[PROPOSED ORDER – FILED BY LAPORTE COUNTY]
AUGUST 27, 2019

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
August 27, 2019
INDIANA UTILITY
REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	**CAUSE NO. 45159** **APPROVED:**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Stefanie N. Krevda, Commissioner
Brad J. Pope, Administrative Law Judge

On October 31, 2018, Northern Indiana Public Service Company LLC ("NIPSCO," "Petitioner," or "Company") 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 Commission's Minimum Standard Filing Requirements and Request for Administrative Notice with the Indiana Utility Regulatory Commission ("Commission"). On October 31, 2018, Petitioner also filed its case-in-chief, workpapers, administrative notice documents and information required by the Minimum Standard Filing Requirements ("MSFRs") set forth in 170 IAC 1-5-1.

NIPSCO provided testimony and exhibits from the following witnesses:[1]

- Violet Sistovaris, President with NIPSCO[2]
- Michael Hooper, Senior Vice President of Regulatory, Legislative Affairs and Strategy

[1] NIPSCO also filed Petitioner's Confidential Exhibit No. 20-S1 and Confidential Exhibit No. 20-S2 providing support for its accounting adjustments.
[2] NIPSCO late-filed attachments to Ms. Sistovaris' testimony on February 5, 2019.

with NIPSCO[3]

- Paul S. Kelly, Vice President of Major Accounts with NIPSCO
- Jennifer L. Shikany, Director of Regulatory with NiSource Corporate Services Company ("NCSC")[4]
- Clifton Scott, State Finance Director with NIPSCO
- Patrick N. Augustine, Principal in Charles River Associates' Energy Practice
- Kelly R. Carmichael, Vice President of Environmental with NIPSCO
- Andrew S. Campbell, Director of Regulatory Support & Planning with NIPSCO
- Kimberly K. Cartella, Director of Compensation with NCSC[5]
- Victor F. Ranalletta, Associate Engineer and Project Manager of Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell")
- John J. Spanos, Senior Vice President with Gannett Fleming Valuation and Rates Consultants, LLC
- Michael D. McCuen, Director of Income Taxes with NCSC
- Vincent V. Rea, Director of Regulatory Finance and Economics with NCSC
- Paula A. Strauss, Director of Regulatory with NCSC[6]
- Bickey Rimal, Project Manager at Concentric Energy Advisors, Inc. ("Concentric")[7]
- J. Stephen Gaske, Senior Vice President of Concentric[8]
- Curt A. Westerhausen, Director of Regulatory with NCSC[9]

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[3] NIPSCO originally filed the direct testimony of Benjamin Felton. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019. NIPSCO filed corrections to Mr. Felton's direct testimony on January 2, 2019. NIPSCO filed corrections to Mr. Hooper's testimony on January 2, 2019 and April 18, 2019.

[4] NIPSCO filed corrections to Ms. Shikany's testimony on January 2, 2019.

[5] NIPSCO originally filed the direct testimony of Christopher D. Smith. NIPSCO filed corrections to Mr. Smith's testimony on April 18, 2019. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019.

[6] NIPSCO originally filed the direct testimony of Amy Efland. NIPSCO filed a Notice of Substitution of Witness on December 19, 2018.

[7] NIPSCO filed corrections to Mr. Rimal's testimony on January 22, 2019

[8] NIPSCO filed corrections to Dr. Gaske's testimony on January 22, 2019

[9] NIPSCO filed corrections to Mr. Westerhausen's testimony on January 2, 2019, January 22, 2019, June 7, 2019 and July 2, 2019.

Petitions to intervene were granted to the following parties, without objection:

- **Citizens Action Coalition of Indiana, Inc. (“CAC”)**
- **Indiana Coal Council, Inc. (“ICC”)**
- **Indiana Coalition for Affordable and Reliable Electricity (“ICARE”)**
- **Indiana Municipal Utility Group (“IMUG”)[10]**
- **Board of Commissioners of Laporte County, Indiana (“LaPorte”)**
- **Modern Forge Indiana, LLC**
- **NIPSCO Industrial Group (“Industrial Group”)[11]**
- **NLMK Indiana (“NLMK”)**
- **Northern Indiana Commuter Transportation District (“NICTD”)**
- **Peabody COALSALES, LLC (“Peabody”)**
- **Dennis Rackers (“Rackers”)**
- **Sierra Club**
- **Walmart Inc. (“Walmart”)**
- **United States Steel Corporation (“US Steel”)**
- **United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796**

By docket entry dated November 21, 2018, the Commission established a procedural schedule in this matter.[12] On February 13, 2019, the Indiana Office of Utility Consumer Counselor (“OUCC”) and Intervenors filed their respective cases-in-chief. The Commission conducted a public field hearing on March 11, 2019 at Hammond High School Auditorium. At the field hearing, members of the public were afforded an opportunity to make statements to the Commission.

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[10] The companies that comprise IMUG are Town of Highland, Town of Schererville, Town of Munster, Town of Dyer, Town of Griffith, Town of Winfield, City of East Chicago, and City of Valparaiso.

[11] The companies that comprise the Industrial Group are Accurate Castings, Inc., Arcelor Mittal USA, BP Products North America, Inc., Cargill, Inc., Enbridge Energy, Praxair, Inc., and USG Corporation.

[12] The procedural schedule was modified by Docket Entries dated January 29, 2019, April 11, 2019, April 24, 2019, May 1, 2019, May 10, 2019, and May 31, 2019.

The OUCC provided testimony and exhibits from the following witnesses:[13]

- Michael D. Eckert, Assistant Director of Electric Division
- Neha Medhekar, Utility Analyst II
- Wes R. Blakley, Senior Utility Analyst[14]
- J. Randall Woolridge, Professor of Finance, Smeal College of Business Administration, the Pennsylvania State University
- William H. Novak, President, WHN Consulting
- Peter M. Boerger, Ph.D., Senior Utility Analyst
- Glenn A. Watkins, President and Senior Economist, Technical Associates, Inc.

CAC provided testimony and exhibits from the following witnesses:

- Jonathan Wallach, Vice President, Resource Insight, Inc.
- John Howat, Senior Policy Analyst, National Consumer Law Center

ICC provided testimony and exhibits from the following witnesses:[15]

- Emily S. Medine, Principal, Energy Ventures Analysis[16]

ICC / ICARE provided testimony and exhibits from the following witness:

- Charles S. Griffey, Energy Consultant

IMUG provided testimony and exhibits from the following witness:

- Theodore Sommer, Partner, London Witte Group, LLC

Industrial Group provided testimony and exhibits from the following witnesses:

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[13] The OUCC filed testimony and exhibits of David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC and Lauren M. Aguilar, Utility Analyst with the OUCC that were not offered into evidence.

[14] The OUCC filed revisions to Mr. Blakley's testimony on April 10, 2019.

[151515] ICC also filed testimony of Bradley D. Scott, Chief Operating Office, Jiangnan Environmental Technology, Inc. that was withdrawn on March 5, 2019.

[16] ICC filed revisions to Ms. Medine's testimony on March 19, 2019.

- James R. Dauphinais, Managing Principal, Brubaker & Associates[17]
- Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates[18]
- Michael P. Gorman, Managing Principal, Brubaker & Associates[19]

NLMK provided testimony and exhibits from the following witness:

- James A. Lahtinen, Consultant[20]

Peabody provided testimony and exhibits from the following witness:

- Michael J. Nasi, Partner, Jackson Walker L.L.P.

Sierra Club provided testimony and exhibits from the following witness:

- Avi Allison, Senior Associate, Synapse Energy Economics, Inc.

Walmart provided testimony and exhibits from the following witness:

- Steve W. Chriss, Director, Energy Services[21]

US Steel provided testimony and exhibits from the following witnesses:[22]

- Brown D. Thornton, Director, NewGen Strategies and Solutions, LLC ("NewGen")
- Tony M. Georgis, Energy Practice President, NewGen[23]

On March 15, 2019, NIPSCO filed the rebuttal testimony of Violet Sistovaris, Michael Hooper, Paul S. Kelly, Jennifer L. Shikany, Clifton Scott, Patrick N. Augustine, Kelly R. Carmichael, Andrew S. Campbell, Victor F. Ranalletta, John J. Spanos, Michael D. McCuen,

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[17] Industrial Group filed revisions to Mr. Dauphinais testimony on July 24, 2019.
[18] Industrial Group filed revisions to Mr. Phillips testimony on July 24, 2019.
[19] Industrial Group filed revisions to Mr. Gorman's testimony on May 17, 2019.
[20] NLMK filed revisions to Mr. Lahtinen's testimony on May 17, 2019.
[21] Walmart originally filed the testimony of Gregory W. Tillman. Walmart filed a Notice of Substitution of Witness on June 11, 2019.
[22] US Steel originally filed testimony and exhibits of Constance T. Cannady, Executive Consultant, NewGen that was withdrawn on June 25, 2019.
[23] US Steel filed revisions to Mr. Georgis' testimony on March 7, 2019.

Vincent V. Rea, Paula A. Strauss, Bickey Rimal, J. Stephen Gaske, and Curt A. Westerhausen.[24][25][26]

Also on March 15, 2019, CAC filed cross-answering testimony of Elizabeth A. Stanton, Director and Senior Economist of the Applied Economics Clinic and a Senior Research Fellow at the Global Development and Environment Institute at Tufts University; ICC filed cross-answering testimony of Phillip Graeter, Manager at Energy Ventures Analysis; ICARE filed cross-answering testimony of Charles S. Griffey; US Steel filed cross-answering testimony of Tony M. Georgis; Sierra Club filed cross-answering testimony of Avi Allison; NLMK filed cross-answering testimony of James A. Lahtinen; and Industrial Group filed cross-answering testimony of James R. Dauphinais and Nicholas Phillips, Jr.[27]

On April 9, 2019, the Presiding Officers directed NIPSCO and the OUCC to respond to requests for information, to which NIPSCO and the OUCC responded on April 11, 2019 and April 10, 2019, respectively.

On April 26, 2019, NIPSCO, Industrial Group, NLMK Indiana, US Steel, CAC, Walmart, NICTD, Sierra Club and the OUCC (the "Settling Parties") filed a Stipulation and Settlement Agreement on Less than all the Issues resolving revenue requirements issues and other miscellaneous issues (the "Settlement"). On April 30, 2019, the Settling Parties filed a Status Update notifying the Commission that IMUG had joined the Revenue Settlement and provided an additional provision in the Revenue Settlement (Paragraph 11).[28] The Settling Parties and IMUG are collectively referred to herein as the "Revenue Settling Parties." The Settlement, as amended to include Paragraph 11, is referred to herein as the "Revenue Settlement."

On May 17, 2019 in support of the Revenue Settlement, NIPSCO filed testimony of Violet Sistovaris, Jennifer L. Shikany and Curt A. Westerhausen;[29] the OUCC filed testimony of Michael D. Eckert and Wes R. Blakley; and the Industrial Group filed testimony of Michael P. Gorman. Also on May 17, 2019, Sierra Club filed a Notice of Support for the Revenue Settlement.

On May 17, 2019, NIPSCO, Industrial Group, NLMK Indiana, and US Steel (the "Rate 831 Settling Parties") filed a Stipulation and Settlement Agreement on Rate 831 Implementation (the "Rate 831 Settlement").[30] Also on May 17, 2019, NIPSCO filed testimony of Curt A. Westerhausen; Industrial Group filed testimony of Nicholas Phillips, Jr., and US Steel filed testimony of Tony M. Georgis supporting the Rate 831 Settlement.

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24 NIPSCO filed corrections to Mr. Westerhausen's rebuttal testimony on June 7, 2019.

25 NIPSCO originally filed the rebuttal testimony of Benjamin Felton. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019. NIPSCO filed corrections to Mr. Felton's rebuttal testimony on January 2, 2019.

26 NIPSCO originally filed the rebuttal testimony of Alan Felsenthal, Managing Director at PricewaterhouseCoopers LLP that was not offered into evidence.

27 NICTD filed cross-answering testimony of Gerald R. Hanas, a consultant with GRH Commuter Rail Dynamics that was not offered into evidence.

28 IMUG filed a Formal Notice of Indiana Municipal Utility Group Joinder in Amended Partial Settlement Agreement on May 15, 2019.

29 NIPSCO filed corrections to Mr. Westerhausen's Revenue Settlement testimony on June 7, 2019.

30 The Rate 831 Settling Parties filed a revision to the Rate 831 Settlement on June 7, 2019.

On June 7, 2019, in opposition to the Revenue Settlement, ICC filed responsive testimony of Emily S. Medine; ICC and ICARE filed responsive testimony of Charles S. Griffey; and LaPorte filed responsive testimony of Reed W. Cearley.

On June 17, 2019, in opposition to the Rate 831 Settlement, OUCC filed responsive testimony of Peter M. Boerger; CAC filed responsive testimony of Kerwin L. Olson, Executive Director of CAC, and Jonathan Wallach; Walmart joined in the CAC's responsive testimony of Mr. Wallach; and Sierra Club joined in the OUCC's responsive testimony of Mr. Boerger and CAC's responsive testimony of Mr. Olson and Mr. Wallach.

