shown in Attachment 3-A-S2. She further presented NIPSCO's proposal for capturing future tax rate changes.

Ms. Harding described the basic components of federal income tax expense reflected in NIPSCO witness Newcomb's accounting attachments, explained the implication arising from the use of accelerated depreciation for federal income tax purposes, and noted the differences between what is depreciated for income tax purposes and for book purposes. She then described other adjustments that needed to be made to account for changes in the federal income tax rate including NIPSCO's treatment of Excess Accumulated Deferred Income Tax ("EADIT") from the Tax Cut and Jobs Act and Allowance for Funds Used During Construction ("AFUDC"). She testified that NiSource has additional interest expense obligations relating to the ongoing utility operations of NiSource's public utility subsidiaries, a portion of which she allocated to NIPSCO based on NiSource's equity investment in NIPSCO compared to its equity investment in all subsidiaries. As shown on Attachments 14-A and 14-B, the amount of the adjustment is a decrease to Forward Test Year income tax expense of $30,412.

Next, Ms. Harding explained NIPSCO's state income tax expense. She explained the tax calculations include Indiana Adjusted Gross Income taxes calculated at 4.9%, as adjusted for the non-deductibility of the URT; the excess deferred taxes resulting from the decrease in the state tax rate from 5.875% to 4.9%; and the non-deductibility of certain expenses as shown on Attachments 14-A and 14-B. She then explained NIPSCO's proposals to reflect $16,820,000 in real and personal property taxes, $6,495,741 in URT, and $31,997,376 in federal and state income taxes. Finally, Ms.

Harding explained the components of NIPSCO's capital structure and described NIPSCO's proposal for capturing future tax rate changes.

O. **Vincent V. Rea.** Mr. Rea, Managing Director of Regulatory Finance Associates, LLC, presented supporting evidence, analysis, and a recommendation regarding the appropriate rate of return on common equity and overall rate of return that the Commission should establish for NIPSCO's jurisdictional gas operations in relation to its revenue requirement calculation. He sponsored Attachment 15-A, which contained the following nine schedules: Schedule 1 – Professional Qualifications of Vincent V. Rea; Schedule 2 – Comparative Risk Assessment; Schedule 3 – Analysis of Regulatory Mechanisms; Schedule 4 – DCF Method - Gas LDC Group; Schedule 5 – DCF Method - Combination Utility Group; Schedule 6 – DCF Method - Non-Regulated Group; Schedule 7 – Capital Asset Pricing Model; Schedule 8 – Risk Premium Method; and Schedule 9 – Book Value vs. Market Value Capitalization Ratios.

To estimate NIPSCO's cost of equity, Mr. Rea used three models to analyze market data and financial information for 27 companies which included seven companies comprising the Gas LDC Group, nine companies comprising the Combination Utility Group, and 11 companies comprising the Non-Regulated Group. ;He testified that using this approach yielded individual estimates of the cost of equity for NIPSCO thereby ensuring a thorough and comprehensive analysis. He recommended that the cost of common equity for NIPSCO's gas utility operations is in the range of 10.25% to 10.75% and that 10.50% is the appropriate cost of equity to apply in this proceeding. Based upon this finding, he also determined that NIPSCO's weighted average cost of capital ("WACC") is 6.87%, which is based on NIPSCO's forward test year-end regulatory capital structure as of December 31, 2022. In developing his recommendations, he placed primary emphasis on the cost of equity estimates derived for the Gas LDC Group, and the Combination Utility Group to a lesser extent, while still recognizing that the estimates derived for the Non-Regulated Group provide useful perspective into the returns required by investors for non-utility company investments with risk profiles similar to NIPSCO.

P. **Melissa Bartos.** Ms. Bartos, Vice President at Concentric Energy Advisors, explained how residential and commercial billing month sales for the Historic Base Period are normalized for weather. She also explained the adjustment to unbilled Historic Base Period consumption to reflect the unbilled estimate that would have been made under normal weather conditions. Furthermore, she explained how design day consumption is derived and explained the methodology used to develop the forecasted number of customers and usage for the 2021 Budget Period and the Forward Test Year.

Q. **Ronald J. Amen.** Mr. Amen, Managing Partner with Atrium Economics, LLC, testified that Atrium was retained by NIPSCO as a consultant in the area of utility costing and rate design to help conduct a cost of service study to determine the embedded costs of serving NIPSCO's natural gas retail customers and to provide support with the development of its rates. Mr. Amen discussed the purpose of an Allocated Cost of Service Study ("ACOSS") and described the Atrium Cost of Service Model ("Atrium Model") used for NIPSCO's gas cost of service studies. He also discussed various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in NIPSCO's gas cost of service studies. He described the "Special Studies" employed to apportion the various categories of plant and O&M expenses to the respective customer classes. He presented the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS. He explained that this presentation includes a discussion of the resulting unit costs by class for customer, demand, and commodity related costs with the ACOSS. Mr. Amen then discussed revenue allocation and rate design principles, and the appropriate guidelines for use in evaluating class revenue levels and rate structures. He explained and supported the allocation of NIPSCO's revenue deficiency to the various rate schedules consistent with the class revenue mitigation objectives discussed by Ms. Whitehead. Finally, he discussed NIPSCO's rate design proposals.

R. Judith L. Siegler. Ms. Siegler, Lead Regulatory Studies Analyst for NCSC, provided support for NIPSCO's revenue adjustments REV lA-20, REV lB-20, REV lC-20, REV 1-22R, REV 2-22R, and REV 8-22R and cost of gas sold ("COGS") adjustments COGS lA-20, COGS lB-20, COGS 1-22R, COGS 2-22R, and COGS 5-22R.

Ms. Siegler stated that adjustment REV lA-20 increases Historic Base Period gas operating revenues in the amount of $21,973,383 to normalize weather-related sales and that adjustment COGS 1-20 increases Historic Base Period gas cost in the amount of $13,684,851 to normalize weather. She stated that adjustment REV 1-22R increases Forward Test Year gas operating revenues in the amount of $50,902,238 to update the forecast to reflect a 20-year average weather normalization and adjustment COGS 1-22R increases Forward Test Year gas costs in the amount of $54,141,333 to reflect a 20-year average weather normalization. She stated that adjustment REV 1B-20 decreases Historic Base Period gas operating revenues in the amount of $270,857 to remove all revenue from Guaranteed Minimum contracts and that these incremental revenues were billed to customers who did not meet their minimum margin obligation contracts. She explained that the existing contracts are expiring, the number of new contracts are minimal, and NIPSCO did not include these revenues in the NIPSCO gas utility budgets for the 2021 Budget Period and Forward Test Year. She testified that adjustment REV 1C-20 decreases Historic Base Year gas operating revenues in the amount of $659,909 to adjust billing determinants and margins to reflect migration of customers and that adjustment COGS 1B-20 decreases Historic Base Year gas costs in the amount of $646,815 to adjust billing determinants and margins to reflect migration of customers.

Ms. Siegler testified that adjustment REV 2-22R decreases Forward Test Year gas operating revenues in the amount of $14,765,448 to remove Alternative Regulatory Plan program revenues and that adjustment COGS 2-22R decreases Forward Test year gas costs in the amount $9,565,448 to remove Alternative Regulatory Plan program gas costs. She stated that adjustment REV 8-22R increases Forward Test Year gas operating revenues in the amount of $144,405 to include gas revenues associated with commercial and industrial balancing. She explained that the commercial and industrial balancing revenue included in the 2022 forecast is at margin, so a ratemaking adjustment is needed to gross up the budgeted amount to properly calculate revenue. Finally, she stated that adjustment COGS 5-22R increases Forward Test Year gas costs in the amount of $1,768,978 to include gas costs associated with commercial and industrial balancing.

6. Intervenor Testimony. The OUCC and Intervenors raised a number of challenges to NIPSCO's filing, including challenging depreciation rates, rate of return, operating and maintenance ("O&M") expenses, cost of service allocations, and rate design. The OUCC, Industrial Group, and SDI also raised various issues regarding NIPSCO's proposed tariff changes. SDI challenged certain aspects of Petitioner's cost of service study and revenue allocations.

Upon reviewing the OUCC and Intervenors' cases-in-chief, NIPSCO and the other parties began discussing potential settlement. On February 22, 2022, NIPSCO, on behalf of itself, the

Industrial Group, SDI and the OUCC, filed a Joint Notice of Agreement in Principle and Request to Vacate a Portion of the Evidentiary Hearing, notifying the Commission that an agreement in principle with respect to resolution of all issues had been reached by and among those parties. The Joint Notice further indicated that CAC and Archer Energy were not taking a position on the settlement.

On March 2, 2022, Petitioner filed a Settlement Agreement among the Settling Parties resolving all disputes, claims, and issues raised in this Cause. In support of the Settlement, the Settling Parties also filed the settlement testimony of their respective witnesses. SDI did not file settlement testimony, and the remaining parties – Archer Energy, CAC, and the Union – did not file testimony in opposition to the Settlement.

7. Settlement Agreement. The Settlement filed with the Commission on March 2, 2022, presents the Settling Parties' resolution of all issues in this Cause. The Settlement is attached to this Order and incorporated by reference. Schedules supporting the calculation of Petitioner's revenue requirement as of December 31, 2022, pursuant to the Settlement, are included in Joint Exhibit A to the Settlement. The witnesses offering settlement testimony discussed the arm's-length nature of the negotiations and the efforts undertaken to reach a balanced settlement that fairly resolves the issues. The Settlement and supporting evidence are outlined below.

A. Stipulated Revenue Requirement. As discussed by NIPSCO witness Newcomb, Paragraph B.1. of the Settlement sets forth the parties' agreement with respect to the total revenue requirement and resulting net operating income. The stipulated total revenue requirement is $886,319,992, which constitutes an increase in revenues at present rates of $71,800,282. The stipulated revenue increase reflects a reduction of approximately $37.9 million from NIPSCO's case-in-chief proposal of $924,187,101. The OUCC and Industrial Group had recommended an overall revenue increase of $56.4 million and $49.3 million, respectively. Pub. Ex. 1, Attach. MHG-1, Sch. 4; Industrial Group Ex. 1, at p. 3.

B. Rate Base. Mr. Newcomb testified regarding the Settling Parties' agreement with respect to Petitioner's test year end net original cost rate base as set forth in Paragraph B.2. of the Settlement. The stipulated net original cost rate base on which the Settling Parties agreed Petitioner should be permitted to earn a return is $2,418,669,134. The Settling Parties also agreed to a Rate Base Update Mechanism as set forth in Paragraph B.7. of the Settlement and as discussed in Paragraph 7.H. of this Order.

C. Cost of Capital. Petitioner's proposed cost of equity in its case-in-chief was 10.50%. The OUCC proposed 9.30%, and the industrial Group proposed 9.25%. As part of the overall settlement package, the Settling Parties agreed to 9.85% cost of equity. Mr. Grosskopf testified the OUCC considers this a fair and reasonable result when combined with other considerations and compromises made in the Settlement. The resulting WACC based on Petitioner's projected capital structure is 6.55%, based upon: (a) a Net Original Cost Rate Base of $2,418,669,134; and (b) NIPSCO's forecasted capital structure. Joint Ex. 1, Para. B.2(a). According to the Settlement, Petitioner should be authorized a fair return of $158,422,828 for an overall return for earnings test purposes of 6.55%.