On June 20, 2019, in reply to Revenue Settlement responsive testimony, NIPSCO filed reply testimony of Violet Sistovaris, Jennifer L. Shikany, Patrick N. Augustine, and Andrew S. Campbell.

On June 27, 2019, in reply to Rate 831 Settlement responsive testimony, NIPSCO filed reply testimony of Paul S. Kelly.

On July 16, 2019, the Presiding Officers directed Walmart and LaPorte to respond to requests for information, to which Walmart and LaPorte each responded, separately, on July 17, 2019.

On July 16, 2019, Rackers filed a Motion for Administrative Notice. NIPSCO filed its objection to the Motion on July 17, 2019. Rackers filed his reply to NIPSCO's objection on July 22, 2019. The Commission denied the motion by Docket Entry dated August 1, 2019.

On July 24, 2019, Rackers filed a Second Motion for Administrative Notice. NIPSCO filed its objection to the Motion on July 24, 2019. The Commission denied the motion by Docket Entry dated August 1, 2019.

Pursuant to notice given and published as required by law, the Commission conducted an evidentiary hearing in Room 222 beginning at 9:30 a.m. on July 25, 2019 and continuing through August 5, 2019. All parties presented their evidence and offered their witnesses for cross-examination.

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

1. **Notice and Jurisdiction.** Notice of the filing of the Petition in this Cause was given and published by NIPSCO as required by law. Notice was given by NIPSCO to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Notices of the public hearings in this Cause were given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1. NIPSCO is also an energy utility as defined in Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO is also a utility within the meaning of Ind. Code § 8-1-2-42.7(c). NIPSCO is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Pursuant to Ind. Code §§ 8-1-2-42 and 42.7, the Commission has jurisdiction over NIPSCO's rates and charges for utility

service. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana and provides gas and electric service ("NIPSCO Electric") in Indiana. NIPSCO is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana.

3. **Existing Rates.** NIPSCO's current electric basic rates and charges were approved in the Commission's July 18, 2016 Order in Cause No. 44688 (the "44688 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement between NIPSCO and the majority of the intervenors (the "44688 Rate Case").[31] Those new basic rates and charges went into effect on September 29, 2016. The 44688 Rate Case Order approved, among other items, an increase in NIPSCO's basic rates and charges. In addition, on May 1, 2018, NIPSCO's basic rates were modified to reflect the reduction in the federal income tax rate from 35 percent to 21 percent as approved in the Tax Cut and Jobs Act of 2017 ("TCJA") pursuant to the Commission's January 3, 2018 Order in Cause No. 45032.[32]

NIPSCO's petition initiating Cause No. 44688 was filed with the Commission on October 1, 2015. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than fifteen months have passed since the filing date of NIPSCO's most recent request for a general increase in its basic rates and charges.

4. **Relief Requested.** NIPSCO's Petition requests approval of the following:

(a) Electric Service Tariff and Standard Contract. NIPSCO seeks approval of changes to its basic rates and charges for electric utility service that will provide NIPSCO with the opportunity to earn a fair return on the fair value of its property. NIPSCO seeks approval of changes to its Electric Service Tariff, including the elimination of Riders 772 and 775, changing the series number of its rate schedules to Series 800, and miscellaneous changes to its General Rules and Regulations and Standard Contract, as proposed in its evidence to be presented in this proceeding. The overall structure of NIPSCO's tariffs remains the same for residential and commercial customers (except for a proposed increase in fixed recovery by increasing customer charges), but NIPSCO is proposing a new service structure for its industrial customers currently taking service under Rates 732, 733, and 734.

(b) NIPSCO requests that the Commission approve NIPSCO's proposal for a new industrial service structure as an alternative regulatory plan pursuant to Ind. Code § 8-1-2.5-6. To the extent any other proposals of NIPSCO herein may require alternative regulation,

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[31] The Stipulation and Settlement Agreement was entered into as of the 19th day of February, 2016, by and between NIPSCO, the OUCC, IMUG, Industrial Group, NLMK, US Steel and United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC.

[32] The Commission approved NIPSCO's 30-Day Filing No. 50167 on April 25, 2018.

NIPSCO requests that they be approved as an alternative regulatory plan. NIPSCO elects to become subject to the provisions of Ind. Code § 8-1-2.5-6 for purposes of any such proposals herein. NIPSCO requests that its proposed industrial service structure be found to be in the public interest pursuant to Ind. Code § 8-1-2.5-6.

(b) Depreciation Rates. NIPSCO seeks approval to revise its depreciation accrual rates.

(c) Previously approved Environmental Compliance Projects and Federally Mandated Compliance Projects Depreciation Rates. NIPSCO has been recognizing for ratemaking purposes the cost of previously approved qualified pollution control property, clean coal technology, and clean energy projects (collectively "Environmental Compliance Projects") and Federally Mandated Compliance Projects and associated operating expense through its ECRM and FMCA. NIPSCO proposes to reflect in its basic rates and charges the capital costs and operating expenses associated with Environmental Compliance Projects and Federally Mandated Compliance Projects previously approved by the Commission in Cause Nos. 42150, 44012, 44311, 44340, 44872 and 44889 that were or are projected to be completed and in service at the end of the forward test year (December 31, 2019) and that are currently being recovered through the ECRM and FMCA. Since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECRM. When new tariff sheets are filed based upon the final order in this proceeding, NIPSCO proposes to adjust, as applicable, its then current FMCA adjustment factors to reflect the removal of the in-service plant and related expenses as of the same effective date, and modify its allocation factors consistent with the Commission's final order, subject to any necessary variance reconciliations in the ongoing FMCA proceedings.

(d) Accounting Relief. As explained in NIPSCO's case-in-chief, NIPSCO seeks accounting authority to defer, as a regulatory asset, discounts offered to certain customers under its Economic Development Rider ("EDR") for recovery in a future rate case; authority to defer, as a regulatory liability, an amount equal to 100% of (1) annual off-system sales ("OSS") margins net of expenses and (2) back up and maintenance demand margins, both for pass back through the RTO Tracker; and authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired.

(e) DSM. NIPSCO proposes to exclude from its basic rates and charges all costs associated with its demand-side management ("DSM") program. In addition, NIPSCO has adjusted its usage determinants for energy efficiency measures installed through December 31, 2017, consistent with Evaluation, Measurement and Verification. NIPSCO has also adjusted its usage upward for energy efficiency measures installed between January 1, 2018 and December 31, 2019. NIPSCO proposes to reset lost margins in its DSM tracker filing upon new, effective base rates in this proceeding to eliminate lost margins attributable to all energy efficiency measures installed prior to December 31, 2017. Ultimately, NIPSCO is seeking a neutral transition to lost margin recovery between the filing of this rate case and the operation of its DSM tracker filing.

(f) RTO Tracker and OSS Margin Sharing. NIPSCO proposes to update Rider 771 – Adjustments of Charges for Regional Transmission Organization to (i) remove Midcontinent Independent System Operator, Inc. ("MISO") charges and credits and collect 100% of MISO charges that are not included in the FAC through the RTO; (ii) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO; (iii) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and change the allocation methodology.

(g) Environmental Cost Recovery Mechanism. NIPSCO proposes to discontinue its Rider 772 – Adjustment of Charges for Environmental Cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor (the "ECR Mechanism").

(h) Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with the Commission's orders identified in NIPSCO's case-in-chief.

(i) Prepaid Pension Asset. NIPSCO's pension plan is currently in a net prepaid pension asset position, which is the net of the related pension obligation and regulatory asset in accordance with governing accounting standards. This prepaid pension asset reduces the pension cost that would otherwise be reflected in the revenue requirement and preserves the integrity of the pension fund. NIPSCO proposes that its rates reflect this asset as part of its capital structure.

5. **Test Year and Rate Base Cutoff.** NIPSCO proposed a forward-looking test period using projected data as authorized by Ind. Code § 8-1-2-42.7(d)(1). In the docket entry setting the procedural schedule, we found that the test year for determining NIPSCO's projected operating revenues, expenses and operating income shall be the 12-month period ending December 31, 2019 (the "2019 Forward Test Year" or "Forward Test Year"). The historic base period shall be the 12-month period ending December 31, 2017 (the "2017 Historic Base Period" or "Historic Base Period"). The rate base cutoff shall reflect used and useful property at the end of the 2019 Forward Test Year.

6. **NIPSCO Case-in-Chief.**

A. Violet Sistovaris. Ms. Sistovaris provided a brief overview of NIPSCO and its role in northern Indiana. She provided an overview of NIPSCO's electric operations and customer base, and explained some of the challenges faced by NIPSCO's electric operations, such as its large industrial customer base (less than 1% of customers but over 50% of system energy sales, with the five largest customers constituting about 40% of NIPSCO's load). According to Ms. Sistovaris, this reliance on industrial sales represents a unique risk profile and makes NIPSCO's sales more susceptible to changes resulting from the business cycle. Due to the fixed nature of many costs of providing electric service, reductions in sales volumes can have a significant impact to revenues, earnings, and other customers' rates.

Ms. Sistovaris testified NIPSCO plays a critical role in northern Indiana. Safe, reliable, and affordable energy is critically important to northern Indiana. NIPSCO is continually focused on improving customer service, enhancing the availability and reliability of electricity and natural gas, and providing an infrastructure to support new jobs and economic growth. NIPSCO remains sensitive to its customers in need, as demonstrated by NIPSCO's low income program and its work with trustee offices throughout its service territory. Ultimately, NIPSCO's goal and its vision is to be the premier utility in Indiana, and it is part of our mission to engage its customers, employees and community partners to continuously improve and achieve this goal. NIPSCO's leadership team and other employees serve critical roles in various community organizations. Since its inception, NIPSCO's Charity of Choice effort has provided more than $1 million in funds to a variety of community organizations, and its Luminary Awards have shone a spotlight on community leaders to promote the importance of leadership in the continued economic viability of northern Indiana.

Ms. Sistovaris provided an overview of NiSource (NIPSCO's parent company) and its aspiration to become the premier regulated energy company in North America with top-tier safety, customer service and reliability metrics, a solid foundation of engaged, aligned and safe employees, a strong financial profile, a wide range of investment-driven growth opportunities, and robust and sustainable earnings and cash flow. She described the NiSource corporate structure and described the three core objectives of the NiSource strategic vision of investment in needed infrastructure programs, strengthening the financial foundation for access to capital to continue making ongoing investments in service quality, environmental and reliability, and enhancement of processes, performance, safety and reliability across the operating companies to provide improved customer service.

Ms. Sistovaris testified much of the infrastructure operated by the NiSource operating companies has been in service for many decades, and significant ongoing investment is required to maintain the systems in order to reliably meet current and long-term customer needs. For NIPSCO's electric service, this includes ongoing investments in Environmental Compliance Projects and investments in transmission and distribution assets. Ongoing investments in NIPSCO's electric distribution system is required as a result of: (1) new delivery infrastructure to serve new customers; (2) public improvements; (3) capacity enhancements; and (4) infrastructure replacements. Targeted transmission investment by NIPSCO individually and through its participation in MISO will continue. NIPSCO continues to balance the need for new investments with the cost to its customers. She stated that NIPSCO invested approximately $360 million in jurisdictional electric infrastructure through the 2017 Historic Base Period, and projects an additional investment of $520 million by the close of the 2019 Forward Test Year.

Ms. Sistovaris discussed significant changes to NIPSCO's generation fleet expected as a result of its 2018 Integrated Resource Plan ("2018 IRP"). She stated that on September 19, 2018, in a public meeting with interested stakeholders, NIPSCO announced the preliminary results of its 2018 IRP. The retirement analysis under the IRP currently indicates that NIPSCO will retire Units 17 and 18 at R.M. Schahfer Generating Station ("Schahfer") in 2023, as was indicated in the 2016 IRP. However, this updated retirement analysis also indicates that Units 14 and 15 at Schahfer may retire as early as 2023 and that Unit 12 at Michigan City Generating Station ("Michigan City") may also retire as soon as 2028. The earlier retirement of Units 12, 14, and 15 were driven mainly by economics in the wholesale markets.

Ms. Sistovaris stated that constantly monitoring service and reliability metrics and providing top-tier service will continue to be a priority for NIPSCO. She explained that NIPSCO is working every day to improve its customer service delivery and its public and employee safety performance. NIPSCO's commitment to continuous improvement begins with its customers and NIPSCO is driven to better understand and adapt to customer preferences. By improving processes, developing employee training and using new technologies, NIPSCO has increased the speed with which new customers are connected. Finally, building a strong leadership team at NIPSCO with deep bench strength is critical to having an engaged, diverse and safe employee team. Employee and leader development remain key strategic areas.

Ms. Sistovaris explained the importance to NIPSCO of NiSource maintaining its investment grade credit rating, including adequate liquidity and access to capital on reasonable terms to support ongoing investments in service quality, safety compliance and reliability and to manage the customer rate impact of those investments. She explained how the regulatory process impacts NiSource's corporate credit rating noting that credit rating agencies closely follow and assess regulatory proceedings and their impact on a company's financial condition.

Ms. Sistovaris stated that to realize its aspiration to become the premier regulated energy company in North America, NIPSCO needs to successfully execute a long-term, investment-driven plan to modernize its core assets and processes, and its service quality and reliability must be consistent with that provided by America's premier utilities. NIPSCO also recognizes that ongoing investments in areas beyond hard assets are necessary if NIPSCO is to become a premier company in the industry. Key among these are investments in its employees and the core processes that support them, so as to ensure a safe, engaged and effective workforce. In meeting these goals, NIPSCO must balance the need for investments with the impact on the cost to its customers. In sum, if NIPSCO is to achieve its objectives of safely providing its customers with top-tier reliability and service quality cost effectively and maintaining a solid, financial position, it is necessary to commit to balanced and consistent investments in all of these areas over the long term. She stated that NIPSCO's commitment has resulted in positive impacts for the system and for the overall experience of NIPSCO's customers.

Ms. Sistovaris testified NIPSCO's goal is to be the premier utility in Indiana in every aspect of its performance, including interaction with its customers. NIPSCO evaluates its performance with customers using multiple metrics. NIPSCO collects direct input and feedback from its customers through a range of methods, which is broadly referred to internally as its "Voice of Customer" process. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, MSR Group Surveys, NIPSCO's Community Advisory Panels, NiSource's My Energy Insights On-line Customer Panels, comments and complaints that are emailed or called into NIPSCO's Call Center, as well as the Commission's consumer affairs division. NIPSCO is also a member of several industry associations and researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the industry.

Ms. Sistovaris testified that NIPSCO's focus on its customers has resulted in the fewest customer complaints per 1,000 customers at the Commission, and NIPSCO leads major utilities with the fewest justified complaints. She stated that in 2017, NIPSCO's customer care representatives handled 1,376,378 calls. NIPSCO's Average Speed of Answer (ASA) was 28 seconds and its Abandon Rate was only 2.3%. In 2017, NIPSCO's First Call Resolution rate was 87%. In 2017, the Customer Satisfaction with CSR rate was 88%. These metrics have improved significantly since NIPSCO's last rate case.

Ms. Sistovaris described NIPSCO's customer service facilities and explained steps NIPSCO has taken to help customers save energy and reduce their monthly bills. From senior leadership to front line employees, NIPSCO has continued to elevate its internal emphasis on energy efficiency including enhanced communication with the statewide stakeholders, including governmental agencies, other utilities and consumer parties. NIPSCO has dedicated staff to energy efficiency measures, and manages the development and implementation of such measures to the benefit of its electric and gas customers. NIPSCO's electric energy efficiency programs have helped customers save more than 1 million megawatt hours from 2010 through June 30, 2018. NIPSCO offers a variety of programs for all customer segments (residential, commercial and industrial) and looks to help customers manage current energy costs and to assist NIPSCO in reducing or deferring future generation needs. NIPSCO's energy efficiency plan for 2019-2021 provide a robust portfolio of cost effective programs. In addition, NIPSCO has specifically tailored programs to assist low income customers and smaller commercial entities.

Ms. Sistovaris testified NIPSCO offers a low income energy efficiency weatherization program to both NIPSCO gas and electric customers and proposed a low income appliance replacement program in its electric energy efficiency proceeding. NIPSCO also offers a deposit program that provides a reduction in the total deposit amount for qualified low-income customers. She stated that NIPSCO is committing to establish a low income collaborative with interested stakeholders. NIPSCO believes it is imperative to work with stakeholders in order to establish low income assistance and weatherization programs that meet the needs of low income customers.

Ms. Sistovaris testified that NIPSCO is filing this case to (i) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure (ii) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (iii) revise its depreciation rates to reflect the most recent information regarding planned retirements of its generating units; and (iv) align its rates and charges required to maintain safe and reliable service. NIPSCO's proposals in this proceeding were made after initial discussion with various stakeholder groups.

Ms. Sistovaris testified NIPSCO is in the process of evolving from being highly reliant on coal-fired generation to facing the prospect of the retirement of those resources in the near term. Despite currently strong economic conditions, NIPSCO electric operations continue to face declining industrial usage driven by the development of customer-owned generation and uncertainty in some industrial markets based on international trade conditions. In addition, the industry is in the midst of a transformation toward increased reliance on gas-fired and renewable generation that is reflected in the MISO markets.

Ms. Sistovaris testified that regulatory restrictions and/or environmental costs will increase NIPSCO's cost of producing energy, which will impact generation mix, customer demand and NIPSCO's profitability. Compliance costs associated with these requirements could also affect NIPSCO's cash flow. While implementation of the Clean Power Plan was stayed by the U.S. Supreme Court, earlier this year the U.S. Environmental Protection Agency ("EPA") initiated a rulemaking to promulgate replacement requirements. The cost impact of any new or amended regulations will depend upon the specific requirements enacted, but compliance with those requirements will likely be costly to NIPSCO and its customers. NIPSCO also is addressing compliance with regulations that address the handling and disposal of coal combustion residuals ("CCRs") and may also need to address more stringent effluent limitation guidelines ("ELG") in the foreseeable future.

Ms. Sistovaris testified that major environmental controls installed since NIPSCO's last rate case include, but is not limited to: (1) installation of ground water monitoring facilities at Bailly Generating Station ("Bailly"), Michigan City, and Schahfer; (2) installation of both remote ash conveying facilities and material management areas at Michigan City and Schahfer, (3) and closure of the landfill pond at Schahfer in response to address the disposal and handling of CCRs. NIPSCO is also engaged in the installation of selective catalytic reduction ("SCR") Catalyst Layers to comply with NIPSCO's NOx Compliance Plan at Units 7, 12 and 14. The ground water monitoring facilities were placed in service prior to the close of the 2017 Historic Base Period, and the remaining investments are expected to be in service prior to the close of the 2019 Forward Test Year.

In addition to her testimony, Ms. Sistovaris sponsored: (1) Attachment 1-B, a copy of NIPSCO's notice of its intent to file an electric rate case in accordance with the Commission's General Administrative Order 2013-5; (2) Attachment 1-C, a copy of each of the Publishers' Affidavits associated with the notices published in accordance with law and Commission practice; and (3) Attachment 1-D, a copy of the written notice that was provided to residential customers within 45 days of the filing of NIPSCO's petition in this Cause.

B. Michael Hooper. Mr. Hooper testified that the filing of this case satisfies the requirement in Ind. Code § 8-1-39-9(d) that NIPSCO file an electric rate case "before the expiration of the public utility's approved seven (7) year plan."

Mr. Hooper testified there were a few drivers causing NIPSCO to request a change in rates at this time. First, is to align depreciation rates for its coal fired generating assets more closely to the expected useful life of those assets as projected in NIPSCO's 2018 IRP. Second, NIPSCO needed to address the impact of the TCJA. Third, NIPSCO is proposing a change in its large industrial service structure to address the changing economic landscape. He noted that the changes in industrial service structure is a natural evolution from the interruptible service offering that was initiated in NIPSCO's 2010 electric rate case (Cause No. 43969) and expanded in its 2015 electric rate case (Cause No. 44688). The interruptible credits and attendant registration of approximately 530 MWs of Load Modifying Resources ("LMR") at MISO facilitated the retirement of Bailly Units 7 and 8, the cost savings from which are included in this filing.

Mr. Hooper testified NIPSCO's overall revenue increase requested in this proceeding is approximately $21.4 million, or 1.4% above the revenue requirement of NIPSCO's 2015 rate case plus the inclusion of trackers that NIPSCO customers will be paying by the time the Step 2 rates in this proceeding are implemented. He stated that this is a policy case dealing with the changing energy marketplace. Mr. Hooper explained that since 2010, NIPSCO has been allowing its industrial customers to assume more market risk in exchange for supporting less of NIPSCO's production costs. He stated the new industrial service structure proposed here is the next step in this evolutionary process. He explained that in exchange for taking a set amount of contract demand for a period of five years, NIPSCO's largest, most sophisticated customers will be allowed to make more decisions regarding their energy procurement. Transitioning much of NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment resulting in a near term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward. Mr. Hooper had no doubt that if the economics continue, and NIPSCO does not respond, there is a high probability that more industrial load will leave the system, and once gone, the chances that it will return, at least in the near-term, are low. He stated that NIPSCO's generation needs will change over time, and its remaining firm customers will receive the benefits of those changes.

Mr. Hooper testified that NIPSCO's coal-fired generating units have seen a decrease in utilization in the economically optimized MISO market. He stated that with current natural gas prices, NIPSCO's coal-fired generating units that have historically been used to serve base-load find themselves being the marginal units. He stated that ramping up and down aging coal units causes increased maintenance costs as the units were not designed to operate in that manner. In addition, the recent responses to NIPSCO's Request for Proposals for generation provided more cost effective resources available to serve NIPSCO's load.

Mr. Hooper testified that with the Preferred Plan in NIPSCO's 2018 IRP, NIPSCO is proposing to retire all Schahfer coal fired generating units by December 31, 2023, and its Michigan City Unit 12 by December 31, 2028. He stated that while the alternative depreciation study conducted by Mr. Spanos also uses these retirement dates, for purposes of calculating the economic benefit of NIPSCO's alternative plans, NIPSCO used a 2030 retirement date for all coal-fired units and assumed recovery of and on those assets over that period of time. The depreciation rates, which NIPSCO proposes to implement in this proceeding are based upon a December 31, 2030 date.

Mr. Hooper testified that due to the magnitude of the effect of the change in retirement dates for NIPSCO's remaining coal-fired generating stations, NIPSCO is proposing to mitigate the effects of a significant rate increase by recovering all remaining future accruals by the end of 2030, as opposed to the physical retirement date of the units. He stated that because the recovery of depreciation expense extends beyond the anticipated physical retirement date of the asset, when NIPSCO retires the coal fired generation units at Schahfer by 2023 there will be a significant amount of remaining net book value. Mr. Hooper stated NIPSCO proposes to treat these retirements as extraordinary retirements. At the retirement date, NIPSCO would create a regulatory asset equal to the remaining net book value of the Schahfer coal fired generating units. He testified that NIPSCO proposes that this regulatory asset be included in rate base and be amortized through December 31, 2030 in an amount equal to the annualized monthly level of depreciation expense based on the month preceding the retirement. He noted that NIPSCO's 2018 IRP analysis included the recovery of and on these assets through 2030.

Mr. Hooper explained that this treatment is appropriate from a policy perspective. First, it mitigates the amount of rate increase necessary in this case by delaying NIPSCO's recovery of its return of and on its investments in coal-fired generation assets. Second, it assures that over time, NIPSCO will receive the return of and on its generating assets that have served its customers well over the last few decades. Finally, it fairly balances the interests of NIPSCO's stakeholders. He stated that while shifting recovery past the end of the useful life causes a mismatch between those customers receiving value versus those paying for assets, NIPSCO's position is that 2030 is not so far into the future that too large a distortion will take place. He pointed out that the longer the recovery period, the greater the mismatch.

Mr. Hooper testified NIPSCO did not include in the proposed depreciation accrual rates any of the costs related to certain asset retirement obligations that must be performed in compliance with the CCRs rule (referred to herein as the "Asset Retirement Obligations"). He explained that the federal regulations underlying the Asset Retirement Obligations have recently been revised, and the full impact of the regulations is not yet certain. He testified that NIPSCO intends to seek recovery of these costs in a future base rate proceeding or through its FMCA mechanism when NIPSCO is more confident in the effects of the regulations and its costs become better estimated.

Mr. Hooper testified NIPSCO is proposing to return both protected and unprotected excess ADIT over the remaining life of the assets. He stated the treatment of protected excess ADIT is required by the Internal Revenue Service ("IRS") and the proposed treatment of the unprotected excess ADIT makes sense from a policy perspective as those continuing to pay for the assets will receive the offsetting credit for the return of the excess ADIT. He noted that shortening of the depreciation lives of NIPSCO's coal-fired generation assets increases the speed at which excess ADIT is returned to NIPSCO's customers.