D. Depreciation and Amortization. NIPSCO sought to establish new depreciation accrual rates calculated using the Equal Life Group ("ELG") methodology. As a part of the compromise included in the overall settlement package, NIPSCO agreed to use the Average Life

Group ("ALG") methodology and service lives of 68 years for its gas distribution services (Account 380), as recommended by Industrial Group witness Andrews. Pet. Ex. 3-S, at p. 7; Joint Ex. 1, Para. B.3(a). This results in a pro forma adjustment of $20.9 million for depreciation expense. The resulting depreciation accrual rates are shown in Joint Exhibit B to the Settlement.

Paragraph B.3(b) also sets forth the Settling Parties' agreement with respect to amortization expense. The Settling Parties agreed to a projected Cause No. 45621 Gas Rate Case Expense regulatory asset balance of $1,352,043 reflecting (i) a $63,055 reduction to the Billing System New Rate Implementation component (from $200,000 to $136,945); and (ii) a $200,000 reduction to reflect reduced costs due to settlement. Joint Ex. 1, Para. B.3(b); Pet. Ex. No. 3-S, at p. 8. The Settling Parties also agreed to Petitioner's original proposal for a 33-month amortization period for the remaining Cause No. 44988 regulatory asset (including rate case expense and then-deferred TDSIC balance) (the "44988 Regulatory Asset"). Joint Ex. 1, Para. B.3(b). The Settling Parties further agreed to a four-year amortization period for TDSIC, FMCA, COVID, and Cause No. 45621 Gas Rate Case Expense regulatory assets, resulting in a reduction of $1,153,883 in Amortization Expense.

Further, the Settlement provides that if not already addressed by an intervening base rate order, after the completion of the 33-month period, NIPSCO agrees to make a compliance filing that will reflect the reduction in amortization expense for the 44988 Regulatory Asset. Joint Ex. 1, Para. B.3(b). After the completion of the four-year period, NIPSCO agreed to make a compliance filing that will reflect the reduction in amortization expense for TDSIC, FMCA, and COVID regulatory assets, as well as Cause No. 45621 Rate Case Expense. The Settlement provides that if NIPSCO files a general rate case before the expiration of the amortization period of four years, any unamortized TDSIC, FMCA, COVID, or Cause No. 45621 Gas Rate Case Expense regulatory asset balances will be rolled into NIPSCO's next rate case.

E. <u>Taxes</u>. Paragraph B.4. of the Settlement sets forth the Settling Parties' agreement with respect to Taxes. The Settling Parties agreed to a four-year amortization period for Indiana EADIT (protected and unprotected), resulting in an increase of $1,744,143 in the annual state tax passback from $305,737 to $2,049,880. Pet. Ex. 3-S, at p. 10; Joint Ex. 1, Para. B.4(a). Upon completion of the passback of Indiana (protected and unprotected) EADIT and unprotected federal EADIT approved in Cause No. 44988 ($6,120,309), NIPSCO will make compliance filings in this Cause to increase rates to reflect the cessation of amortization upon the passback of all Indiana EADIT and unprotected federal EADIT, as the case may be. The Settling Parties also agreed on a proposal whereby NIPSCO may seek to adjust rates outside of a general rate case for modifications to State or Federal income tax rates. Joint Ex. 1, Para. B.4(b).

F. <u>Operating Revenues</u>. Paragraph B.5. of the Settlement sets forth the Settling Parties' agreement with respect to *pro forma* operating revenues. For purposes of Settlement, the Settling Parties stipulate that Gas Rent Revenue should be increased by $24,578 from $133,857 to $158,435 as proposed by the OUCC. Joint Ex. 1, Para. B.5; Pet. Ex. No. 3-S, at p. 6.

G. <u>Operations and Maintenance Expense</u>. For purposes of Settlement, the Settling Parties agreed that NIPSCO's *pro forma* O&M Expense should be decreased by $2,958,602. Joint Ex. 1, Para. B.6; Pet. Ex. 2-S, at p. 13. The decrease reflects a reduction of $1,275,000 in Gas Operations expense, a reduction of $60,116 for uncollectible expense, and a reduction of $1,623,486 for the entire adjustment related to the elimination of Petitioner's proposed fee free transaction. Joint Ex. 1, Para. B.6; Pet. Ex. 2-S, at pp. 13-14.

H. Rate Base Update Mechanism. NIPSCO witness Whitehead testified regarding the stipulated changes to the process for implementation of its authorized increase to base rates and charges for natural gas utility services in two steps as set forth in Paragraph B.7. of the Settlement. Pet. Ex. 2-S, at pp. 18-19. The first change in rates ("Phase 1") will be implemented pursuant to the process set forth in NIPSCO's case-in-chief and will be based upon the agreed revenue requirement, as adjusted to reflect the actual original cost of NIPSCO's total rate base, actual capital structure, and associated annualized depreciation and amortization expense as of June 30, 2022. *Id*. The Settlement provides that following a Final Order in this Cause approving the Settlement, Petitioner's Phase 1 rates will go into effect upon submission on an interim-subject-to-refund basis pending a 60-day review process by the other parties. Joint Ex. 1, Para. B.7.

With respect to Step 2 rates, the Settling Parties agreed NIPSCO will certify its actual total rate base, actual capital structure, and associated annualized depreciation and amortization expenses at test-year end (December 31, 2022). The Settlement provides that Step 2 rates will be based on the agreed revenue requirement as of December 31, 2022, as adjusted for NIPSCO's certification and reflecting the lesser of (a) NIPSCO's forecasted test-year-end Total Utility Plant as updated in its direct evidence ($4,004,668,454 – Pet. Ex. No. 3, Attach. 3-B-S2 RB Module), or (b) NIPSCO's certified test-year-end Total Utility Plant as of December 31, 2022. Phase 2 rates will go into effect upon submission on an interim-subject-to-refund basis pending the 60-day review process. The Settlement further provides that to the extent the actual revenue requirement resulting from either Step 1 or Step 2 rates is different from $886,319,992 (the stipulated revenue requirement), the difference shall be reflected by changing the rates set forth in NIPSCO witness Whitehead's Attachment 2-S-A in an across-the-board fashion.

I. Revenue Allocation. Paragraph B.8. of the Settlement sets forth the Settling Parties' agreement with respect to revenue allocation. The Settling Parties stipulate to the allocation of the agreed $71.8 million revenue increase between classes as follows:[2]

	Current Distribution Margin	Revenue Increase	Percentage Increase on Margin
Rate 111	$295,326,125	$52,960,388	17.9%
Rate 115	$2,404,167	$399,321	16.6%
Rate 121	$99,061,233	$9,729,065	9.8%
Rate 125	$12,859,523	$1,242,227	9.7%
Rate 128 DP	$9,191,556	$3,676,622	15.7%
Rate 128 HP	$35,286,309	$3,294,500	
Rate 134	$194,747	$0	0.0%
Rate 138	$5,154,021	$497,877	9.7%
Total		**$71,800,000**	

Joint Ex. 1, Para. B.8.; Pet. Ex. No. 2-S, at pp. 19-21.

[2] Rounds the actual agreed revenue increase of $71,800,282.

Further, the Settling Parties agreed to the allocators to be used in NIPSCO's TDSIC filings, as shown on Joint Exhibit C to the Settlement. For purposes of Settlement, the Settling Parties further agreed that the Rate 128 – Distribution Pressure subclass will be capped at a 40% increase, resulting in an allocation for Rate 128 – Distribution Pressure of $3,676,622 and Rate 128 – High Pressure of $3,294,500. The Settling Parties stipulated that no cost-of-service methodology was being adopted or endorsed by virtue of the Settlement. With respect to the DP subclass in Rate 128, the Settling Parties agreed that the second-tier threshold for the transportation charge will be changed from 300,000 to 100,000 therms (with no change to the HP tiers), with the second-tier rate remaining the same as the second-tier rate for HP, per NIPSCO's filed position.

J. **Rate Design.** In addition to the customer charge increases discussed in Paragraph 7.K. below, the Settling Parties agreed to the following customer charge increases:

	Current	NIPSCO Case-in-Chief	OUCC Case-in-Chief	Settlement
Residential	$14.00	$24.50	$15.75	$16.50
Multi Family	$17.50	$28.50	$19.75	$20.75
General Service Small	$53.00	$80.00	$59.75	$67.00
General Service Large	$400.00	$640.00	$450.00	$500.00

Joint Ex. 1, Para. B.9; Pet. Ex. 2-S, at p. 21.

K. **Tariff Changes.** Paragraph B.10 of the Settlement sets forth the Settling Parties' agreement with respect to NIPSCO's proposed tariff changes. With respect to the Bank Account Capacity Charge, the Settling Parties agreed to a charge of $0.0406 per Therm of capacity per month, representing a 25% increase from the current charge of $0.0325. Joint Ex. 1, Para. B.10(a); Pet. Ex. 2-S, at p. 22.

With respect to recovery of actual UAFG through the GCA, the Settling Parties agreed to decrease the UAFG Percentage cap to 0.90%, representing a decrease from the current UAFG Percentage of 1.04%. Joint Ex. 1, Para. B.10(b); Pet. Ex. 2-S, at p. 22. Ms. Whitehead testified the Settlement addresses the parties' dispute over the UAFG percentage because NIPSCO recovers UAFG through the GCA subject to an agreed-upon cap of 1.04%; the OUCC recommended the maximum annual UAFG recovered through the GCA should be lowered to 0.69%, which is NIPSCO's ten-year average UAFG. The Settling Parties ultimately agreed to lower the cap to the agreed upon 0.90%.

With respect to the UPS Rider, the Settling Parties agreed that NIPSCO will fund 30% of the USP program expenses after funding 100% of the Hardship portion of the program. Joint Ex. 1, Para. B.10(c); Pet. Ex. 2-S, at p. 23. The Settling Parties agreed that NIPSCO's contribution to USP expenses will not exceed $500,000, but Petitioner's administrative expenses are not included in the $500,000.

L. **Stipulation Effect, Scope, and Approval.** Section C of the Settlement makes clear that the Settlement is the result of negotiations and compromise reached during the settlement process. The Settlement expressly states that each of the Settling Parties entered into the agreement solely to avoid future disputes and litigation with attendant inconvenience and expense. The Settling Parties expressly agreed the Settlement 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 the particular issues outlined in the Settlement. Further, Section C explicitly states the Settlement is a compromise and will be null and void unless approved in its entirety without modification of material condition deemed unacceptable to any Settling Party. Section C of the Settlement also recognizes the privileged nature of the settlement communications and reflects other terms typically found in settlement agreements before this Commission.

8. **Commission Discussion and Findings.** Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana 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 Coalition v. PSI Energy*, 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 Coalition*, 664 N.E.2d at 406.

Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement, we must determine whether the evidence in this cause sufficiently supports the conclusions that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such agreement serves the public interest.

All of the agreed-upon components of the stipulated revenue requirement are supported by and shown in Joint Exhibit A to the Stipulation and Settlement and supporting settlement testimony. Therefore, we are able to examine the basis for all of the components of the change in base rates and charges provided for in the Settlement and hereby find they are reasonable for purposes of settlement and supported by the evidence of record.

Further, the Settlement provides a resolution of all issues in this Cause without the time and expenses associated with Petitioner filing rebuttal, intervenors filing cross-answering testimony, and the parties going to hearing. Further, approval of the Settlement eliminates the risks, uncertainty and consumption of time and resources that would otherwise be required for the Commission to issue its final order in this proceeding. The Settlement resolves various disputed issues about Petitioner's forecasted expense levels, depreciation rates, updates, and implementation of rates under Section 42.7, and the appropriate return on equity. The Settlement also addresses certain issues among the Settling Parties for purposes of future proceedings.

Below, the Commission will review and address some of the specific components of the Settlement.