Mr. Hooper explained NIPSCO's Customer Value Initiative. He stated that NiSource and NIPSCO deliver Customer Value in a balanced way across four key dimensions: safety, customer experience, a great place to work, and affordability. He stated that focus on that balance will help ensure the long-term sustainability of our business, driving planning, performance management and accountability from the perspective of industry-leading customer value. He explained that NIPSCO has made progress in recent years on key metrics in safety, reliability and customer service. He stated NIPSCO has demonstrated commitment to, and execution of, its long-term infrastructure replacement plan. He stated that effective July 1, 2015, NiSource separated from its natural gas pipeline, midstream and storage company (Columbia Pipeline Group). Post-separation, NiSource maintains significant scale and remains one of the largest natural gas and electric utility companies in the United States. Nevertheless, various corporate structures and processes were modified to appropriately serve the new entity. He stated that in 2017, a NiSource initiative focusing on long term affordability was identified and was launched in 2018 to ensure that every dollar of revenue delivers the maximum value possible for customers. He stated that potential opportunities to achieve these goals will be identified through a comprehensive review of how work is done at all levels of the Company. He testified NIPSCO will ensure that it is being as efficient and effective as possible with its resources by creating stronger processes, improving role clarity and providing reliable, quality services as quickly as possible. He explained that the Transformation Organization, at NCSC, is guiding and overseeing the implementation of the initiative. Continuous improvement teams, called Business Customer Value Teams, and processes were created for the Operations, Capital and Corporate functions and will assess the respective organizations and work streams. He stated that a wave approach has been employed for project identification and implementation, with the first wave beginning in March 2018. Ultimately, establishing a culture of continuous improvement will ensure ongoing resource maximization and sustainability.

Mr. Hooper described NIPSCO's derivation of its proposed revenue allocation. He stated that NIPSCO began with a fully allocated cost of service study and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MWs of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement from this case overall customer classes equally, resulting in a rate increase for all other customer classes of 11.76%. He stated that NIPSCO proposed the methodology to avoid rate shock to its Residential customers. He testified that if not for the mitigation, the rate increase would be approximately 32.2% for Residential customers.

Mr. Hooper provided an overview of NIPSCO's proposed rate design. He stated that NIPSCO had three overall policy objectives in the development of the rates proposed in this proceeding: (1) restructure the industrial rate classes to accommodate the large industrial customers that want to reduce their dependence on NIPSCO generation; (2) moderate rate shock for the other rate classes; and (3) ensure that rate design calculations are simple and transparent. With regard to its Residential customer charge, he testified NIPSCO proposes to take a relatively small step towards further fixed-variable alignment. Specifically, NIPSCO proposes to increase the customer charge that applies to residential and small commercial customers in a manner that simply improves recovery of the fixed costs to serve the customer and billing functions for customers. He testified the proposed residential customer charge of $17 per month would improve that alignment. He explained that based upon a full allocation of costs in the allocated cost of service study, the customer costs alone support a charge of $21.47 and including the full fixed cost of the transmission and distribution system would support $49.76. He stated that those costs above $17 are still recovered through a variable charge, or the energy charge. However, noting that the currently-effective monthly customer charge is $14, in the spirit of gradualism, a $17 per customer per month is an appropriate step through this rate case.

Mr. Hooper testified NIPSCO is proposing to increase its revenues by $21.4 million. He stated that a return equivalent to the weighted average cost of capital ("WACC") as applied to the net book value of NIPSCO Electric's assets reflects a fair return on the fair value of NIPSCO's used and useful property. This represents an overall increase of 1.4%, to be allocated among NIPSCO's customers according to the rate design and cost of service study sponsored by Dr. Gaske and incorporated into the proposed tariffs sponsored by Mr. Westerhausen. He testified that NIPSCO collaborated with its stakeholders prior to making its filing by reaching out, sharing information, and soliciting their input on key issues. He stated the Company met numerous times with the representatives of the settling parties to its last electric rate case filing over the past few months to educate them on this filing and the issues driving it, as well as to listen to any suggestions or concerns they might have. Mr. Hooper testified NIPSCO seeks to promote simplicity, transparency, and collaboration with its stakeholders, respond to customers' needs, and reach a balanced set of proposals that is fair and reasonable.

C. <u>Paul S. Kelly</u>. Mr. Kelly testified the changing economic landscape includes the inefficiencies attributable to coal-fired generation and the availability of more economic alternatives within the MISO market for NIPSCO's customers. He stated that NIPSCO's large industrial customers utilize energy intensive processes and are sophisticated market participants, who participate in energy markets globally, and compete on the basis of price globally. NIPSCO believes that right now is the time to address the needs of its large industrial customers for a market sensitive rate structure at the same time it addresses its on-going generation needs. He stated that in NIPSCO's 2018 IRP, analyses were performed for each of NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. NIPSCO used a number of factors in analyzing the retirement timing of the coal units including economics, cost risk, reliability risk and impacts to NIPSCO's employees, and the local economy. He testified that

NIPSCO's filing in this case requires its largest industrial customers to remain as NIPSCO's retail customers, while at the same time providing more market choices and is also synchronized with the preferred plan presented in NIPSCO's 2018 IRP. Mr. Kelly noted that an example of the changing landscape and resulting economics in the energy market is the March 29, 2018, Whiting Clean Energy, Inc. ("WCE") and BP Products North America ("BP") joint petition at the Commission docketed as Cause No. 45071, seeking treatment of WCE as a Qualified Facility ("QF") able to provide energy directly to BP.

Mr. Kelly provided the estimated annual margin losses for losses from aggregation of the WCE and BP Refinery based on the existing Rate 733 tariff, and testified that it is both possible and probable for other industrial customers to also reduce their firm loads. He stated that some large customers, like BP, may utilize co-generation systems whether new or existing to reduce their firm requirements. In fact, NIPSCO is already aware that other large industrial customers are considering expansion of their cogeneration facilities. Others may reduce those loads by shifting their industrial production to other locations outside Indiana that are more economic to operate. Mr. Kelly testified that because large industrial sales constitute such a significant portion of NIPSCO's retail electric sales, NIPSCO would experience decreased revenues and operating margins far faster than could be offset by growth in other sectors. He stated that in the long run, such load loss would subject remaining customers and customer classes to increased costs.

Mr. Kelly testified that after months of discussion with its largest industrial customers, NIPSCO is proposing a new Rate 831 market sensitive industrial service structure. He stated that over the years, NIPSCO has allowed its largest customers to incur more market risk in exchange for supporting less of NIPSCO's production costs. In Cause No. 43969, NIPSCO expanded its long-standing use of interruptible service to be of use in the evolving MISO market. In Cause No. 43969, NIPSCO transitioned from special contract-based interruptible service offerings to tariff Rider 675. Seven customer historically interruptible premises took service subject to that new Rider, and NIPSCO's capacity requirements in the MISO market were reduced by approximately 377 MWs. In Cause No. 44688, NIPSCO expanded the availability of the interruptible rate at the request of its industrial customers, and its interruptible customers allowed NIPSCO to reduce its capacity requirements by approximately 530 MWs, which ultimately led to the earlier closure of Bailly Units 7 and 8. He stated that this interruptible/curtailable design, the reductions in NIPSCO's industrial load, and the current electric generation economic landscape, lead NIPSCO and its industrial customers to believe that the time has come to allow further access into the energy marketplace while retaining NIPSCO's provision of retail service and providing protections for its remaining firm customers.

Mr. Kelly testified Rate 831 will replace Rates 732, 733, and 734 and Rider 775 for NIPSCO's largest industrial customers. He stated the availability requirements for Rate 831 are: (1) any transmission or sub-transmission voltage-connected customer with a load of at least 10 MWs, (2) interval data recorder ("IDR") metering, and (3) a five year contract. He explained that three tiers of service are offered under the rate, and the customer will be given the opportunity to be served under Tier 1 with either, or both, of the other two, Tiers 2 and 3. Mr. Kelly described the three tiers as follows:

Tier 1

Under Rate 831, a customer is required to take a minimum of 10 MWs of Tier 1 firm service. The Tier 1 rates were designed based on approximately 184 MWs (measured at the meter) being subscribed from NIPSCO's five largest industrial customers (approximately 190 MW measured at the generator bus bar). Tier 1 is billed as a fixed demand charge for production and customer related charges and is considered first through the meter for purposes of energy except when the customer is taking back up or maintenance services defined in the tariff. Tier 1 is also subject to all applicable Riders as listed on Appendix A of the tariff filed in this proceeding. Tier 1 will be billed as first through the meter up to the applicable amount of Tier 1 contract demand. A customer is required to provide five years of notice to increase the Tier 1 contract demand and must execute a new five year contract for the increased service.

Tier 2

Tier 2 is a non-firm curtailable service. NIPSCO will register as a Load Modifying Resource ("LMR") at MISO that portion of a customer's Tier 2 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party. Under Tier 2, the customer will take all Energy at the MISO Day-Ahead LMP at the applicable Company Load Zone. Tier 2 is subject only to the non-production Riders applicable to non-firm service (currently the energy portion of NIPSCO's RTO tracker, and any NERC/CIP components of NIPSCO's FMCA tracker). Tier 2 will be billed as second through the meter up to the amount of Tier 2 contract demand after calculating the amount of Tier 1 energy.

Tier 3

Tier 3 is also a non-firm curtailable service. NIPSCO will register as a LMR at MISO that portion of a customer's Tier 3 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party, but NIPSCO will only register a single LMR for any non-firm load if a customer chooses to take both Tier 2 and 3 service. NIPSCO, as the MISO Market Participant, will register participating customers as an Asset Owner at MISO, which will allow the customer access to the MISO Market Portal to carry out MISO Asset Owner functions. Tier 3 is subject to any NERC/CIP components of NIPSCO's FMCA tracker but not the components of the RTO Tracker that Tier 2 will be responsible for given that Tier 3 customers will be invoiced for those charges directly from MISO as an Asset Owner. If, under the MISO Asset Owner framework, a customer has not arranged for any third party energy with NIPSCO as the contracting Market Participant, the customer will take all energy under this Tier 3 service at the market price (LMP at the applicable Company Load Zone plus all applicable MISO charges / transmission charges). All settlements associated with the customer's Asset Owner energy offers and demand bids will be passed through to the Tier 3 customer. All three tiers will pay volumetric transmission charges for all energy delivered to their premises with a discount available for adjacent customer-owned premises that contain co-generation facilities capable of outputting energy to NIPSCO's system. Tier 3 will be billed as last through the meter.

Mr. Kelly testified that under the proposed rate, if multiple premises are held under common ownership and at the same qualifying service voltage, NIPSCO will allow customers to aggregate those loads with IDR metering as a single service. He stated that each IDR meter qualifying for aggregation under the rate will be included in the customer's contract to avoid confusion on which meters will or will not be included within the aggregation calculations. Mr. Kelly testified that NIPSCO is requiring a five year contract to balance the needs of all stakeholders in launching the proposed service structure. He stated that NIPSCO and its other customers need these Rate 831 customers to continue to contribute to the fixed costs of production long enough to achieve an orderly transition to NIPSCO's preferred plan in the 2018 IRP. He stated that without a five year contract, these customers could have an incentive to reduce their contract demands to a level that would immediately require NIPSCO to file another rate case to reallocate the under collected revenue to remaining classes. Also, without the five year notice provision to increase the firm Tier 1 contract demand, NIPSCO could be forced to procure uneconomic capacity to meet the increased need due to the inability to properly evaluate and potentially construct required capacity resources. He stated this is especially problematic given the lead times to navigate the MISO interconnection queue and construct various generation technologies all of which also have long useful lives. Considering these issues, he stated the five-year contract period provides a reasonable level of certainty for NIPSCO and all of its customers in moving to a structure that provides more market choices for the Rate 831 customers in exchange for that commitment.

Mr. Kelly testified NIPSCO is offering an alternative transmission charge solely to customers that are held under common ownership or affiliates (as defined in Ind. Code § 23-1-43-1), which are located on adjacent premises which have cogeneration facilities that can produce power at one premise and transfer that power across NIPSCO's transmission system to an adjacent premise owned by the customer or its affiliate. He stated that because such customers will need to use only a small portion of the NIPSCO transmission system to transmit power from one of its premises to an adjacent industrial premise, NIPSCO is proposing to provide a 70 percent discount on the transmission charge for power that is transmitted between the two adjacent, affiliated premises. He stated that while discounted, the rate will result in some transmission revenue from these customers that would not occur if they built their own lines between their premises.

Mr. Kelly testified NIPSCO currently has 15 customers (23 premises) taking service under Rates 732, 733, and 734, and only five customers (9 premises) have also taken service under Rider 775. Of those 15 customers, 4 have less than 10 MWs of demand at a single premise. He stated that NIPSCO expects all five of its largest industrial customers (14 premises) to take service under Rate 831 with the remaining 10 customers expected to take service under NIPSCO's new Rate 830 including the 4 below 10 MWs which will be grandfathered onto the rate.

Mr. Kelly testified that transitioning NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment. He stated it will result in a near term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward.

Mr. Kelly described what happens if the five large industrial customers take more or less than the 184 MWs used to allocate production costs. He stated that NIPSCO is proposing a two-phase rate design approach with the following characteristics to mitigate that risk if necessary:

> **Phase 1 Filed Rates:** the as-filed rates for Rate 831 were designed with the allocated cost of service study allocating 184.556 MWs (measured at the customer meter) of NIPSCO's fixed production cost to Rate 831's Tier 1 service for the 5 largest industrial customers (or 189.794 MWs measured at the generator bus bar). This level of firm demand was based upon numerous conversations with NIPSCO's five largest customers. NIPSCO is proposing that customers will choose Tier 1, 2 and 3 contract levels within 30 days following the final order from the Commission in this rate

proceeding. NIPSCO will also adjust the RTO Tracker allocations based upon the customer's choices regarding Tiers 1, 2 and 3. Any revenue shortfall resulting from an unsubscribed portion of the 184.556 MWs will require a second phase true up.

Phase 2 Rates True-Up: If, after the final order, the total amount of Tier 1 firm service chosen by the five largest industrial customers is different than 184.556 MWs, final rates will be set in the Phase 2 rates to collect the appropriate revenue. NIPSCO will also adjust the RTO Tracker allocations based upon the customer's choices regarding Tiers 1, 2 and 3.

Mr. Kelly briefly described NIPSCO's new Rate 830. He stated that recognizing that not all of NIPSCO's largest industrial customers would be interested in the market sensitive service under Rate 831, NIPSCO has designed Rate 830 to provide an industrial service that is very similar to the current Rate 732, with a few exceptions. He testified that between Rate 830 and 831, NIPSCO's largest industrial service customers will be able to select a service option that meets their needs for firm service and their tolerance for different levels of market risk.

Mr. Kelly testified NIPSCO's proposed new industrial service structure is in the public interest as required for an alternative regulatory plan as set out in Ind. Code ch. 8-1-2.5. He stated that Rate 831 will only be offered to energy intensive, highly sophisticated customers that compete directly or indirectly in a global market. He stated that traditional retail service at fixed rates as determined by the Commission is no longer necessary for the large industrials loads capable of being served through curtailable services with products from the FERC regulated MISO capacity and energy marketplace. He stated that the Commission's approval of this innovative service structure is beneficial to NIPSCO's industrial customers, its remaining firm customers and to NIPSCO. He stated that NIPSCO is currently implementing the preferred plan from its 2018 IRP for best serving our customers with generation capacity. He explained that to the extent that its future generating needs can be reduced, all customers will benefit. Mr. Kelly stated that approval of this new service structure will provide more accurate price signals, in that the customers will be paying the market rate for energy, and will be economically incented to adjust their consumption based on the market price signal.

Mr. Kelly testified NIPSCO's proposed service structure is critical for retaining the level of industrial production from NIPSCO's largest customers. He stated it is crucial for NIPSCO's other 468,000+ customers that these Rate 831 customers continue to make a contribution to NIPSCO's fixed production costs through their retail electric utility service. He stated that NIPSCO has directly observed the loss of load when customers relocate production out of northern Indiana to other facilities that they own across the US and the world. NIPSCO has also experienced the near total loss of major industrial customers due to the inability of the customer to maintain economic viability. He stated that if a major employer closes its doors or even reduces the number of operating shifts in our service territory, it will negatively impact the broader economic stability of the region as well as hinder NIPSCO's ability to provide reasonably adequate service at just and reasonable rates. Mr. Kelly stated that those job losses can create a ripple effect that eventually impacts local governments and commercial businesses. In short, Mr. Kelly testified this proposed structure will best position these large industrial customers to remain cost competitive within their global markets while also contributing to NIPSCO's fixed production costs to serve. He stated that with those customers remaining and potentially expanding their industrial production in the region, this service structure could also mean the difference between a growing local economy in northern Indiana or one that is losing jobs and seeing reductions in its skilled labor force and property tax base.

Mr. Kelly testified that NIPSCO is unique in that its large industrial customers have historically accounted for more than fifty percent of its energy sales. As those customers compete globally, they are demanding electric rates that more accurately reflect the marginal cost of energy production. He testified that as NIPSCO considers retirement of its coal-fired generation and its replacement alternatives, it presents a unique opportunity to address NIPSCO's industrial customers' needs, while offering protection to its remaining customers that they will not be responsible for replacement generation cost to serve industrial load that is more volatile, and more able to leave the system with stranded cost. Mr. Kelly testified NIPSCO's proposed industrial service structure balances the interests of all stakeholders and positions NIPSCO to provide safe and reliable service at just and reasonable rates.

D. Jennifer L. Shikany. Ms. Shikany presented the results of NIPSCO's electric operations for the Historic Base Period and the projected results for the Forward Test Year adjusted on a pro forma basis for the normalization and annualization of certain amounts included in these periods. Ms. Shikany quantified the amount by which retail electric revenues should be increased so that the Company may have the opportunity to earn a fair and reasonable return.

Ms. Shikany testified NIPSCO's proposed rates are based on a forward looking test year beginning January 1, 2019 and ending December 31, 2019, consistent with Ind. Code § 8-1-2-42.7. She stated the Company has provided information for the Historic Base Period, as well as for the period beginning January 1, 2018 and ending December 31, 2018 (the "2018 Budget Period"), for comparison purposes. She stated the Company has proposed both ratemaking and forward looking adjustments to the Historic Base Period and Forward Test Year to support the forecasted amounts for the Forward Test Year as well as the normalization and annualization of these test periods. She stated NIPSCO elected to proceed under the Commission's final rules on the MSFRs (170 IAC 1-5-1 through 16) and followed Appendix B to the Commission's Recommended Best Practices for Rate Cases Submitted under Ind. Code § 8-1-2-42.7 (GAO 2013-5) as it relates to the MSFRs and the supporting documentation for changes between the Historic Base Period and the Forward Test Year.

Ms. Shikany testified that the Company proposes retail electric rates designed to recover through base rates the gross retail electric revenue in the amount of $1,545,815,189, an increase of $21,371,413 over the forecasted test year pro forma results based on current rates. She also noted that rates based upon this level of annual revenue requirements will provide NIPSCO with an opportunity to earn annual jurisdictional net operating income ("NOI") of $288,763,895. She stated NIPSCO's proposed rates have been calculated using NIPSCO's requested return on the Forward Test Year original cost rate base and capital structure. She stated NIPSCO is proposing to implement the requested rate relief in this proceeding in a two-step process to reasonably reflect the utility property that is used and useful at the time rates are placed into effect.

Ms. Shikany sponsored Attachments 4-A-S1 through Attachment 4-C-S1, Attachments 4-A-S2 through Attachment 4-C-S2, Attachment 4-A-S2-A1, Attachment 4-A-S2-A2, and Attachment 4-D. The reference to "S1" represents the attachments for Step 1 rates (based on an actual rate base, and related depreciation and amortization expense, and capital structure as of the

June 30, 2019 proposed cutoff date). The reference to "S2" represents the attachments for Step 2 rates (based on an actual rate base, and related depreciation and amortization expense, as well as the actual capital structure as of the December 31, 2019 Forward Test Year cutoff date). The reference to "A1" represents the attachments for an alternate revenue requirement, in the event that the Commission does not approve the Company's proposed change in service structure. The reference to "A2" represents the attachments for a second alternate revenue requirement, in the event that the Commission does not approve the Company's proposal to extend the collection of coal fired generation depreciation expense until December 31, 2030 and the exclusion of costs to comply with the Asset Retirement Obligations from the demolition study.

Ms. Shikany described the development of the revenue requirements for the Forward Test Year. She stated the proposed revenue requirement was based on NIPSCO's 2019 budget adjusted for ratemaking and service structure adjustments. She noted that for each revenue requirement component, NIPSCO provided support and models to describe the changes from the 2017 actual results to the 2019 forecasted amounts which are used for ratemaking purposes.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to revenue, fuel and purchased power costs, operations and maintenance expenses, depreciation and amortization expense, and tax expense as part of her direct testimony. She also sponsored Rate Base amounts quantifying NIPSCO's December 31, 2019 forecasted net original cost rate base.

Ms. Shikany testified that the retirement of Bailly was accounted for as a normal retirement pursuant to the FERC Uniform System of Accounts. Upon retirement, depreciation reserve was debited and utility plant was credited for the original cost. Treating Bailly as a normal retirement had the effect of assigning sufficient depreciation reserve from other generating stations to Bailly for purposes of the depreciation rates proposed in this Cause, all as explained by Witness Spanos. Certain Bailly assets that were classified as production plant prior to the retirement of the generation units, are now being used as transmission assets. The original cost and accumulated depreciation related to the assets which now comprise the Bailly synchronous condenser were transferred from production plant to transmission plant. She stated that all remaining balances were retired – Bailly Unit 7 in May 2018 and Bailly Unit 8 in February 2018. She stated that NIPSCO removed the original cost of the assets from gross plant and accumulated depreciation at the respective retirement dates of the unit. She testified the remaining net book value of Unit 7 and Unit 8 was a debit balance in accumulated depreciation of $102,923,994 and $142,329,364, respectively. This debit represents unrecovered amounts at the date of the retirement. She stated that until NIPSCO's rates are changed, they are calculated to collect depreciation expense associated with Bailly. Ms. Shikany testified the FERC Uniform System of Accounts prohibits the continued use of the Depreciation Expense and Accumulated Depreciation accounts once an asset is retired. She stated that recognizing that NIPSCO has continued to collect through existing rates the return of depreciation expense through base rates, a regulatory liability has been established to account for this amount. She stated the $28,675,931 regulatory liability reported in Adjustment RB 6-19R is equal to the total amount of depreciation expense that would have been recorded had NIPSCO not retired the assets. She testified in this proceeding NIPSCO is requesting authority to include the regulatory liability as a line item in Accumulated Depreciation, which lowers the net book value of NIPSCO's rate base. She noted that if this adjustment is not included, Forward Test Year Rate Base would be overstated.

Ms. Shikany testified that because the Asset Retirement Obligations are new, estimated costs to close the ash ponds in compliance with the Asset Retirement Obligations have generally not previously been included in the Company's demolition studies and therefore have not been included in the calculation of prior depreciation accrual rates or recovery of depreciation expense. She stated that in the normal course of business, all of the anticipated demolition costs would be included in the demolition study, which is an input in the net salvage calculation in the depreciation study. She explained that depreciation accrual rates would be designed to collect the remaining future accruals, which is equal to the net book value of the asset plus any net salvage, over the remaining useful life of the asset. Ms. Shikany testified that the demolition study sponsored by Mr. Ranalletta (Petitioner's Exhibit No. 12, Attachments 12-A through 12-D) and resulting depreciation accrual rates sponsored by Mr. Spanos (Petitioner's Exhibit No. 13, Attachments 13-B and 13-C) as proposed in this case includes the recovery of anticipated demolition costs, with the exception of costs required to comply with the Asset Retirement Obligations. She stated that NIPSCO has excluded the costs to comply with the Asset Retirement Obligations from the demolition study as the full impact of the regulations is not yet certain and in an effort to reduce the overall base rate increase to customers in this proceeding. She stated that NIPSCO will thus not be recovering through depreciation accrual rates approved in this Cause the costs to comply with the Asset Retirement Obligations. Ms. Shikany testified NIPSCO is filing an alternate demolition study to demonstrate how inclusion of the costs to comply with the Asset Retirement Obligations in the demolition studies would impact the study results. See Petitioner's Exhibit No. 12, Attachment 12-E. She stated that inclusion of the costs to comply with the Asset Retirement Obligations in the demolition studies would increase the total demolition costs for steam production assets by $141,519,000 from $167,232,000 to $308,751,000. She stated that inclusion of the costs to comply with the Asset Retirement Obligations in the demolition studies would increase the remaining future accruals calculated in the depreciation study, which is equal to the net book value of the asset plus any net salvage. She testified that if these additional $141,519,000 costs were collected in the proposed depreciation rates, the annual depreciation expense would increase.