A. **Stipulated Depreciation, Amortization, O&M, Rate Base, and Revenues.** Other than disagreements regarding the appropriate return on equity, the OUCC's recommendation to reduce NIPSCO's forecasted expense levels for purposes of setting rates and the recommendation to adopt a different methodology with respect to depreciation accrual rates were the primary drivers behind the substantial difference between the OUCC and NIPSCO in this Cause. The Industrial Group also challenged NIPSCO's return on equity, the inclusion of certain forecasted O&M expenses, and the calculation of depreciation rates.

i. Depreciation. The OUCC's and Industrial Group's objections to Petitioner's proposed depreciation rates resulted in their recommendations to reduce Petitioner's revenue requirement by $22.8 million and $20.9 million, respectively. For purposes of Settlement, NIPSCO has agreed to use the ALG procedure for the calculation of depreciation rates and has also agreed to an average service life of 68 years for gas distribution services (Account 380), both as recommended by Industrial Group witness Andrews. Otherwise, the depreciation accrual rates set forth on Joint Exhibit B to the Settlement are the rates proposed by NIPSCO witness Spanos in its case-in-chief, except that such rates are calculated using the ALG method as agreed to for purposes of Settlement. We find that the stipulated accrual rates are supported by the evidence in this Cause and are reasonable and in the public interest in the overall context of the settlement.

ii. Amortization. NIPSCO, the Industrial Group and the OUCC proposed various amortization periods for NIPSCO's TDSIC regulatory asset, FMCA regulatory asset, COVID-19 regulatory asset and Cause No. 45621 rate case expense. For purposes of Settlement, the Settling Parties agreed to amortize each of these over a four-year period rather than the various periods as proposed by NIPSCO, the Industrial Group and the OUCC in their respective cases-in-chief. Pub. Ex. 9, at pp. 4-5; Joint Ex. 1, Para. B.3(b). For purposes of Settlement, NIPSCO also agreed to reduce total rate case expense from $1,615,098 to $1,352,043, reflecting a reduction of $63,055 related to lower IT costs as recommended by the OUCC. NIPSCO further agreed to a reduction of $200,000 for reduced litigation costs due to settlement. *Id*. For purposes of Settlement, NIPSCO also agreed that if it files a general rate case before expiration of the four-year amortization period, any unamortized portions will be included in NIPSCO's next rate case. If not already addressed by a rate case order before expiration of the four-year amortization period, NIPSCO agrees to file a revised tariff to remove the annual amortization amounts from base rates. Ultimately, we find these terms of the Settlement to be a reasonable resolution of the disputed items and in the public interest.

iii. O&M. In its case-in-chief, the OUCC recommended a reduction of Petitioner's forecasted O&M expense levels by $7.87 million resulting from the OUCC's recommended reductions of: (i) $2.54 million in gas operations expense; (ii) $1.17 million in corporate service bill; (iii) $60,116 in uncollectible expense; (iv) $2.46 million in Corporate Incentive Plan ("CIP") expense; and (v) $1.62 million in fee free transaction program expenses. Industrial Group witness Michael Gorman also recommended reductions of $6.3 million for labor expense and $10.5 million for CIP expense. For purposes of Settlement, NIPSCO agreed to accept the parties' recommendations with respect to O&M expense, apart from the reductions to CIP expense and labor expense, and NIPSCO partially accepted the OUCC's reduction to gas operations expense, as discussed below. Thus, NIPSCO ultimately agreed to a reduction in Gas Operations, Uncollectible Expense and Fee Free Transaction Expense, for a total reduction of $2,958,602. Joint Ex. 1, Para. B.6; Pet. Ex. 2-S, at p. 13.

We find the Settling Parties' resolution of total O&M expense is within the range of the evidence in this proceeding and we find it to be reasonable. The Settling Parties' stipulation to an overall O&M expense reduction of $2,958,602 reflects a compromise that contributes significantly to the overall reduction of the requested revenue increase. We find this term of the Settlement to be a reasonable resolution of the disputed items and in the public interest.

iv. Rate Base. Neither the OUCC nor the Industrial Group recommended any adjustments to NIPSCO's forecasted rate base of $2,418,669,134, and this is the amount of Net Original Cost Rate Base that is agreed to for purposes of Settlement. Pub. Ex. 9, at p. 3; Joint Ex. 1, Para. B.2(a). Thus, the stipulated rate base amount is reasonable and within the scope of evidence.

v. Revenues. The only issue raised regarding Petitioner's proposed revenues was the OUCC's recommendation that Gas Rent Revenue should be increased by $24,578 from $133,857 to $158,435. Pub. Ex. 2, at p. 1. For purposes of Settlement, and as reflected in Paragraph B.5. of the Settlement, NIPSCO accepted the OUCC's recommendation to increase Gas Rent Revenue by $24,578. Joint Ex. 1, Para. B.5. Thus, we find the total overall pro forma revenue at present rates of $814,519,710 is reasonable in the context of the overall settlement.

B. Cost of Capital.

i. Cost of Equity. The Settling Parties agreed NIPSCO's cost of equity should be 9.85%, representing a reduction from Petitioner's initial request of 10.50% and an increase to the OUCC and intervenors' initial return on equity proposals. Joint Ex. 1, Para. B.2(b); Pet. Ex. 15, at p. 5. OUCC witness Grosskopf testified the OUCC considers the 9.85% cost of equity, representing no change from NIPSCO's currently authorized cost of equity, a fair and reasonable result when combined with other considerations and compromises made in the Settlement. Pub. Ex. 9, at p. 3. The Commission finds the stipulated cost of equity of 9.85% is within the range of the evidence and is reasonable in the context of the overall settlement package.

ii. Capital Structure. NIPSCO's projected investor-supplied capitalization as of December 31, 2022 reflected a forecasted equity ratio of 49.47% and forecasted debt ratio of 36.30%. Pet. Ex. 3, Attach. 3-A-S2, at p. 5. Based on Petitioner's projected capital structure, the stipulated return on equity of 9.85%, and the cost of debt/zero cost capital as filed, the agreed cost of equity and capital structure will produce a WACC of 6.55%. Joint Ex. 1, Para. B.2(b). The Commission finds that the stipulated weighted cost of capital, when multiplied by the stipulated net original cost rate base, produces a fair return for purposes of this case and for earnings test purposes, and is reasonable in the context of the overall settlement and supported by the evidence. We further find that the projected capital structure included in the Settlement will produce a balanced capital structure mix of debt and equity.

C. Taxes.

i. EADIT. For Indiana state tax purposes, there is no restriction on the period over which EADIT must be amortized. Pub. Ex. 9, at p. 5. The Industrial Group proposed a four-year amortization period over which Indiana EADIT could be applied as a credit to Indiana income tax expense. Industrial Group Ex. 1, at p. 23. For purposes of Settlement, the Settling Parties agreed to a four-year amortization period for Indiana EADIT (protected and unprotected), resulting in an increase of $1,744,143 in the annual state tax passback from $305,737 to $2,049,880. Joint Ex. 1, Para. B.4(a). Upon completion of the passback of Indiana (protected and unprotected) EADIT and unprotected federal EADIT approved in Cause No. 44988 ($6,120,309), NIPSCO will make compliance filings in this Cause to increase rates to reflect the cessation of amortization upon the passback of all Indiana EADIT and unprotected federal EADIT, as the case may be. OUCC witness Grosskopf testified the four-year amortization period is consistent with the other amortization periods agreed to in this Cause and accelerates the time over which the Indiana EADIT will be refunded to customers. We find this term of the Settlement is reasonable.

ii. Tax Update Mechanism. In its case-in-chief, NIPSCO proposed a mechanism to capture future tax changes. NIPSCO's proposal would have allowed NIPSCO to adjust its base rates for future changes to the federal income tax rate, Indiana state income tax rate, URT rate or the PUF rate. OUCC witness Grosskopf testified he disagreed with NIPSCO's proposal to automatically update its base rates for future tax changes because the proposal is speculative and premature, and NIPSCO should be required to make a filing setting forth how it proposes to implement future tax rates or fee changes. For purposes of Settlement, NIPSCO agreed to withdraw its request pertaining to future changes in URT or PUF. Pet. Ex. 2-S, at pp. 11-12. NIPSCO further agreed that in the event of future legislation that would change either the federal or state income tax rate, it would seek approval of a new rider in a docketed proceeding to implement related rate changes. *Id*. The new rider would function like the first phase of the Commission's Investigation into the effects of the Tax Cuts and Jobs Act of 2017 in Cause No. 45032. *Id*.

With respect to the new rider, the Settling Parties agreed NIPSCO would have authority to seek approval of a new Tax Rate Modification Mechanism ("TRMM") in a separately docketed proceeding to implement rate changes upon the adoption of a new statutory and/or federal income tax rates. Joint Ex. 1, Para. B.4(b); *Id*. The Settlement further states NIPSCO may seek authority to implement a rate adjustment to reflect the difference between: (1) the amount of federal or state taxes that the given rate or charge was designed to recover based on the tax rate in effect at the time the rate or charge was approved; and (2) the amount of federal or state taxes that would have been embedded in the given rate or charge had the new tax rate applicable to NIPSCO as a result of the new legislation been in effect at the time of approval. *Id*. The Settlement also makes clear that, to the extent new statutory state and federal income tax rates affect NIPSCO's EADIT, NIPSCO may also seek authority to evaluate any related ratemaking effects. NIPSCO may also seek authority to use regulatory accounting, such as regulatory assets or liabilities, for all calculated differences resulting from adoption of new statutory state and federal income tax rates. *Id*.

The Settlement further provides that, while NIPSCO's request for the rider can be made outside of a general rate case, the OUCC, Industrial Group, and SDI reserve all rights to take any position as to the merits of any new rider filing made by NIPSCO's request. Joint Ex. 1, Para. B.4(b)(v).

We find the Settlement as to future changes in income tax rates to be reasonable.

D. Updates and Implementation of Phase 1 and Phase 2 Rates. Neither the OUCC nor the Industrial Group opposed Petitioner's rate base update proposal; however, the OUCC recommended that NIPSCO's forecasted rate base serve as a cap on the actual rate base that is ultimately included in Step 2 rates. Pub. Ex. 1, at p. 2. For purposes of Settlement, NIPSCO agreed that the cap will apply to Total Utility Plant. Joint Ex. 1, Para. B.7(b); Pet. Ex. 2-S, at pp. 18-19. NIPSCO witness Whitehead explained in her settlement testimony that applying the cap to total utility plant will make it easier for NIPSCO to determine which items of utility plant were placed in service after the cap had been reached (and therefore not included in rate base for purposes of this case as a result of the cap). Pet. Ex. 2-S, at pp. 18-19. Ms. Whitehead testified that in all other respects, the calculation of Step 2 Rates remains the same as proposed in NIPSCO's case-in-chief, with rates based upon total original cost rate base, capital structure, and annualized depreciation and amortization expenses at test-year end (December 31, 2022). *Id*. Step 1 will be based upon these same components as of June 30, 2022. *Id*.

The Settlement provides the Settling Parties an agreed process for implementing Phase 1 and Phase 2 rates, which tracks very closely the process this Commission has previously approved in settlements using a forward-looking test period. *Northern Indiana Public Service Company*, Cause No. 44988 (IURC Sept. 18, 2018); *Indiana-American Water Company, Inc.*, Cause No. 45142 (IURC June 26, 2019). The stipulation for Phase 1 rates follows Petitioner's proposal from its case-in-chief. The stipulation for Phase 2 rates adopts a middle ground position between Petitioner's proposal and the OUCC's proposal to cap rate base in Step 2 rates.

For Phase 1 rates, upon issuance of this Order approving the Settlement, Petitioner will file a compliance filing reflecting rates based on the agreed revenue requirement as updated to reflect the original cost of net utility plant in service, actual capital structure and associated annualized depreciation expense as of June 30, 2022. Phase 1 rates will take effect upon submission on an interim-subject-to-refund basis pending the 60-day review process agreed to among the Settling Parties in Paragraph B.7(a) of the Settlement.

For Phase 2 rates, Petitioner will certify its actual total rate base, capital structure, and associated annualized depreciation and amortization expenses at test-year end (December 31, 2022). Step 2 rates will be based on the agreed revenue requirement as of December 31, 2022, as adjusted for Petitioner's certification and reflecting the lesser of (a) NIPSCO's forecasted test-year-end Total Utility Plant as updated in its direct evidence ($4,004,668,454 – Pet. Ex. No. 3, Attach. 3-B-S2 RB Module), or (b) NIPSCO's certified test-year-end Total Utility Plant as of December 31, 2022. Phase 2 rates will also take effect upon submission on an interim-subject-to-refund basis pending the 60-day review process agreed to among the Settling Parties.

Paragraph B.7(c) of the Settlement makes clear that to the extent the actual revenue requirement at either Step 1 or Step 2 differs from the total revenue requirement set forth in Paragraph B.1.(a) of the Settlement ($886,319,992), the difference will be reflected by changing the rates set forth in NIPSCO witness Whitehead's Attachment 2-S-A in an across-the-board fashion.

The Commission finds this term of the Settlement is consistent with prior Commission orders on phased rate implementation in the context of a forward-looking test year and achieves a fair and balanced approach to updating for actuals as of the end of the test year consistent with Indiana law. We do find, however, that one change should be made to the Settling Parties' agreement as to implementation. After the Settlement was filed but before the final evidentiary hearing, Governor Holcomb signed House Bill 1002 into law, which repeals the Utility Receipts Tax effective July 1, 2022. In Petitioner's Response to the Presiding Officers' March 14, 2022 Docket Entry, NIPSCO stated that it would reflect the resulting revenue requirement reduction in its Phase 1 and Phase 2 compliance filings and that, pursuant to the terms of the Settlement, any resulting change in the overall revenue requirement would be reflected as an across-the-board change from the Settlement rates. At the evidentiary hearing, the OUCC indicated it had no objection to this proposal based on its understanding that all rate classes pay URT and that, in calculating the new revenue requirement, NIPSCO will remove URT from the revenue requirement schedules and the new revenue requirement will be allocated using the settlement allocators, resulting in no changes to the settlement allocators. NIPSCO confirmed this understanding at the evidentiary hearing. No party objected to NIPSCO's proposal for addressing the repeal of URT. We find NIPSCO's proposal for reflecting the repeal of URT is reasonable.

E. <u>Revenue Allocation</u>. Paragraph B.8 of the Settlement sets forth the Settling Parties' agreement with respect to cost of service and revenue allocation. In its case-in-chief, NIPSCO proposed to use the Peak & Average Method to allocate Transmission Mains. Pet. Ex. 17, at p. 35. Based on its cost-of-service study, NIPSCO had proposed no increase for Rate 134 and increases capped at 60% of the system average margin increase for Rates 121, 125, and 138. *Id*., at p. 60. The Industrial Group and SDI proposed the continued use of the Design Day Method for the allocation of Transmission Mains. Industrial Group Ex. 3, at p. 3; SDI Ex. 1, at p. 4.

NIPSCO witness Whitehead testified the consumer parties worked together to achieve an equitable balance of the settlement increase, to which NIPSCO ultimately agreed. Pet. Ex. 2-S, at pp. 19-21. Ms. Whitehead explained that in essence, the agreement is that Rate 128 would receive an increase approximating what it would have received with an across-the-board increase. The split of the Rate 128 increase among DP and HP was negotiated between intervenors representing those two groups of customers and was agreeable to the remaining Settling Parties. *Id*. Rate 134 would receive no increase. Rates 121, 125, and 138 were set around 65% of the system average margin increase. The balance is Rates 111 and 115. Ms. Whitehead testified that given the divergent views on cost of service and mitigation, this is a fair and equitable allocation. *Id*.

Further, with respect to the DP subclass in rate 128, the Settling Parties agreed that the second-tier threshold for the transportation charge will be changed from 300,000 to 100,000 therms (with no change to the HP tiers), with the second-tier rate remaining the same as the second-tier rate for HP (NIPSCO's filed position). Pub. Ex. 9, at p. 9.

Ultimately, for purposes of Settlement, the Settling Parties stipulated to the allocation of the agreed $71.8 million revenue increase between classes as follows:

<table>
<tr><th></th><th>Current Distribution Margin</th><th>Revenue Increase</th><th>Percentage Increase on Margin</th></tr>
<tr><td>Rate 111</td><td>$295,326,125</td><td>$52,960,388</td><td>17.9%</td></tr>
<tr><td>Rate 115</td><td>$2,404,167</td><td>$399,321</td><td>16.6%</td></tr>
<tr><td>Rate 121</td><td>$99,061,233</td><td>$9,729,065</td><td>9.8%</td></tr>
<tr><td>Rate 125</td><td>$12,859,523</td><td>$1,242,227</td><td>9.7%</td></tr>
<tr><td>Rate 128 DP</td><td>$9,191,556</td><td>$3,676,622</td><td rowspan="2">15.7%</td></tr>
<tr><td>Rate 128 HP</td><td>$35,286,309</td><td>$3,294,500</td></tr>
<tr><td>Rate 134</td><td>$194,747</td><td>$0</td><td>0.0%</td></tr>
<tr><td>Rate 138</td><td>$5,154,021</td><td>$497,877</td><td>9.7%</td></tr>
<tr><td>Total</td><td></td><td>$71,800,000</td><td></td></tr>
</table>

Joint Ex.1, Para. B.8.

Further, the TDSIC allocators agreed to by the Settling Parties are set forth on Joint Exhibit C attached to the Settlement. OUCC witness Grosskopf testified the allocation of the revenue increase agreed to by the Settling Parties is the result of negotiations intended to acknowledge fair and reasonable treatment for all classes. Pub. Ex. 9, at p. 10.

The evidence supports the stipulations on revenue allocation for the various customer classes and the Commission finds the negotiated compromise on revenue allocation is reasonable and should be approved.

F. <u>Rate Design and Tariff Changes</u>. For purposes of Settlement, NIPSCO agreed to cap increases to customer classes 121, 125, and 138 (General Service Small, General Service Large, and General Transport) in order to recognize the benefit of the Settlement, and to reduce the subsidy being paid by these classes. Pub. Ex. 9, at p. 10. The agreed-upon rate design (together with revenue proof) is attached with NIPSCO witness Whitehead's settlement testimony as Attachment 2-S-A. Pet. Ex. 2-S, at p. 23. Ms. Whitehead testified the rate design set forth in Attachment 2-S-A is based upon the Settlement revenue requirement and stipulated revenue allocation at Step 2. She further explained the actual rates will be based upon the Step 2 compliance filing as set forth in the Settlement. *Id*.

In testimony, two issues were disputed regarding NIPSCO's proposed tariff changes: The monthly customer charge and the bank account capacity charge. Pub. Ex. 9, at p. 9. With respect to the monthly customer service charge, the OUCC recommended the Commission reject NIPSCO's proposed monthly customer charge for Rates 111, 115, 121, and 125 and approve a customer charge increase not to exceed 50% of the approved margin percentage increase. Pub. Ex. 7, at p. 2. For purposes of Settlement, the Settling Parties agreed to the following customer charge increases:

Residential	\$14.00 to \$16.50
Multi Family	\$17.50 to \$20.75
General Service Small	\$53.00 to \$67.00
General Service Large	\$400.00 to \$500.00

Otherwise, the revenue allocation as agreed to by the Settling Parties in Paragraph B.8. of the Settlement is as set forth in Attachment 2-S-A. Joint Ex. 1, Para. B.9. All other monthly customer charges were accepted as proposed by NIPSCO. NIPSCO witness Whitehead testified these customer charges are reasonable because while NIPSCO requested and advocated for higher customer charges, NIPSCO recognized the OUCC's position. Pet. Ex. 2-S, at pp. 21-22. She testified the agreed-upon customer charges represent a very gradual movement to straight fixed variable pricing, and are equal to the customer charges that were recently implemented for CenterPoint Indiana North and South in their rate cases (Cause Nos. 45468 and 45447). Thus, Ms. Whitehead testified these customer charges are within the scope of the evidence and are in the public interest. *Id*.

The Settling Parties also agreed on other tariff changes. With respect to the bank capacity charge, the only other issue disputed in testimony, the Settling Parties agreed to increase the bank capacity charge by 25%, which would represent a bank capacity charge of \$0.0406 per therm per month. Joint Ex. 1, Para. B.10.(a); Pet. Ex. 2-S, at p. 22. NIPSCO witness Whitehead testified the agreed-upon bank capacity charge represents a gradual increase which is consistent with NIPSCO's goal to move the charge closer to what NIPSCO believes is the true cost of providing this service. Pet. Ex. 2-S, at p. 22.

With respect to the UAFG Percentage, NIPSCO recovers the UAFG through the GCA subject to an agreed-upon cap of 1.04%. *Id.* The OUCC recommended that this cap should be lowered to 0.69%, which is NIPSCO's ten-year average UAFG. *Id.* For purposes of Settlement, the Settling Parties agreed to lower the maximum annual UAFG percentage to be used in NIPSCO's GCA from 1.04% to 0.90%. Joint Ex. 1, Para. B.10.(b); Pet. Ex. 2-S, at p. 22.

With respect to the USP Rider, the Settling Parties agreed NIPSCO will fund 30% of the USP program expenses after funding 100% of the Hardship portion of the program. Joint Ex. 1, Para. B.10.(c); Pet. Ex. 2-S, at p. 23; Pub. Ex. 9, at p. 8. Further, the Settling Parties agreed NIPSCO's contribution to USP expenses will not exceed $500,000, but NIPSCO's administrative expenses will not be counted towards that amount. *Id.*

We find that these settlement terms are within the scope of the evidence and are in the public interest.

9. Conclusion. Based upon our review of the record, the Commission finds the Settlement represents a reasonable resolution of the issues.

The Commission finds that the projected original cost of Petitioner's gas utility properties as of December 31, 2022 is as follows:

Description	**Pro forma As of December 31, 2022**
Rate Base	
Utility Plant	$ 3,815,305,221
Common Allocated	189,363,233
Total Utility Plant	**$ 4,004,668,454**
Accumulated Depreciation and Amortization	(1,578,834,102)
Common Allocated	(124,923,724)
Total Accumulated Depreciation and Amortization	**$ (1,703,757,826)**
Net Utility Plant	**$ 2,300,910,628**
Cause No. 44988 Regulatory Assets	6,195,174
TDSIC Regulatory Asset	11,652,922
FMCA Regulatory Asset	14,584,863
Materials & Supplies	13,684,877
Gas Stored Underground – Current A/C 164 (13-month avg.)	66,691,249
Gas Stored Underground – Non-Current A/C 117	4,949,422

Total Rate Base	**$ 2,418,669,134**

The Commission concludes that the Settlement is reasonable and in the public interest. Accordingly, the Settlement is approved. Petitioner is authorized to implement rates and charges in two phases as described in the Settlement Agreement to produce total annual operating revenue of $886,319,992. This revenue is estimated to afford Petitioner the opportunity to earn net operating income of $158,422,828.

10. Effect of Settlement. Consistent with the terms of the Settlement, the Settlement is not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce its terms; consequently, with regard to future citation of the Settlement or of this Order, we find our approval herein should be treated in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434 (IURC March 19, 1997).