With regard to NIPSCO's announced plan to retire all of the coal-fired generation at Schahfer by 2023 and Michigan City by 2028, Ms. Shikany testified that in the normal course of business, the depreciation study would utilize the physical retirement dates of each generating station unit to calculate the remaining useful life of the unit. The future accrual, which is equal to the net book value of the asset plus any net salvage, would then be divided by the remaining useful life of the asset in order to determine the annual depreciation accrual required to collect all remaining accruals by the physical retirement date. She stated that due to capital additions, the inclusion of costs to comply with the Asset Retirement Obligations in the demolition study, and the acceleration of retirement dates for the coal generation assets the annual depreciation accrual for Total Steam Production Plant increased by $311,908,329 from $132,449,341 in Cause No. 44688 to $444,357,670 in the alternate depreciation study in Petitioner's Exhibit No. 13, Attachment 13-D. She stated that an increase in annual depreciation expense of this magnitude would result in a significant increase in customer rates. Ms. Shikany testified NIPSCO is proposing to mitigate the effects of such a significant rate increase by recovering all remaining future accruals by the end of 2030, as opposed to the physical retirement date of the units. She stated that under this scenario, the Total Steam Production Plant depreciation accrual decreased by $268,567,997 from $444,357,670 in the alternate depreciation study to $175,789,673 in the depreciation study proposed in this case (see Petitioner's Exhibit No. 13, Attachment 13-D). She testified that because the recovery of depreciation expense extends beyond the anticipated physical retirement date of the asset, when NIPSCO retires the coal fired generation units at Schahfer by 2023 there will be a significant amount of remaining net book value. She stated that NIPSCO proposes to treat these retirements as extraordinary retirements. She explained that at the retirement date, NIPSCO would create a regulatory asset equal to the remaining net book value of the Schahfer coal fired generating units. NIPSCO proposes that this regulatory asset be included in rate base and be amortized through December 31, 2030 in an amount equal to the annualized monthly level of depreciation expense based on the month preceding the retirement. She stated that any final true-up between incurred costs and recoveries will be considered in a future base rate proceeding. Ms. Shikany testified that with the exception of the costs to comply with the Asset Retirement Obligations, demolition costs will continue to be recovered through rates as a component of depreciation rates. The costs to comply with the Asset Retirement Obligations, however, will not be recovered through depreciation rates approved in this rate case under this proposal. The costs to comply with the Asset Retirement Obligations will instead be recovered in a future base rate proceeding or by seeking a Certificate of Public Convenience and necessity ("CPCN") to approve the recovery of these costs through NIPSCO's FMCA. Ms. Shikany testified that the retirement will be extraordinary for two reasons. First, the remaining net book value for the coal generation units at Schahfer will be significant. Second, after the retirement of Schahfer in 2023, the only coal fired generation station that will remain is Michigan City Unit 12. She stated that once that unit is retired, there will be no other coal fired generation assets remaining from which depreciation reserve could be reassigned in order to treat the retirement as a normal retirement. Ms. Shikany testified that by extending the recovery of depreciation expense for the Schahfer coal generation units seven years beyond the anticipated physical retirement, NIPSCO will delay the recovery of these dollars to mitigate a significant increase in customer rates. She stated that in the normal course of business, all remaining future accruals would be recovered as depreciation expense through base rates over the remaining useful lives of the plants (anticipated physical retirement dates). If NIPSCO delays the cash recovery of these dollars for an additional seven years, the Company should be compensated by earning a return on remaining net book value in a future rate case. Ms. Shikany stated that the Commission's approval of the proposed depreciation accrual rates in this proceeding would prevent a significant increase in customer rates. She stated that in order to mitigate the Company's financial risk, NIPSCO is seeking authority from the Commission to defer the remaining net book value of coal generation assets as a regulatory asset within rate base. This authority reduces the risk of a GAAP write-off of the remaining net book value of coal generation assets, which would have a negative impact on the financial statements and the investor community. Furthermore, a delay in the cash recovery beyond the useful life of the related assets without assurance that the remaining net book value of the coal generation assets as a regulatory asset in rate base could result in a negative impact on NIPSCO's credit ratings resulting in an increase in the Company's cost of capital. She stated that NIPSCO maintains that the inclusion of this regulatory asset in NIPSCO's next base rate proceeding will alleviate these financial pressures by providing NIPSCO a return on its prudently incurred investments along with predictable and stable levels of cash flow through 2030.

Ms. Shikany described the adjustment made to the Utility Plant In Service component of rate base. She testified one of those adjustments is for the prepayment for cloud based assets relating to NIPSCO's investment in a new cloud based Procure-to-Pay ("P2P") system. She explained that the new system will allow for replacement of multiple, fragmented and obsolete technology systems related to sourcing, procuring and paying for goods and services and also allow the Company to automate and standardize business processes, manage standard settlement terms with suppliers, take advantage of new methods of settling payments, leverage centralized purchasing data and manage spend on goods and services. She stated that NIPSCO has identified cloud computing services as a means to enhance security, and increase reliability and flexibility. As a result of these benefits, cloud based technologies are becoming more prevalent. She stated that to realize these benefits, NIPSCO plans to utilize cloud based technologies beyond the P2P system. Ms. Shikany testified NIPSCO is requesting authority to account for off premise cloud based technology solutions in the same way that it accounts for on premise technology solutions. She explained that this would mean that the Company would capitalize implementation services, internal labor, and other fees (such as those for licenses, maintenance and support) that were necessary to bring the asset into service in FERC Account 303, Intangible Plant, for ease of tracking and identification. She explained that under the current GAAP accounting guidelines, certain costs incurred for the development of on premises software are required to be capitalized, while certain implementation costs for cloud based services are considered prepaid expenses. Many cloud based services offer advantages to traditional on-premises software such as greater flexibility for the workforce, improved productivity, and higher efficiency at lower costs relative to certain on-premises solutions. Accordingly, since cloud based prepaid expenses (such as the P2P system) are expected to provide benefits over extended periods of time and not just in the period in which the costs are incurred, the Company believes that the prepaid expenses should be included in rate base and receive the same regulatory treatment as an on-premises solution, which is capitalized in FERC Account 303, Intangible Assets. Ms. Shikany testified that NIPSCO believes that investments in prepaid expenses related to cloud based assets are part of the reasonable cost of bringing NIPSCO's property to its current state of efficiency. She stated that NIPSCO has identified cloud computing services as a means to enhance security, and increase reliability and flexibility. As a result of these benefits, cloud based technologies are becoming more prevalent. To realize these benefits, NIPSCO plans to utilize cloud based technologies beyond the P2P system. When selecting the cloud-based technology for the P2P solution, the Company also considered an on-premises option. Ms. Shikany testified the Company proposes to amortize off-premises assets over the period of time that NIPSCO will use the new solution. In this case, the contract period for the cloud based solution is five years so a five year period will be used to amortize the asset.

Ms. Shikany described NIPSCO's proposed changes to its currently approved riders. NIPSCO is proposing all Utility Receipts Tax will be removed from the Riders as NIPSCO is proposing that URT will be a separate line item on the customer bill. NIPSCO is proposing to update Rider 770 – Adjustment of Charges for Cost of Fuel Rider to update the cost of fuel included in base rates. NIPSCO also is proposing to update Rider 771 – Adjustment of Charges for Regional Transmission Organization to reflect updated base levels of MISO non-fuel costs and revenues and OSS margins and proposing the pass back of any back up and maintenance demand revenue. Finally, NIPSCO is proposing to eliminate the ECR Mechanism.

Ms. Shikany testified NIPSCO is seeking accounting authority to (1) defer, as a regulatory asset, discounts offered to certain customers under its EDR for recovery in a future rate case, (2) defer, as a regulatory liability, an amount equal to 100% of (a) annual OSS margins net of expenses and (b) back up and maintenance demand margins, both for pass back through the RTO Tracker, and (3) defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. She testified such deferred accounting is consistent with GAAP and FERC Uniform System of Accounts.

Ms. Shikany testified that in March of 2017, the Financial Accounting Standards Board issued ASU 2017-07, a GAAP standard which changed the income statement presentation of Pension and OPEB expense and limited the amount of expense eligible for capitalization. She stated the new GAAP standard requires disaggregation of the cost components of Pension and OPEB and only the service cost component will be eligible for capitalization to Property, Plant and Equipment. NiSource adopted the standard January 1, 2018. She testified NIPSCO is accounting for the costs consistent with guidance from the FERC Docket No. AI18-1-000, which states "Jurisdictional public utilities and licensees, natural gas companies, and centralized service companies should record pension and post-retirement benefits other than pensions costs in their entirety in Account 926". She explained that based on this FERC Docket, the ASU 2017-07 GAAP changes need not apply to the FERC books and that all components of Pension and OPEB costs that have historically been reported in operating expenses will continue to be recorded in operating expenses.

Ms. Shikany supported NIPSCO's calculation of the 2018 and 2019 WACC shown on Attachment 4-B-S2, CS Module. She explained that the forecasted Prepaid Pension Asset represents the difference between the forecasted cumulative amount of cash contributions to NIPSCO's pension trust fund and the forecasted cumulative amount of pension expense that will be recorded on NIPSCO's books and records in accordance with Generally Accepted Accounting Principles ("GAAP"). She stated that the Company has included the balance of the Prepaid Pension Asset as a component of NIPSCO's overall WACC.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to its proposed capital structure in her direct testimony.

Ms. Shikany stated that NIPSCO's accounting and financial reporting policies and procedures conform to GAAP, rules of the Securities and Exchange Commission, and the FERC Uniform System of Accounts. In addition, she explained that NIPSCO's (and NiSource's) financial books and records are formally audited by its outside auditors, and these outside audits are supplemented by internal audits. She also discussed the various controls NIPSCO utilizes to ensure the accuracy of its accounting books and records and financial statements. She testified NIPSCO's books and records are also subject to audit by the OUCC, the Commission and FERC.

E. Clifton Scott. Mr. Scott explained and supported (1) the financial planning and budgeting processes used at NIPSCO, (2) NIPSCO's 2018 Annual Financial Plan ("AFP") for its electric utility, which is the underlying basis for the rate request in this proceeding (the "2018 AFP"); and (3) the 2018 and 2019 budget adjustments not supported in other witnesses testimony. He summarized the processes used at NiSource and NIPSCO for development of capital and O&M budgets, as well as longer-term financial plans. He explained the rigorous process that is used at NiSource and NIPSCO to develop robust and accurate budgets and financial plans, including engaging leadership and operations personnel and prioritizing safety, reliability, customer service, and compliance. He stated NIPSCO's budgeting process produces budgets that are reliable forecasts of future capital and O&M needs and expenditures.

The 2018 AFP, which covers plan years 2018 and 2019, is the underlying basis for the rate request in this proceeding.

Mr. Scott testified the revenue forecasting methodology results in an accurate estimate of revenues to be achieved during 2019, with the caveat that the revenue forecast presented in this case does not reflect proposed or anticipated revenues coming out of this proceeding. A key component of forecasted revenues is the amount of forecasted customer energy usage discussed by NIPSCO Witness Strauss. Mr. Scott testified that under current rates, NIPSCO Electric's revenues in 2019 are forecasted to be $1,776,342,377 based on the major assumptions used for customer usage volumes, cost of fuel and purchased power, and approved retail electric utility tariff rates.

Mr. Scott testified the O&M budgeting methodology results in an accurate estimate of expenses to be incurred during 2019. He stated NIPSCO Electric has experienced a variance of 0.2%, compared to its approved O&M budget over the last five years and demonstrates a high level of historical O&M budgeting accuracy by NIPSCO Electric. He concluded that these results should provide a high level of confidence and reliability as to the overall accuracy of the O&M expenses included in NIPSCO Electric's 2019 O&M budget.

Mr. Scott testified the capital budgeting methodology results in an accurate estimate of capital to be expended during 2019. He stated NIPSCO Electric has experienced a variance of 1.1%, compared to its approved capital budget over the last 5 years. He testified this variance demonstrates a high level of historical capital budgeting accuracy by NIPSCO Electric. He concluded that these results should provide a high level of confidence and reliability as to the overall accuracy of the capital expenses included in NIPSCO Electric's 2019 capital budget.

Mr. Scott testified NIPSCO Electric's 2019 forecasted income statement and consolidated balance sheet were prepared in accordance with NIPSCO's normal forecasting processes and based on the consolidation of data provided by business units and various corporate departments. The forecast is fully integrated between the income statement, balance sheet and statement of cash flows. He testified NIPSCO's forecasted consolidated 2019 statement of cash flows is a function of the items reflected in the forecasted balance sheet.

Mr. Scott described the major components of NIPSCO Electric's fuel and purchased power expense. He testified NIPSCO Electric's fuel and purchased power expense in 2019 is forecasted to be $486,393,871.

Mr. Scott described the major categories of NIPSCO Electric's O&M expenses as generation, transmission, distribution, operating and maintenance expenses, customer account expenses, and administrative and general expenses. Mr. Scott testified NIPSCO Electric's O&M expenses in 2019 are forecast to be $557,756,972.

Mr. Scott described the major components of NIPSCO Electric's tax expenses other than income taxes to be property taxes, payroll taxes, public utility fees, and utility receipts taxes. He testified NIPSCO Electric's tax expenses, other than income taxes, in 2019 is forecast to be $66,011,931.

Mr. Scott stated the major components used in the development of the forecasted 2019 capital expenditures are Growth (also referred to as New Business), Tracker, Maintenance Betterment (capacity or compliance), Replacement (age and condition), Public Improvement (mandatory relocation), and Corporate (Shared Services). He testified NIPSCO Electric's capital expenditure in 2019 is forecast to be $417,526,573.

He testified NIPSCO Electric's Materials and Supplies and Production Fuel balances are $105,237,192 and $45,253,522, respectively.

Mr. Scott explained the major components of NIPSCO Electric's capital structure consist of Common Equity, Long-Term Debt, Customer Deposits, Deferred Income Taxes, Post Retirement Liability, Prepaid Pension Asset and Post-1970 ITC. He testified NIPSCO's capital structure balances in 2019 are forecast to be $5,932,644,938.