11. Confidentiality. Petitioner filed a motion for protective order showing documents to be submitted to the Commission pursuant to 170 IAC 1-5-15 were to be treated as confidential and protected from disclosure to the public under Ind. Code § 5-14-3-4 and Ind. Code § 8-1-2-29. The Presiding Officers granted preliminary confidential treatment for Petitioner's motion by Docket Entry dated October 21, 2021. We now find all such information previously granted preliminary confidential treatment to be confidential and exempt from public access and disclosure by the Commission under Ind. Code § 5-14-3-4 and Ind. Code § 8-1-2-29.

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

1. The March 2, 2022 Stipulation and Settlement Agreement, a copy of which is attached to this Order, is approved in its entirety.

2. Subject to the rate implementation process set forth in the Settlement Agreement, Petitioner is authorized over the course of the future test year to adjust and increase its base rates and charges for natural gas utility service to produce an increase in total revenues of $71,800,282 in accordance with the findings herein which rates and charges shall be designed to produce total annual operating revenues of $886,319,992 which are expected to produce annual net operating income of up to $158,422,828.

3. Petitioner is authorized to implement the authorized rate increase in two phases to be implemented as set forth in Ordering Paragraph Nos. 4 and 5 below.

4. For Phase 1, Petitioner shall file new schedules of rates and charges with the Energy Division of the Commission on the basis set forth in Finding Paragraph No. 8.D, reflecting the total revenue requirement set forth in Ordering Paragraph No. 2 with adjustments to: (a) rate base to reflect actual net utility plant in service as of June 30, 2022; (b) return to reflect actual capital structure as of the same date; (c) expenses to reflect annualized depreciation and amortization expense on utility plant in service as of June 30, 2022; and (d) gross revenue conversion resulting from the change in revenue requirement caused by these adjustments. Petitioner shall also file a schedule setting forth the actual net utility plant in service as of June 30, 2022, an affidavit certifying that such investment

is actually in service, a calculation of actual annualized depreciation and amortization expense thereon as of June 30, 2022, and Petitioner's actual capital structure as of that same date. Petitioner's compliance filing shall also reflect the change in revenue requirement resulting from the repeal of the URT. Petitioner's new schedules of rates and charges shall be effective upon filing on an interim-subject-to-refund basis pending the 60-day review process described in Finding Paragraph No. 8.D.

5. For Phase 2, Petitioner shall file new schedules of rates and charges with the Energy Division of the Commission on the basis set forth in Finding Paragraph No. 8.D, reflecting the total revenue requirement set forth in Ordering Paragraph No. 2 with adjustments to: (a) rate base to reflect actual net utility plant in service as of December 31, 2022, except that total utility plant shall not exceed $4,004,668,454; (b) return to reflect actual capital structure as of the same date; (c) expenses to reflect annualized depreciation and amortization expense on utility plant in service as of December 31, 2022; and (d) gross revenue conversion resulting from the change in revenue requirement caused by these adjustments. Petitioner shall also file a schedule setting forth the actual net utility plant in service as of December 31, 2022, an affidavit certifying that such investment is actually in service, a calculation of actual annualized depreciation expense thereon as of December 31, 2022, and Petitioner's actual capital structure as of that same date. Petitioner's compliance filing shall also reflect the change in revenue requirement resulting from the repeal of the URT. Petitioner's new schedules of rates and charges shall be effective upon filing on an interim-subject-to-refund basis pending the 60-day review process described in Finding Paragraph No. 8.D.

6. All schedules of rates and charges submitted under Ordering Paragraph Nos. 4 and 5, shall be developed according to the agreed-upon revenue allocation and rate design as set forth in Paragraph Nos. 8 and 9 of the Settlement Agreement and otherwise in the manner described by the terms of the Settlement Agreement.

7. The proposed Gas Service Tariff, Original Volume No. 9 as filed on September 29, 2021, is approved consistent with the Stipulation and Settlement Agreement and this Order inclusive of the associated General Rules and Regulations, Rate Release Form, and Standard Contract. NIPSCO shall file the tariff under this Cause for approval by the Commission's Energy Division.

8. The depreciation accrual rates set forth in Joint Exhibit B to the Settlement Agreement are approved.

9. Regulatory assets for TDSIC, FMCA, COVID, and Cause No. 45621 Gas Rate Case Expense, shall be amortized over a period of four years from the date of this Order. Further, the remaining Cause No. 44988 Regulatory Asset shall be amortized over 33 months. If not already addressed by an intervening base rate order, after completion of the 33-month period, Petitioner shall make a compliance filing that will reflect the reduction in amortization expense for the 44988 Regulatory Asset. Further, if Petitioner files a general rate case before the expiration of the four-year amortization period, any unamortized portion will be rolled into Petitioner's next rate case. If not already addressed by an intervening base rate case order before the expiration of the four-year amortization period, Petitioner shall file a revised tariff to remove the annual amortization portion from base rates.

10. For purposes of future TDSIC proceedings, the revenue allocations by class set forth in Joint Exhibit C to the Settlement Agreement are approved.

11. Petitioner shall fund USP program expenses after funding 100% of the Hardship portion of the program as discussed in Finding No. 8.F. Petitioner's contribution to USP expenses shall not exceed $500,000, but Petitioner's administrative expenses are not included for purposes of the $500,000 contribution.

12. Both bad debt expense associated with the cost of gas and UAFG shall continue to be tracked and recovered through Petitioner's GCA. The bad debt percentage recovered through the GCA shall be 0.4234%. The maximum annual UAFG recovered shall be 0.90%.

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

HUSTON, FREEMAN, KREVDA, AND ZIEGNER CONCUR:

APPROVED: JUL 27 2022

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: 2022.07.27 10:24:04 -04'00'

Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR GAS UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ITS GAS PLANT IN SERVICE; (4) APPROVAL OF MECHANISM TO MODIFY RATES PROSPECTIVELY FOR CHANGES IN FEDERAL OR STATE INCOME TAX RATES, UTILITY RECEIPTS TAX RATES, AND PUBLIC UTILITY FEE RATES; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (6) AUTHORITY TO IMPLEMENT TEMPORARY RATES CONSISTENT WITH THE PROVISIONS OF IND. CODE § 8-1-2-42.7.	)	CAUSE NO. 45621

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 2nd day of March, 2022, by and between Northern Indiana Public Service Company LLC ("NIPSCO"), the NIPSCO Industrial Group ("Industrial Group"),[1] Steel Dynamics, Inc. ("SDI"), and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"). The Settling Parties, solely for purposes of

[1] The Industrial Group is comprised of BP Products North America, Inc., Cargill, Inc., Cleveland-Cliffs Inc., General Motors LLC, Linde, NLMK Indiana, United States Steel Corporation, and USG Corporation.

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 general gas rate case proceeding currently pending in Cause No. 45621 as among the Settling Parties. The Settling Parties agree that NIPSCO's requested relief in this Cause should be granted in its entirety except as expressly modified herein.

A. Background

1. NIPSCO's Current Basic Rates and Charges. The Commission's September 19, 2018 Order in Cause No. 44988 (the "44988 Rate Case Order") approved a Stipulation and Settlement Agreement among NIPSCO, the Indiana Office of Utility Consumer Counselor ("OUCC"), and the majority of intervenors in that proceeding. The 44988 Rate Case Order approved a three step change in basic rates and charges. Step 1 rates took effect on October 1, 2018 based upon rate base as of June 30, 2018. Step 2 rates took effect March 1, 2019, based upon rate base as of December 31, 2018. Step 3 rates took effect January 1, 2020 to reduce rates so as to pass back unprotected excess Accumulated Deferred Income Taxes resulting from the Tax Cuts and Jobs Act of 2017 over a 12-year period.

2. NIPSCO's Alternative Regulatory Plan. NIPSCO has operated under the terms of an approved alternative regulatory plan ("ARP") under Ind. Code § 8-1-2.5 since the Commission's Order dated October 8, 1997 in Cause No. 40342. The ARP was renewed and modified in Cause No. 41338, consolidated Cause Nos. 42800 and 42884, and Cause No. 43837. The ARP was most recently extended and modified and became a permanent part of NIPSCO's tariff on March 15, 2012 in Cause No. 44081.

3. NIPSCO's Gas Cost Adjustment ("GCA") Proceedings. Pursuant to Ind. Code § 8-1-2-42(g), NIPSCO files a quarterly Gas Cost Adjustment ("GCA") proceeding in Cause No. 43629-GCA-XXX to adjust its rates to account for fluctuation in its gas costs. The cost of bad debt expense associated with the cost of gas is reflected in NIPSCO's GCA. Pursuant to the Commission's November 4, 2010 Order in Cause No. 43894 and through an annual update to Appendix E – Unaccounted for Gas Percentage ("UAFG"), NIPSCO also recovers through its GCA the actual cost of UAFG up to a maximum percentage of 1.04%. NIPSCO proposes to continue both of these recoveries through the GCA as modified by the terms of this Agreement.

4. NIPSCO's Other Tracking Mechanisms.

(a) Pursuant to the Commission's December 7, 2011 Order in Cause No. 44094, NIPSCO files an annual update to Appendix D – Universal Service Program

(USP) Factors in a compliance filing in Cause No. 44094 to be applicable for the billing month of October.

(b) Pursuant to the Commission's December 28, 2011 Order in Cause No. 44001, NIPSCO files an annual proceeding in Cause No. 44001-GDSM-XX for recovery of program costs associated with approved demand side management and energy efficiency programs through its Rider 172 – Gas Demand Side Management (GDSM) Rider and Appendix C - GDSM Factors (the "GDSM Mechanism").[2]

(c) Pursuant to the Commission's January 28, 2015 Order in Cause No. 44403-TDSIC-1, NIPSCO filed a semi-annual proceeding in Cause No. 44403-TDSIC-XX to recover 80% of approved capital expenditures and TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution, and storage system improvements ("TDSIC Projects") through its Rider 188 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix F – Transmission, Distribution and Storage System Improvement Charge Adjustment Factor ("TDSIC Mechanism"). Pursuant to the Commission's July 22, 2020 Order in Cause No. 45330, NIPSCO now files the TDSIC Mechanism in Cause No. 45330-TDSIC-XX.

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2 The Commission's May 9, 2007 Order in Cause No. 43051 initially approved the GDSM Mechanism. The Commission's December 28, 2011 Order in Cause No. 44001 approved NIPSCO's request to change to a semi-annual reconciliation. The Commission's February 22, 2017 Order in Cause No. 44001-GDSM-10 approved NIPSCO's request to change from a semi-annual to annual filing. The Commission's November 21, 2018 Order in Cause No. 45012 approved NIPSCO's request for recovery of lost revenues through the GDSM Mechanism.

(d) Pursuant to the Commission's September 19, 2018 Order in Cause No. 45007, NIPSCO filed a semi-annual proceeding in Cause No. 45007-FMCA-XX to recover 80% of approved federally mandated costs through its Rider 190 – Federally Mandated Cost Adjustment Rider and Appendix G – FMCA Factors ("FMCA Mechanism"). Pursuant to the Commission's December 1, 2021 Order in Cause No. 45560, NIPSCO now files the FMCA Mechanism in Cause No. 45560-FMCA-XX.

5. <u>This Proceeding</u>. On September 29, 2021, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to increase its retail rates and charges for gas utility service through the phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders; (3) approving revised depreciation rates applicable to its gas plant in service; (4) approving a mechanism to modify rates prospectively for changes in federal or state income tax rates, utility receipts tax ("URT") rates, and public utility fee ("PUF") rates; (5) approving accounting relief; (6) authorizing NIPSCO to implement temporary rates; and (6) other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on September 29, 2021. On January 20, 2022, the OUCC and intervenors filed their respective cases-in-chief.

As discussed within NIPSCO's Verified Petition, and the testimony of various parties including NIPSCO, this rate case filing was driven by several developments subsequent to the 44988 Rate Case Order. Since the 44988 Rate Case Order, NIPSCO's cost of providing service has increased. NIPSCO has and must continue to make significant capital expenditures for additions, replacements, and improvements to its Utility Property, in compliance with various applicable state and federal pipeline safety requirements and to maintain safe and reliable service. In addition, changes in NIPSCO's Utility Property warrant the implementation of revised depreciation rates. Further, NIPSCO has and must continue to incur increasing operations and maintenance expenses in order to maintain safe and reliable service.

6. NIPSCO's Current Depreciation and Accrual Rates. NIPSCO's current gas depreciation rates are based on the depreciation study approved in the 44988 Rate Case Order. NIPSCO's current common and electric depreciation rates and last common and electric depreciation study were approved in the Commission's December 4, 2019 Order in Cause No. 45159.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement: The Settling Parties agree that NIPSCO's base rates will be designed to produce revenue at proposed rates of $886,319,992, as adjusted for the Rate Base Update Mechanism set forth in Paragraph B.7. This Revenue Requirement represents an increase of $71,800,282, which is a decrease of $37,891,687 (35%) from the amount requested by NIPSCO in its Case-in-chief ($109,691,969). Joint

Exhibit A attached hereto represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending December 31, 2022.

(b) Net Operating Income: Subject to the Rate Base Update Mechanism set forth in Paragraph B.7., 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 $158,422,828.

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

(a) Original Cost Rate Base. NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement and the Rate Base Update Mechanism set forth in Paragraph B.7., the Settling Parties agree that NIPSCO should be authorized a fair return of $158,422,828 yielding an overall return for earnings test purposes of 6.55%, based upon: (a) a Net Original Cost Rate Base of $2,418,669,134; and (b) NIPSCO's forecasted capital structure, including an authorized return on equity ("ROE") of 9.85%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.85% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	% of Total	Cost %	WACC %
Common Equity	49.47%	9.85%	4.87%
Long-Term Debt	36.30%	4.52%	1.64%
Customer Deposits	0.84%	4.64%	0.04%
Deferred Income Taxes	18.66%	0.00%	0.00%
Post-Retirement Liability	0.34%	0.00%	0.00%
Prepaid Pension Asset	-5.64%	0.00%	0.00%
Post-1970 ITC	0.01%	7.59%	0.00%
Totals	**100.0%**		**6.55%**

The Settling Parties agree that fair return will be calculated based upon the actual capital structure and rate base as described in the Rate Base Update Mechanism set forth in Paragraph B.7.

3. Depreciation and Amortization Expense.

(a) Depreciation Expense. The Settling Parties agree that the depreciation accrual rates will use the Average Life Group procedure for the calculation of depreciation rates with an average service life of 68 years for its gas distribution services (Account 380), resulting in a pro forma adjustment of $20.9 Million. The resulting depreciation accrual rates are shown in Joint Exhibit B. NIPSCO will continue to use the depreciation rates applicable to its common plant as approved by the Commission in NIPSCO's last electric general rate proceeding in Cause No. 45159.

(b) Amortization Expense. The Settling Parties agree to a projected Cause No. 45621 Gas Rate Case Expense regulatory asset balance of $1,352,043 reflecting (i) a $63,055 reduction to the Billing System New Rate Implementation component (from $200,000 to $136,945); and (ii) a $200,000 reduction to reflect reduced costs due to settlement. The Settling Parties agree to Petitioner's proposed 33-month amortization period for the remaining Cause No. 44988 regulatory asset (rate case expense and then-deferred TDSIC balance) (the "44988 Regulatory Asset"). The Settling Parties also agree to a 4-year amortization period for TDSIC, FMCA, COVID, and Cause No. 45621 Gas Rate Case Expense regulatory assets, resulting in a reduction of $1,153,883 in Amortization Expense. If not already addressed by an intervening base rate order, after the completion of the 33-month period, NIPSCO agrees to make a compliance filing that will reflect the reduction in amortization expense for the 44988 Regulatory Asset. After the completion of the four (4) year period, NIPSCO agrees to make a compliance filing that will reflect the reduction in amortization expense for TDSIC, FMCA and COVID regulatory assets, as well as Cause No. 45621 Rate Case Expense. If NIPSCO files a general rate case before the expiration of the amortization period of four (4) years, any unamortized TDSIC, FMCA, COVID or Cause No. 45621 Gas Rate Case Expense regulatory asset balances will be rolled into NIPSCO's next rate case.

4. Taxes.

(a) The Settling Parties agree to a 4-year amortization period for Indiana excess accumulated deferred income taxes ("EADIT") (protected and unprotected), resulting in an increase of $1,744,143 in the annual state tax passback from $305,737 to $2,049,880. Upon completion of the passback of Indiana (protected and unprotected) EADIT and unprotected federal EADIT approved in Cause No. 44988 ($6,120,309), NIPSCO will make compliance filings in this Cause to increase rates to reflect the cessation of amortization upon the passback of all Indiana EADIT and unprotected federal EADIT, as the case may be.

(b) The Settling Parties agree to the following with respect to NIPSCO's proposal for future modifications to State or Federal income tax, Public Utility Fee, and Indiana Utility Receipts Tax rates:

(i) NIPSCO is authorized to seek approval of a new Tax Rate Modification Mechanism ("TRMM") in a separately docketed proceeding to implement rate changes upon the adoption of new statutory state and/or federal income tax rates, if and when they occur;

(ii) As a part of the proposed Tax Rate Modification Mechanism, NIPSCO may seek authority to implement a rate adjustment to reflect the difference between: (1) the amount of federal or state taxes that the given rate or charge was designed to recover based on the tax rate in effect at the time the rate or charge was approved; and (2) the amount of federal or state taxes that would have been embedded in the given rate or charge had the new tax rate applicable to NIPSCO as a result of the new legislation been in effect at the time of approval;

(iii) To the extent new statutory state and federal income tax rates affect its EADIT, NIPSCO may also seek authority to evaluate any related ratemaking effects;

(iv) NIPSCO may also seek authority to use regulatory accounting, such as regulatory assets or liabilities, for all calculated differences resulting from adoption of new statutory state and federal income tax rates until such time as such new tax rates are reflected in NIPSCO's rates; and

(v) A filing made by NIPSCO pursuant to this Paragraph B.4.b. may be made outside of a general rate case. Otherwise, the OUCC, Industrial Group, and SDI reserve all rights to take any position as to the merits of NIPSCO's request.

(vi) Other than as provided in this Paragraph B.4.b., NIPSCO is withdrawing its request for approval of a mechanism to modify rates prospectively for changes in federal or state income tax, utility receipts tax, and public utility fees.

5. Operating Revenues. The Settling Parties stipulate that Gas Rent Revenue should be increased by $24,578 from $133,857 to $158,435 as proposed by the OUCC.

6. O&M Expenses: The Settling Parties stipulate that NIPSCO's forecasted pro forma O&M Expenses should be decreased by $2,958,602, as follows:

(a) Gas Operations (Adjustment OM 2): Reduction of $1,275,000 from $45,092,165 to $43,817,165, to address the OUCC's proposal to decrease Adjustment OM 2A (Line Locates / Mitigate Damages) and Adjustment OM 2B (Gas Measurement & Transmission).

(b) Uncollectible Expense (Adjustment OM 11): Reduction of $60,116 from $2,374,129 to $2,314,013, as proposed by the OUCC.

(c) Fee Free Transaction (Adjustment OM 21): Reduction of $1,623,486 representing the entire adjustment.

7. Rate Base Update Mechanism. The Settling Parties agree that NIPSCO should be authorized to modify its base rates and charges for natural gas utility service in two steps as described herein. The Settling Parties agree to the following process for the implementation of rates in two steps:

(a) Step 1 Rates. The first change in rates will be based on the agreed revenue requirement as adjusted to reflect the actual original cost of NIPSCO's rate base, actual capital structure, and associated annualized depreciation and amortization expense as of June 30, 2022 ("Phase 1"). Following issuance of a Final Order in this Cause approving this Agreement, Phase 1 rates will go into effect upon submission on an interim subject to refund basis pending the 60-day review process as described herein. NIPSCO will certify its actual total rate base, capital structure, and associated annualized depreciation and amortization expenses as of June 30, 2022 and implement base rates using the forecasted results of operation for the test year as found in the Order. If needed to resolve any objections, the Commission will conduct a hearing and rates would be trued up, retroactive to the date such rates were put into place.

(b) Step 2 Rates. NIPSCO will certify its actual total rate base, capital structure, and associated annualized depreciation and amortization expenses at test-year end (December 31, 2022). Step 2 rates will be based on the agreed revenue requirement as of December 31, 2022, as adjusted for this certification and reflecting the lesser of (a) NIPSCO's forecasted test-year-end Total Utility Plant as updated in its direct evidence ($4,004,668,454 – Pet. Ex. No. 3, Attachment 3-B-S2 RB Module), or (b) NIPSCO's certified test-year-end Total Utility Plant as of December 31, 2022. Step 2 rates would take effect immediately upon filing on an interim-subject-to-refund basis, with other parties being offered a period of 60 days to review and present any objections. If needed to resolve any objections, the Commission will conduct a hearing and rates would be trued up, retroactive to the date such rates were put into place. To the extent any additions to Utility Plant are excluded from net original cost rate base because NIPSCO's total Utility Plant exceeds $4,004,668,454, NIPSCO shall include with its submission a list of the work orders which have been placed in service but which are not being included in rate base in this Cause. For purposes of this Paragraph B.7., "certify" means NIPSCO has determined that it has completed the amount of plant indicated in its certification and the corresponding plant additions have been placed in service and are used and useful in providing utility service as of the date of certification. NIPSCO will serve all Settling Parties with its certification.

(c) To the extent the actual revenue requirement resulting from either paragraph (a) or (b) of this section is different from $886,319,992 as provided in Paragraph B.1(a) herein, the difference shall be reflected by changing the rates set forth in NIPSCO Witness Whitehead's Attachment 2-S-A in an across-the-board fashion.

8. Revenue Allocation. The Settling Parties stipulate to the allocation of the agreed $71.8 Million revenue increase between classes as shown below.[3] The TDSIC allocators are as shown on Joint Exhibit C attached hereto.

	Current Distribution Margin	Revenue Increase	Percentage Increase on Margin
Rate 111	$295,326,125	$52,960,388	17.9%
Rate 115	$2,404,167	$399,321	16.6%
Rate 121	$99,061,233	$9,729,065	9.8%
Rate 125	$12,859,523	$1,242,227	9.7%
Rate 128 DP	$9,191,556	$3,676,622	15.7%
Rate 128 HP	$35,286,309	$3,294,500	
Rate 134	$194,747	$0	0.0%
Rate 138	$5,154,021	$497,877	9.7%
		$71,800,000	

[3] Rounds the actual agreed revenue increase of $71,800,282.

The Settling Parties agree that the Rate 128 – Distribution Pressure subclass will be capped at a 40% increase, resulting in an allocation for Rate 128 – Distribution Pressure of $3,676,622 and Rate 128 – High Pressure of $3,294,500.

The Settling Parties stipulate that no cost-of-service methodology is being adopted or endorsed by virtue of the Settlement.

With respect to the DP subclass in Rate 128, the Settling Parties agree that the second tier threshold for the transportation charge will be changed from 300,000 to 100,000 therms (with no change to the HP tiers), with the second tier rate remaining the same as the second tier rate for HP, per NIPSCO's filed position.