F. <u>Patrick N. Augustine</u>. Mr. Augustine provided an extensive discussion of the analysis that was performed in NIPSCO's 2018 IRP and explained how that analysis was used in making the retirement decisions regarding NIPSCO's coal facilities. He stated that all five of NIPSCO's coal-fired units were evaluated for retirement, including Michigan City Unit 12 and Schahfer Units 14, 15, 17 and 18. He explained that the operational dependency as well as technology and vintage similarity of the units at Schahfer would make unit level retirement impractical at that plant and as a result, the analysis created two unit pairs that would be jointly considered for retention or retirement at Schahfer – Pair 1 matched Units 14 and 15, and Pair 2 matched Units 17 and 18. He stated that analyses were performed for NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. He stated that NIPSCO used a number of factors in analyzing the retirement timing of the coal units including customer cost, cost risk, reliability risk, and impacts to NIPSCO's employees and the local economy.

Mr. Augustine described that customer cost and cost risk are measured by the overall Net Present Value of Revenue Requirements. He explained that the Cost to Customer metric is recorded under a Base Case set of market conditions. In addition, he noted that NIPSCO evaluated customer costs across three alternative market scenarios and at different points on a cost distribution developed through a stochastic analysis (referred to as Cost Risk and Cost Certainty). He explained that Reliability Risk assesses NIPSCO's ability to confidently transition the resources and maintain customer and system reliability and considers the activities required as part of the MISO retirement process, potential transmission system and reliability upgrades that are required as a result of plant retirements, remaining unit dependencies, outstanding fuel and other contracts, future resource procurement, and the percent of NIPSCO's supply resources turning over at once. He noted that other factors, such as the loss of work for employees and the reduction of property tax base for surrounding communities, also factored into NIPSCO's decision making process. He said that while these do not directly impact power supply costs to customers, NIPSCO believes they are factors that should be included in the analysis.

Mr. Augustine described that the retirement analysis evaluated eight (8) retirement combinations and that the projected future capital and operating costs for the affected units were modeled in by CRA in the Aurora production cost and utility portfolio model. He explained that the economic analyses ultimately compare the ongoing costs and benefits of operating the existing units to the costs and benefits of retiring and replacing the relevant unit or sets of units with alternatives. He stated the analyses were evaluated across all scenarios and stochastics developed in NIPSCO's IRP.

Mr. Augustine testified that capital cost estimates were developed by operational teams within NIPSCO for existing unit maintenance and environmental spend as well as for necessary transmission reliability upgrades in the instances where certain coal units retired. He stated that the existing rate base was depreciated at NIPSCO's latest estimate for the steam generation fleet average, which is 4.6%, across all retirement portfolios, which is consistent with the depreciation study presented in this Cause. He indicated that existing rate base is depreciated at the fleet average depreciation rate until the book value is equal to the total estimated "cost of removal," which is equal to $227 million for the entire fleet. He said that this depreciation schedule and cost of removal value were the same across all retirement cases; thus, the analysis assumes that return of and on capital is recovered in all cases. He noted that when a unit retires, certain property and income taxes associated with the unit are assumed to be eliminated, but all depreciation expenses and capital charges associated with NIPSCO's invested capital on the plants is still recovered.

Mr. Augustine provided an extensive explanation of the resource alternatives used to evaluate the retirement options, the commodities price assumptions used in the analysis, and the process CRA used to complete the modeling analysis. He also addressed how risk and uncertainty were assessed in the analyses. Mr. Augustine sponsored the detailed modeling results in Attachment 6-A. He testified that in the Base Case, Retirement Combination 8 (where 100% of the coal portfolio is retired by 2023) is the lowest cost option, and Retirement Combination 1 (where all coal units run to 60 years of service) is the highest cost option. He testified that in the Base Case, Retirement Combination 6 (which retires Schahfer Units 14, 15, 17 and 18 in 2023, and Michigan City Unit 12 in 2028) is the third lowest cost option. He explained that the cost to customer ranking remains broadly consistent across the four (4) scenarios analyzed. He explained that generally, portfolios that retain more coal perform relatively better in the scenario without a carbon price (Challenged Economy) and relatively worse when carbon prices are higher (Aggressive Environmental Regulation); however, in all four (4) of the scenarios, retirement of all coal units (Retirement Combination 8) and replacement with a model-optimized selection of Request for Proposals ("RFP") alternatives is the least cost portfolio and that Retirement Combination 6, is the third-least expensive option. He testified that overall, the analysis concludes that the all-in costs of the replacements evaluated from the RFP are lower than the ongoing costs associated with maintaining the existing coal fleet. Mr. Augustine also described the results of the IRP analyses with regard to the other, non-cost metrics.

Mr. Augustine testified how NIPSCO integrated the results of these analyses to arrive at a decision regarding coal retirements. He stated that NIPSCO created a scorecard to explore relative differences between the portfolios using a number of quantitative and qualitative measures. He stated that ultimately, NIPSCSO selected retirement combination 6 as the preferred retirement path, which would retire all of the Schahfer units by the end of 2023 and Michigan City by the end of 2028. He explained that combination 6 was selected because it was the lowest cost and lowest cost risk option that held acceptable reliability risk for customers and the system. He said the analysis shows that Combination 6 saves customers $1.5 billion relative to NIPSCO's 2016 IRP preferred plan and that from a reliability risk standpoint it provides enough time to reasonably erect the necessary transmission upgrades that are critical for system and customer reliability. Additionally, the replacement resources can be reasonably secured and constructed by 2023. He stated that while the near-term transition still encompasses roughly 60% of NIPSCO's physical generation, it maintains Michigan City through 2028 and Sugar Creek Generating Station ("Sugar Creek") even longer. He noted that both are dispatchable units that can be used to support the transition while NIPSCO implements the replacement path. He also indicated that another benefit of staggering the retirements is that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade and adjust as appropriate rather than locking the entire transition in at once.

Mr. Augustine concluded that NIPSCO evaluated its generation portfolio under four (4) separate fundamental market scenarios as well as with advanced risk treatment using stochastics. He stated that Retirement Combination 6 was selected as the preferred retirement portfolio combination. He testified that in this option, NIPSCO has balanced customer cost and cost risk with portfolio flexibility and the ability to successfully and reliably transform its supply resources to meet its customers needs. He noted that although not the least expensive solution, in all modeling analyses, the preferred portfolio results in savings to customers, greater cost certainty and lower cost risk over alternatives that preserve more coal capacity for longer, as well as balancing other non-economic considerations such as portfolio flexibility, employees, and local property tax impacts.

G. Michael Hooper. Mr. Hooper adopted the testimony of Benjamin Felton, formerly NIPSCO's Senior Vice President, NIPSCO Electric, and that testimony was offered separately. In that testimony, Mr. Hooper described steps taken by NIPSCO to control costs, described NIPSCO's generation fleet, described NIPSCO's electric transmission and distribution systems, discussed the Company's customer service and electric reliability programs, and described the significant investments NIPSCO has made to its generation and transmission and distribution systems in recent years, and explained and supported several various pro-forma expense adjustments.

Mr. Hooper testified that NIPSCO's Net Utility Plant has grown by approximately $360 million or 12% over the last 3 years and is projected to grow by another $520 million by the end of the 2019 future test year. He noted that NIPSCO has taken steps to control costs resulting in decreases to O&M expenses, but explained that in spite of these efforts, increases in depreciation and amortization expense associated with the investment in new plant are projected to counter those savings. Mr. Hooper testified that managers in charge of each department or cost center must prepare and submit proposed operating budgets to include proposed levels of capital and operating expenditures. He explained that each operating budget is reviewed by management and that once approved by management, each manager is responsible for monitoring their budget to ensure the costs are spent within approved limits. Budgets and actual expenditure variances are reviewed throughout the year to ensure that funds are being spent appropriately and in accordance with approved levels to ensure that controls are in place to identify, monitor and control costs.

Mr. Hooper described NIPSCO's six electric generation sites totaling 2,825 MW, including the Schahfer, Michigan City, Bailly, Sugar Creek stations and two hydroelectric dams. He testified that NIPSCO's historic test period generating mix produced 73.3% of its output from coal-fired units, 26.3% from natural gas-fired units, and 0.4% from hydroelectric units. He noted that the

Bailly Units 7 and 8 were retired on May 31, 2018 consistent with NIPSCO's expectations expressed in Cause No. 44688.

Mr. Hooper discussed NIPSCO's investments in environmental and emissions control projects and included tables in his testimony identifying the capital cost associated with each. He testified that NIPSCO obtained approval of its Environmental Compliance Plan consisting of several capital projects being tracked through NIPSCO's FMCA Tracker, noting that with one exception all projects incorporated in that Plan would be in service prior to the close of the Forward Test Year. He also detailed the components of the Utility Mercury and Air Toxics Standards ("MATS"), nitrogen dioxide ("NOx"), and MPCP Compliance Plans that had previously been the subject of approved CPCNs with costs for those projects recovered through NIPSCO's ECR tracking mechanism. Mr. Hooper testified that each of the components of the three environmental compliance Plans was in service and used and useful in the provision of electric service because they have or will assist NIPSCO in meeting increasingly stringent air emissions requirements. Mr. Hooper also identified other capital improvements made and to be made to NIPSCO's generation fleet since NIPSCO's last base rate case not already included in either the FMCA or ECR tracking mechanisms, and explained that each of those improvements is expected to be in service by the close of 2019.

Mr. Hooper summarized that the reliability of NIPSCO's generating units (exclusive of Units 7 and 8) as measured by the Equivalent Forced Outage Rate ("EFOR") has increased relative to the 44688 Rate Case, with the Company's average EFOR for the three year period ending December 31, 2017 increasing to 10.6% with the limited run time for the coal units during this period due to economic dispatch into MISO as a contributing factor. He explained that EFOR expresses unit reliability as a percentage of available run time for unplanned outage hours and equivalent unplanned de-rated hours. In contrast to NIPSCO's coal units, NIPSCO's Sugar Creek combined cycle gas turbine has been below 2.5% EFOR for each of the preceding three years, and under 1% in 2016, with a net capacity factor consistently above 65% and as high as 84% as of June 2018. He testified that the EFOR of NIPSCO's coal units was 9.79% in 2017, below the 2017 U.S. average of 10.92% for similarly sized units of between 300 – 599 MW.

Mr. Hooper explained that during the three year period 2015 – 2017, NIPSCO's average EFOR was 10.63%, still slightly lower than the 2017 national average. He noted that with recently announced coal plant retirements, there is the potential for EFOR to move upward over the near to medium term. Mr. Hooper explained that NIPSCO will continue to operate its facilities in a safe, environmentally compliant manner and with a reasonable level of reliability, while making sound decisions with regard to significant capital investments into facilities with limited operating lives. He testified that because NIPSCO's coal units were engineered to be used as base load units that run consistently over long periods of time, as those units become less economical, the cost to operate them increases because in addition to the increased maintenance required of older units, the added expenses to ramp the units up and down are incurred more frequently. He explained that NIPSCO must remain mindful of the balance between the added expense to customers and the impact on reliability because the operational characteristics of the plants dictate that some increases in costs cannot be avoided when the plants are operated outside of the parameters of their design.

Mr. Hooper also addressed NIPSCO's base cost of fuel and coal inventory levels in his direct testimony. He testified that the adjusted retail jurisdictional cost of fuel in the Historic Base Period reported in Petitioner's Exhibit No. 4, Attachment 4-B-S2, FP Module was $494,884,095. He opined that this value was reasonable as discussed in NIPSCO's quarterly FAC proceedings. He added that both NIPSCO's long term coal contracts and shorter term gas supply contracts were the result of competitive bidding, and that NIPSCO considers a number of factors in making fuel procurement decisions, including price, quality, suitability, environmental attributes, supplier availability, reliability, and diversity in addition to market prices. Mr. Hooper testified that NIPSCO's retail jurisdictional coal inventory level reported in Petitioner's Exhibit No. 4, Attachment 4-B-S2, RB Module for the Historic Base Period was $80,046,953, and that it was reasonable and consistent with the NIPSCO's desire to have adequate fuel supplies on hand while balancing the costs associated with maintaining coal inventory.

NIPSCO's safety culture was also discussed by Mr. Hooper in his direct testimony. Mr. Hooper described how NIPSCO, with the assistance of a consultant, derived a plan to deliver human performance based error reduction into the fabric of the Company through the use of improved safety metrics and a focus on an improved safety culture. He explained that in the past year, NIPSCO has engaged other consultants with expertise in safety regulations to work with internal teams to review and refine internal work practices, safety manuals, and safety policies/procedures while ensuring alignment with industry standards and best practices. He testified that NIPSCO has also participated in the National Safety Council's *Journey to Safety Excellence* program whereby NIPSCO undertakes an annual employee survey that is focused only on safety culture and is benchmarked against over 800 other survey participants worldwide. He also explained that NIPSCO continues to collaboratively work with its front line employees to develop rules and policies for stronger work practices, and has developed a number of in-house safety training programs to improve driving performance and regulatory changes and requirements are continually monitored to manage safety training on a continual improvement basis.