9. Rate Design. In addition to the customer charge increases already agreed to in testimony, the Settling Parties agree to the following customer charge increases:

Residential:	$14.00 to $16.50
Multi Family:	$17.50 to $20.75
General Service Small:	$53.00 to $67.00
General Service Large:	$400.00 to $500.00

Otherwise, the allocation of the revenue increase by class in Paragraph 8 shall be as set forth in by NIPSCO Witness Whitehead in Attachment 2-S-A. .

10. Tariff Changes.

(a) Bank Account Capacity Charge: The Settling Parties agree to a Bank Account Capacity Charge of $0.0406 per Therm of capacity per month, representing a 25% increase from the current charge of $0.0325.

(b) Unaccounted for Gas (UAFG) Percentage: For purposes of recovery of actual UAFG through the GCA, the Settling Parties agree to decrease the UAFG Percentage cap to 0.90%, representing a decrease from the current UAFG Percentage of 1.04%.

(c) Universal Service Program (USP) Rider: The Settling Parties agree that NIPSCO will fund 30% of the USP program expenses after funding 100% of the Hardship portion of the program. NIPSCO's contribution to USP expenses will not exceed $500,000, but the Company's administrative expenses are not included in the $500,000 contribution.

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

preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

3. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. Moreover, 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. 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 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. 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. The Settling Parties further agree that the respective cases-in-chief of NIPSCO, the OUCC, the Industrial Group, and SDI may be admitted into the evidentiary record and each of the Settling Parties waives cross examination with respect thereto.

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 2nd day of March, 2022.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

Tiffany Murray
Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor

NIPSCO Industrial Group

Todd Richardson

Steel Dynamics, Inc.

____

Damon E. Xenopoulos
Principal
Stone Mattheis Xenopoulos & Brew, PC

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2022

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S2 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C-S2-S Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 711,775,365		REV, Col A	$ 814,519,710	71,800,282	PF-1-S2-S	$ 886,319,992
3	Pro forma Adjustments December 31, 2020		21,042,617	REV, Col B				
4	Budget Adjustments December 31, 2021		39,127,033	REV, Col D				
5	Budget Adjustments December 31, 2022		5,535,979	REV, Col F				
6	Ratemaking Adjustments December 31, 2022		37,014,138	REV, Col H				
7	Settlement Ratemaking Adjustments December 31, 2022		24,578	REV, Col J[2]				
8	Total Operating Revenue	$ 711,775,365	$ 102,744,345		$ 814,519,710	$ 71,800,282		$ 886,319,992
9	**Gas Costs (Trackable)**							
10	Gas Cost (Actual / Pro Forma)	$ 272,995,605		COGS, Col A	$ 348,721,758	-		$ 348,721,758
11	Pro forma Adjustments December 31, 2020		13,038,036	COGS, Col B				
12	Budget Adjustments December 31, 2021		28,170,131	COGS, Col D				
13	Budget Adjustments December 31, 2022		(11,826,877)	COGS, Col F				
14	Ratemaking Adjustments December 31, 2022		46,344,863	COGS, Col H				
15	Total Gas Costs	$ 272,995,605	$ 75,726,153		$ 348,721,758	$ -		$ 348,721,758
16	**Gross Margin**	$ 438,779,760	$ 27,018,192		$ 465,797,952	$ 71,800,282		$ 537,598,234
17	**Operations and Maintenance Expenses**							
18	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 226,187,401		O&M, Col A	$ 220,463,202	203,981	PF-2-S2-S	$ 220,667,183
19	Pro forma Adjustments December 31, 2020		3,840,998	O&M, Col B				
20	Budget Adjustments December 31, 2021		(3,522,408)	O&M, Col D				
21	Budget Adjustments December 31, 2022		(4,040,584)	O&M, Col F				
22	Ratemaking Adjustments December 31, 2022		956,397	O&M, Col H				
23	Settlement Ratemaking Adjustments December 31, 2022		(2,958,602)	O&M, Col J[2]				
24	Total Operations and Maintenance Expense	$ 226,187,401	$ (5,724,199)		$ 220,463,202	$ 203,981		$ 220,667,183
25	**Depreciation Expense**							
26	Depreciation Expense (Actual / Pro Forma)	$ 67,838,244		DEPR, Col A	$ 76,632,613			$ 76,632,613
27	Pro forma Adjustments December 31, 2020		(314,778)	DEPR, Col B				
28	Budget Adjustments December 31, 2021		10,012,814	DEPR, Col D				
29	Budget Adjustments December 31, 2022		6,229,000	DEPR, Col F				
30	Ratemaking Adjustments December 31, 2022		13,741,136	DEPR, Col H				
31	Settlement Ratemaking Adjustments December 31, 2022		(20,873,803)	DEPR, Col J[2]				
32	Total Depreciation Expense	$ 67,838,244	$ 8,794,369		$ 76,632,613	$ -		$ 76,632,613

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2022

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S2 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C-S2-S Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
33	**Amortization Expense**							
34	Amortization Expense (Actual / Pro Forma)	$ 5,832,272		AMTZ, Col A	$ 23,408,115			$ 23,408,115
35	Pro forma Adjustments December 31, 2020		2,420,052	AMTZ, Col B				
36	Budget Adjustments December 31, 2021		1,606,828	AMTZ, Col D				
37	Budget Adjustments December 31, 2022		2,713,535	AMTZ, Col F				
38	Ratemaking Adjustments December 31, 2022		11,989,311	AMTZ, Col H				
39	Settlement Ratemaking Adjustments December 31, 2022		(1,153,883)	AMTZ, Col J[2]				
40	Total Amortization Expense	$ 5,832,272	$ 17,575,843		$ 23,408,115	$ -		$ 23,408,115
41	**Taxes**							
42	**Taxes Other than Income**							
43	Taxes Other than Income (Actual / Pro Forma)	$ 31,241,852		OTX, Col A	$ 29,754,919			$ 29,754,919
44	Pro forma Adjustments December 31, 2020		120,001	OTX, Col B				
45	Budget Adjustments December 31, 2021		(285,860)	OTX, Col D				
46	Budget Adjustments December 31, 2022		2,209,933	OTX, Col F		$ 1,048,284	PF-3-S2-S	$ 1,048,284
47	Ratemaking Adjustments December 31, 2022		(3,531,961)	OTX, Col H		$ 91,623	PF-4-S2-S	$ 91,623
48	Settlement Ratemaking Adjustments December 31, 2022		954	OTX, Col J[2]				
49	Total Taxes Other Than Income	$ 31,241,852	$ (1,486,933)		$ 29,754,919	$ 1,139,907		$ 30,894,826
50	**Operating Income Before Income Taxes**	107,679,991	$ 7,859,112		115,539,103	$ 70,456,394		$ 185,995,497
51	**Income Taxes**							
52	Federal and State Taxes (Actual / Pro Forma)	$ (6,245,304)	16,254,183	Attachment 3-C-S2-S, ITX 1	$ 10,008,879	17,563,790	PF-5-S2-S	$ 27,572,669
53	Total Taxes	$ 24,996,548	14,767,250		$ 39,763,798	$ 18,703,697		$ 58,467,495
54	**Total Operating Expenses including Income Taxes**	$ 324,854,465	$ 35,413,263		$ 360,267,728	$ 18,907,678		$ 379,175,406
55	**Required Net Operating Income**	$ 113,925,295	$ (8,395,071)		$ 105,530,224	$ 52,892,604		$ 158,422,828

Footnote 1 - Unless otherwise noted
Footnote 2 - Attachment 3-B-S2-S Reference

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, 2022

Line No.	Description					Revenue Deficiency
1	Net Original Cost Rate Base					$ 2,418,669,134
2	Rate of Return					6.55%
3	Net Operating Income					158,422,828
4	Pro forma Net Operating Income					105,530,224
5	Increase in Net Operating Income (NOI Shortfall)					52,892,604
6	Effective Incremental Revenuel NOI Conversion Factor					73.666%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)					$ 71,800,281
8	One		1.000000			
9	Less: Public Utility Fee		0.001276			
10	Less: Bad Debt		0.002841			
11	State Taxable Income			0.995883		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	0.014600				
14	Taxable Adjusted Gross Income Tax		0.995883			
15	Adjusted Gross Income Tax Rate		0.049000			
16	Adjusted Gross Income Tax			0.048798		
17	Line 11 less line 13 less line 16				0.932485	
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					73.666%

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2022

Line No.	Description		Pro forma As Of December 31, 2022	Attachment 3-B-S2 Reference
	Rate Base			
1	Utility Plant	$	3,815,305,221	RB, Col I
2	Common Allocated		189,363,233	RB, Col I
	Total Utility Plant	**$**	**4,004,668,454**	RB, Col I
3	Accumulated Depreciation and Amortization	$	(1,578,834,102)	RB, Col I
4	Common Allocated		(124,923,724)	RB, Col I
	Total Accumulated Depreciation and Amortization	**$**	**(1,703,757,826)**	RB, Col I
	Net Utility Plant	**$**	**2,300,910,628**	RB, Col I
5	Cause No. 44988 Regulatory Assets	$	6,195,174	RB, Col I
6	TDSIC Regulatory Asset		11,652,922	RB, Col I
7	FMCA Regulatory Asset		14,584,863	RB, Col I
8	Materials & Supplies		13,684,877	RB, Col I
9	Gas Stored Underground - Current A/C 164 (13-mo avg)		66,691,249	RB, Col I
10	Gas Stored Underground - Non-Current A/C 117		4,949,422	RB, Col I
	Total Rate Base	**$**	**2,418,669,134**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure
As Of December 31, 2022

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 3,807,197,234	49.47%	9.85%	4.87%
2	Long-Term Debt	2,793,901,786	36.30%	4.52%	1.64%
3	Customer Deposits	64,944,910	0.84%	4.64%	0.04%
4	Deferred Income Taxes	1,436,388,185	18.66%	0.00%	0.00%
5	Post-Retirement Liability	26,333,943	0.34%	0.00%	0.00%
6	Prepaid Pension Asset	(433,959,232)	-5.64%	0.00%	0.00%
7	Post-1970 ITC	909,368	0.01%	7.59%	0.00%
8	**Totals**	**$ 7,695,716,194**	**100.00%**		**6.55%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 3,807,197,234	57.68%	9.85%	5.68%
10	Long-Term Debt	2,793,901,786	42.32%	4.52%	1.91%
11	**Totals**	**$ 6,601,099,020**	**100.00%**		**7.59%**

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 GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2022 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
	DEPRECIABLE PLANT									
	UNDERGROUND STORAGE PLANT									
350.20	LEASEHOLDS	06-2032	75-R4 *	0	385,804.99	374,165	11,640	1,229	0.32	9.5
350.40	RIGHTS OF WAY	06-2032	75-R4 *	0	191,697.23	91,710	99,987	10,574	5.52	9.5
351.10	WELL STRUCTURES	06-2032	70-R4 *	(5)	19,286.59	17,003	3,248	348	1.80	9.3
351.20	COMPRESSOR STATION STRUCTURES	06-2032	70-R4 *	(5)	412,261.17	305,653	127,221	13,449	3.26	9.5
351.30	MEASURING AND REGULATING STATION STRUCTURES	06-2032	70-R4 *	(5)	111,522.21	112,863	4,236	448	0.40	9.5
351.40	OTHER STRUCTURES	06-2032	70-R4 *	(5)	3,956,496.80	2,956,102	1,198,220	128,235	3.24	9.3
352.00	WELLS	06-2032	65-S4 *	(15)	15,567,286.30	16,336,519	1,565,860	166,076	1.07	9.4
352.30	NONRECOVERABLE NATURAL GAS	06-2032	50-SQ *	0	5,540,824.84	4,854,056	686,769	72,292	1.30	9.5
353.00	LINES	06-2032	50-S1.5 *	(25)	22,698,125.01	21,742,971	6,629,685	715,873	3.15	9.3
354.00	COMPRESSOR STATION EQUIPMENT	06-2032	50-R3 *	(10)	3,758,571.68	3,027,208	1,107,221	118,058	3.14	9.4
355.00	MEASURING AND REGULATING STATION EQUIPMENT	06-2032	60-R2.5 *	(10)	2,858,971.97	2,208,397	936,472	102,400	3.58	9.1
356.00	PURIFICATION EQUIPMENT	06-2032	65-R4 *	(5)	12,374,499.07	9,247,339	3,745,885	395,815	3.20	9.5
357.00	OTHER EQUIPMENT	06-2032	30-S2.5 *	0	1,037,788.69	984,143	53,646	6,726	0.65	8.0
	TOTAL UNDERGROUND STORAGE PLANT				**68,913,136.55**	**62,258,127**	**16,170,090**	**1,731,523**	**2.51**	
	OTHER STORAGE PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	06-2031	65-R4 *	(10)	9,347,116.00	8,636,445	1,645,383	195,063	2.09	8.4
362.10	GAS HOLDERS	06-2031	55-S3 *	(10)	18,419,738.80	19,536,495	725,218	85,329	0.46	8.5
363.00	PURIFICATION EQUIPMENT	06-2031	55-S2.5 *	(5)	1,720,662.88	1,505,828	300,868	38,342	2.23	7.8
363.10	LIQUEFACTION EQUIPMENT	06-2031	50-S2 *	(5)	8,339,875.34	7,709,263	1,047,606	125,348	1.50	8.4
363.20	VAPORIZING EQUIPMENT	06-2031	50-R2 *	(5)	5,130,282.84	5,176,829	209,968	25,146	0.49	8.3
363.30	COMPRESSOR EQUIPMENT	06-2031	40-R2 *	(5)	3,104,734.02	2,033,740	1,226,230	147,348	4.75	8.3
363.40	MEASURING AND REGULATING EQUIPMENT	06-2031	55-R1.5 *	(5)	1,619,393.44	1,248,508	451,855	54,992	3.40	8.2
363.50	OTHER EQUIPMENT	06-2031	35-R2 *	(5)	2,290,882.33	1,668,416	737,010	91,256	3.98	8.1
	TOTAL OTHER STORAGE PLANT				**49,972,685.65**	**47,515,524**	**6,344,138**	**762,824**	**1.53**	
	TRANSMISSION PLANT									
365.20	LAND RIGHTS		75-R4	0	14,820,746.32	2,697,090	12,123,657	248,409	1.68	48.8
366.20	MEASURING AND REGULATING STATION STRUCTURES		60-R3	(5)	7,575,894.52	1,347,685	6,607,005	133,703	1.76	49.4
366.30	OTHER STRUCTURES		55-R4	(5)	1,622,883.58	201,160	1,502,868	32,135	1.98	46.8
367.00	MAINS		95-R3	(30)	727,258,845.16	115,458,035	829,978,463	9,764,160	1.34	85.0
369.00	MEASURING AND REGULATING STATION EQUIPMENT		58-R2	(35)	179,999,363.97	27,806,742	215,192,399	4,128,208	2.29	52.1
371.00	OTHER EQUIPMENT		30-R2.5	0	400,722.01	46,309	354,413	13,427	3.35	26.4
	TOTAL TRANSMISSION PLANT				**931,678,455.56**	**147,557,021**	**1,065,758,805**	**14,320,042**	**1.54**	
	DISTRIBUTION PLANT									
374.20	LAND RIGHTS		75-R4	0	1,935,421.67	413,344	1,522,078	25,731	1.33	59.2
375.00	STRUCTURES AND IMPROVEMENTS		70-R4	(10)	4,781,999.49	2,128,730	3,131,470	64,017	1.34	48.9
376.10	MAINS - STEEL		85-R2.5	(40)	332,478,778.26	141,970,165	323,500,125	5,119,602	1.54	63.2
376.20	MAINS - PLASTIC		85-R2.5	(40)	853,164,755.14	266,192,416	928,238,241	12,492,652	1.46	74.3

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 GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAI		55-R1.5	(35)	58,512,779.32	22,637,588	56,354,664	1,269,232	2.17	44.4
380.10	SERVICES - STEEL[1]		68-R2	(120)	73,604,188.26	55,873,020	106,056,195	3,000,649	4.08	35.3
380.20	SERVICES - PLASTIC[1]		68-R2	(120)	750,598,791.29	465,110,728	1,186,206,613	21,391,440	2.85	55.5
381.00	METERS		36-R2	(5)	186,211,901.40	35,240,229	160,282,267	6,877,267	3.69	23.3
382.00	METER INSTALLATIONS		55-R1	(30)	197,975,095.99	136,396,495	120,971,130	2,362,395	1.19	51.2
383.00	HOUSE REGULATORS		55-R1.5	(30)	128,638,934.98	78,337,956	88,892,660	1,805,905	1.40	49.2
384.00	HOUSE REGULATOR INSTALLATIONS		55-R2.5	(10)	3,836,976.64	3,117,501	1,103,174	25,122	0.65	43.9
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMEI		60-R2	(10)	66,269,699.43	25,831,110	47,065,560	1,080,582	1.63	43.6
386.00	OTHER PROPERTY ON CUSTOMER PREMISES		15-R3	0	40,468.46	34,000	6,468	723	1.79	8.9
	TOTAL DISTRIBUTION PLANT				**2,658,049,790.33**	**1,233,283,280**	**3,023,330,645**	**55,515,317**	**2.09**	
	GENERAL PLANT									
389.20	LAND RIGHTS		65-R4	0	2,095,915.21	185,279	1,910,636	41,685	1.99	45.8
390.00	STRUCTURES AND IMPROVEMENTS									
	GAS OPERATIONS CENTER	06-2044	50-S0 *	(10)	2,969,959.68	1,285,544	1,981,412	113,701	3.83	17.4
	SOUTH BEND OPERATIONS HEADQUARTERS	06-2042	50-S0 *	(10)	5,857,657.97	2,484,059	3,959,365	249,228	4.25	15.9
	CENTRAL GAS METER SHOP	06-2029	50-S0 *	(10)	2,066,628.28	1,164,371	1,108,920	181,781	8.80	6.1
	PERU OPERATIONS HEADQUARTERS	06-2028	50-S0 *	(10)	1,400,816.35	646,971	893,927	169,012	12.07	5.3
	FORT WAYNE OPERATIONS HEADQUARTERS	06-2040	50-S0 *	(10)	6,176,475.12	2,495,298	4,298,825	360,047	5.83	11.9
	OTHER MISCELLANEOUS STRUCTURES		50-S0	(10)	7,072,709.56	1,595,437	6,184,544	161,644	2.29	38.3
	TOTAL STRUCTURES AND IMPROVEMENTS				25,544,246.96	9,671,680	18,426,993	1,235,413	4.84	
391.10	OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	1,049,130.25	585,150	463,980	52,462	5.00	8.8
391.20	COMPUTER EQUIPMENT		7-SQ	0	18,083.71	14,897	3,187	2,584	14.29	1.2
392.40	TRANSPORTATION EQUIPMENT - TRUCKS > 13,000 #		15-L4	15	229,771.29	195,305	0	0	- ***	-
393.00	STORES EQUIPMENT		30-SQ	0	149,618.01	82,055	67,563	4,987	3.33	13.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	16,753,655.56	8,291,500	8,462,156	670,196	4.00	12.6
395.00	LABORATORY EQUIPMENT		20-SQ	0	1,830,715.53	977,250	853,466	91,561	5.00	9.3
396.00	POWER OPERATED EQUIPMENT		13-L2	15	869,209.94	738,828	0	0	- ***	-
397.00	COMMUNICATION EQUIPMENT		15-SQ	0	2,132,140.37	1,077,900	1,054,240	142,148	6.67	7.4
398.00	MISCELLANEOUS EQUIPMENT		20-SQ	0	384,075.77	203,800	180,276	19,209	5.00	9.4
	TOTAL GENERAL PLANT				**51,056,562.60**	**22,023,644**	**31,422,497**	**2,260,245**	**4.43**	
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION									
391.10	OFFICE FURNITURE AND EQUIPMENT					(164,541)		54,847 **		
391.20	COMPUTER EQUIPMENT					(1,202,026)		400,675 **		
393.00	STORES EQUIPMENT					(15,264)		5,088 **		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(1,474,536)		491,512 **		
395.00	LABORATORY EQUIPMENT					(227,345)		75,782 **		
397.00	COMMUNICATION EQUIPMENT					(447,057)		149,019 **		
398.00	MISCELLANEOUS EQUIPMENT					48,296		(16,099) **		
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION					**(3,482,473)**		**1,160,824**		

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 GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	TOTAL DEPRECIABLE PLANT				3,759,670,630.69	1,509,155,124	4,143,026,175	75,750,775	2.01	
	NONDEPRECIABLE PLANT									
301.00	ORGANIZATION				7,147.20	(36,462)				
302.00	FRANCHISES AND CONSENTS				61,624.80	41,281				
303.00	INTANGIBLE PLANT				34,483,737.27	33,713,862				
350.10	LAND				85,274.96					
360.10	LAND				1,274,922.85					
365.10	LAND				11,968,764.03					
374.10	LAND				2,109,568.00					
388.00	ARO				20,706,098.41					
389.10	LAND				619,587.89					
392.10	TRANSPORTATION EQUIPMENT - AUTOS								***	
392.20	TRANSPORTATION EQUIPMENT - TRAILERS								***	
392.30	TRANSPORTATION EQUIPMENT - TRUCKS < 13,000 #								***	
	TOTAL NONDEPRECIABLE PLANT				71,316,725.41	33,718,681				
	TOTAL GAS PLANT IN SERVICE				3,830,987,356.10	1,542,873,805	4,143,026,175	75,750,775		

* INTERIM SURVIVOR CURVE USED. EACH LOCATION HAS A UNIQUE PROBABLE RETIREMENT DATE.
** 5-YEAR AMORTIZATION OF UNRECOVERED RESERVE RELATED TO IMPLEMENTATION OF AMORTIZATION ACCOUNTING.
*** ACCRUAL RATE TO BE BOOKED TO NEW ADDITIONS AS OF JANUARY 1, 2023 WILL BE:

ACCOUNT	RATE
392.10	9.95
392.20	6.30
392.30	8.88
392.40	5.86
396.00	6.80

TDSIC Allocators[1]

Class	Revenues at Current Rates	Revenue Increase	Total Revenue	Percentage of total per class which will be the TDSIC allocator
Rate 111	$525,585,924	$52,960,388	$578,546,312	65.75%
Rate 115	$4,877,756	$399,321	$5,277,077	0.60%
Rate 121 / 134	$194,557,312	$9,729,065	$204,286,377	23.21%
Rate 125	$31,776,675	$1,242,227	$33,018,902	3.75%
Rate 128 DP	$9,304,550	$3,676,622	$12,981,172	1.48%
Rate 128 HP	$36,772,091	$3,294,500	$40,066,591	4.55%
Rate 138	$5,325,132	$497,877	$5,823,009	0.66%
Total	**$808,199,440**	**$71,800,000**	**$879,999,440**	**100.00%**

1 The revenue increase shown here rounds the actual agreed revenue increase of $71,800,282. Revenue at Current Rates and Total Revenue excludes miscellaneous revenues.