Mr. Hooper testified that NIPSCO's contractors and construction execution teams have been engaged in its efforts to strengthen the safety culture, and NIPSCO has supported such measures as formation of cooperative contractor safety committees for both its generation and field operations teams that are involve leaders from each of NIPSCO's major contractor teams. He added that NIPSCO's focus on cooperation and safety has resulted in very strong safety performance from its contracted teams. He testified that NIPSCO has made an 80% improvement in recordable injury rate, an 83% improvement in DART (days away, restriction or transfer) injury rate, and a 71% improvement in vehicle crash rate from year end 2008 to year end 2017, including a 66% improvement in recordable injury rate, a 72% improvement in DART injury rate, and a 71% improvement in vehicle crashes during that period on the electric operations side of the business.

As part of his direct testimony, Mr. Hooper described NIPSCO's transmission and distribution systems. He explained that NIPSCO's transmission system consists of approximately 353 circuit miles of 345 kV, 756 circuit miles of 138 kV and 1,693 circuit miles of 69 kV transmission lines in addition to 63 transmission substations. He testified that NIPSCO is interconnected with six neighboring utilities, with transmission interconnects with American Electric Power or its affiliates (at 345 kV, 138 kV, and 69 kV operating voltages), interconnects with Commonwealth Edison (at 345 kV and 138 kV), and with Duke Energy Indiana (at 345 kV, 138 kV and 69 kV), in addition to single 138 kV interconnections with both Ameren and

International Transmission Company and a single 765kV interconnection with Pioneer Transmission. He described NIPSCO's distribution system as serving more than 468,000 customers in Northern Indiana, primarily through more than 900 distribution circuits operated at nominal voltages of 34.5 kV, 12.5 kV, and 4 kV radiating from approximately 240 distribution substations, and encompassing about 8,209 miles of overhead line and about 2,532 miles of underground cable.

Mr. Hooper described the electric transmission and distribution investments made by NIPSCO since its 44688 Rate Case. These included investments in an Enhanced Outage Management System to provide faster restoration and more accurate communication of restoration timing scheduled to be in service in early 2019, more than $283 Million in transmission, distribution, and storage system improvement charge ("TDSIC") direct cost investments through May 31, 2018, and other maintenance capital investments to expand and enhance system capacity and reduce system risk. Mr. Hooper explained that while significant investment had also been made in multi-value projects through MISO, those investments were not being included in jurisdictional rate base. He testified that all of NIPSCO's other transmission and distribution assets inclusive of the non-MVP additions are essential to the reliable transport and delivery of electricity from NIPSCO's generation fleet or from other generators to its retail customers in order to meet customers' needs for electric power, and are used and useful in the provision of electric service.

Mr. Hooper explained that NIPSCO monitors three main metrics to evaluate the reliability of the transmission and distribution system: SAIFI, SAIDI and CAIDI. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year. CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. Mr. Hooper testified that all three reliability indices have improved since the 44688 Rate Case and from 2014 to 2017. He explained that reliability indices are reported by industry standard without including Major Event Days, primarily storms or severe weather events more destructive than typical storm events. He noted that the decrease in Major Event Days in recent years is likely due in part to NIPSCO's aggressive vegetation management program and implementation of a comprehensive emergency restoration plan in 2017. He concluded that NIPSCO's transmission and reliability metric performance has been at or above industry standard performance for medium sized electric utilities for the past 5 years.

Mr. Hooper testified about the programs NIPSCO uses to support transmission, distribution, and substation reliability and ensure compliance with North American Electric Reliability Corporation ("NERC") standards. Among the programs he discussed were wooden pole inspection, and vegetation management programs along with periodic inspections and maintenance of transmission lines and structures, substation equipment, protective relay systems, and distribution pad-mount transformers, pole-mounted re-closers, voltage regulators, switched capacitors, and other underground equipment that include remedial work necessary to repair or replace minor plant items found to be deficient from inspection criteria. In 2017, NIPSCO developed and implemented a robust emergency response plan, and NIPSCO has also developed a formal Outage Investigation Program that reviews any outages that impact more than 1,000 customers, result in a pole fire or similar safety-related event, or have an outage cause code of "unknown." Lineman, Substation Electricians, Supervisors, Dispatchers, and Engineers all benefit from these report findings by applying these lessons learned to their designs, materials, and construction methods to improve reliability, and more accurately perform analytics on its outage causes and make improved decisions on materials, designs, construction methods, and maintenance techniques.

He also described NIPSCO's Line & Sub voltage regulator maintenance replacement program to reduce in service failures. He testified that the program is intended to lead to enhanced customer reliability by incorporating regulators of newer design with enhanced tap changers that reduce contact wear and thus premature failure, and added that microprocessor based controls have proven to be more reliable than analog controls, with the added benefit of enhanced customer voltage profile. He explained that NIPSCO has continued its "Worst Circuits" and "Worst Taps" Programs whereby circuits with the worst performance values are then assessed and recommendations for improvement are developed and taps that have experienced multiple outages in the previous year are identified and recommendations for improvement developed. Mr. Hooper noted that recommendations flowing from those programs have included targeted tree trimming, replacement of equipment prone to failure, replacement of equipment that is in poor condition, an analysis of fuse coordination and loading, and installing additional sectionalizing devices (cut-outs, triple-shots, re-closers, switches, etc.) where appropriate to minimize the impacts of outages and the number of customers affected per outage. Mr. Hooper explained NIPSCO's investment in an Enhanced Outage Management System expected to go into service in early 2019 to improve customer experience the foundational platform to drive dependable, predictable, timely service and emergency response by providing for faster restoration and more accurate communication of estimated time of restoration during planned and unplanned outages.

Mr. Hooper also discussed enhancements to NIPSCO's Mobile user application to include the cause of outage when the estimated time of restoration is pushed out to all electric customers that have supplied NIPSCO with an email address. He testified that key elements of NIPSCO's annual operating plan focus on service and reliability improvements, and that specific performance targets are cascaded throughout the organization in an aligned and increasingly more specific manner, becoming a core part of NIPSCO's annual performance management process with targets for specific reliability and safety metrics incorporated into performance expectations for his leadership team and his organization.

In his direct testimony, Mr. Hooper provided detailed support for a number of proposed adjustments found in <u>Petitioner's Confidential Exhibit No. 20-S2</u>. He testified that Adjustment OM 2A-17 increases non-labor Storm expense for the Historic Base Period by $1,336,602 to approximate a 5 year average of storm expense, adding that both 5- and 7-year analyses produced similar results. He explained that the Historic Base Period was a mild storm year, so Adjustment OM 2A-18 increases the 2017 normalized expense by $74,979 to reach the 5 year average of $3,056,037 included in the 2018 Budget Period. Mr. Hooper also addressed the elimination of the Pure Air expenses in the amount of $10,702,282 and $8,568,689 for 2018 and 2019, respectively, because with the retirement of Bailly Units 7 and 8 the Pure Air FGD facility will no longer be required to operate so the associated expenses will no longer be incurred.

Mr. Hooper testified that Adjustment OM 2C-18 reduces forecasted Generation Base Maintenance expense by $6,785,009 as a reflection of (a) a $1.9 million budget reprioritization decision, (b) a $2.4 million pull forward of 2018 budgeted dollars for the pre-purchase of materials, and (c) a $1.1 million reduction in planned outages. He explained that while operationally advantageous, they were isolated opportunities and should therefore not be reflected in the ongoing level of operating expenses. He added that Adjustment OM 2C-19 reflects an increase of $1,590,485 to reflect 2019 increases in cooling water chemical expenses anticipated for 2019. Mr. Hooper also discussed adjustments OM 2D-18 and OM 2D-19 to reduce Bailly non-labor Base Maintenance Expense by $3,600,000 and $3,800,000 in 2018 and 2019, respectively, due to the retirement of Bailly Units 7 and 8. He explained that the $3,600,000 reduction to the 2017 represents seven months of savings based on the retirement of the units in May, and that an additional $3,800,000 of savings in 2019 will bring the total Bailly Base Maintenance Expense savings to $7,400,000. He noted that the remaining Bailly base maintenance budget of $848,092 will be used to maintain the synchronous condenser unit and the Unit 10 combustion turbine that will remain in service.

Mr. Hooper addressed adjustments to NIPSCO's Planned Outages normalization presented in Adjustment OM 2E-17 and its ongoing level of Planned Outages expenses in Adjustments OM 2E-18, 2E-19, and 2E-19R. He explained that Adjustment OM 2E-17 reduced the normalized level of Planned Outages for the base period by $25,455 based on the retirement of Units 7 and 8. He testified that Adjustments OM 2E-18 and OM 2E-19 reflect changes in amounts budgeted for 2018 and 2019 because the planned outage schedule varies from year to year by station, unit, and major component, and that Adjustment OM 2E-19R normalized non-Bailly planned outage expenses going forward to a three year average of $30,437,740. For Forced Outages expenses, Mr. Hooper explained that Adjustment OM 2F18 reflects an increase of $119,959 to reflect 2018 budget expenditures, and Adjustment OM 2F-19R increases the ongoing level of Forced Outages expense to the average value of $5,261,129 actually experienced from 2015 through 2017.

Adjustments OM 2G18, OM 2G-19 and OM 2G-19R proposed adjustments to NIPSCO's Vegetation Management expenses, and the rationale for each was described by Mr. Hooper in his direct testimony. Mr. Hooper explained that since its last electric rate case, NIPSCO has increased the budget portion of its 69 kV, 34 kV, and 12 kV vegetation management programs to include more circuit line miles and has begun analyzing circuits on a yearly basis to determine which circuits have had a higher experience of interruptions regardless of when the circuit was last trimmed. He explained that those circuits are surveyed, sources of tree interruptions identified, and remedial work performed and that when compared to the same time frame (January through June) as last year, NIPSCO has experienced an overall reduction in tree related outages and number of customers impacted. He testified that in 2017 NIPSCO began to experience higher external labor and equipment costs to perform clearance work due to market conditions, and that those changes were reflected in Adjustments OM 2G-18 and OM 2G-19 that increase Historic Base Period non-labor vegetation management expenses for 2018 and 2019. He noted that while NIPSCO has been prudent in managing vegetation costs, the overall impact of market constraints would lead NIPSCO to fall approximately 500 miles short of its 2019 circuit mileage goal at current funding levels so Adjustment OM 2G-19R was made to increase vegetation management expense by $5,720,500 to permit it to retain the 1,500 mile goal for 2019 allowing NIPSCO to continue to reduce vegetation related outages.

Mr. Hooper also supported Adjustments OM 2H-17, OM 2H-18 and OM 2H-19R for Line Locate expenses. He testified that Adjustment OM 2H-17 decreases the Historic Base Period operating expense by $128,042 to reflect a full year of pricing and efficiencies gained under the terms of two locate contracts that became effective on March 8, 2017. He explained that the average ticket cost under NIPSCO's new locate contracts is $29.38 per ticket for combination gas and electric locates and $12.93 per ticket for electric only locates in comparison to the cost under the previous contract of $19.90 per ticket, and the incremental cost per ticket was then multiplied by the number of locates in the twelve month period between May of 2017 and April of 2018 to capture a full 12 month period of actual data to develop the normalized value. Mr. Hooper explained that Adjustment OM 2H-18 decreases the normalized Historic Base Period line locate expense by $522,189 to reflect the amount budgeted for line locating in 2018, and that Adjustment OM 2H-19R increases future test year locate expenses by $1,489,294 to reflect an increase in the projected number of 811 tickets in 2019 based on a projected increase in volume of 10.3% per year over the Historic Base Period volumes, and an increase of in the cost per. These incremental 811 volumes were multiplied by the 95¢ per ticket and the incremental line locates volumes were multiplied by 2019 average screened prices to calculate the adjustments.

Mr. Hooper testified that Adjustment OM 2I-18 was made to reflect a decrease in Variable Chemical expense in the Historic Base Period by $1,164,262 driven by a change in the mix and quantity of chemicals required upon the retirement of Bailly Units 7 and 8. He explained that Adjustment OM 2I-19R reflects a reduction Variable Chemical expense of $551,509 to levelize it for reduced generation of 6.1 Million MWh in 2019 based on updated PROMOD inputs and to reflect the redistribution of the MWhs produced across NIPSCO's remaining units. According to Mr. Hooper, Adjustment OM 2I-19SS was made to reflect the decrease in Variable Chemical expense for the Forward Test Year based on the proposed change in NIPSCO's service structure and the attendant loss of industrial load. Mr. Hooper also supported Adjustments OM 2J-18, OM 2J-19 and OM 2J-19SS that addressed Activated Carbon Injection ("ACI") expenses. He testified that Adjustment OM 2J-18 adjusted Historic Base Period ACI expenses to reflect reduction in ACI expenses as a result of the closure of Units 7, and 8 and an increase in ACI expenses at other units including increases associated with the increased output at Unit 15 during the Historic Base Period. The overall adjustment was an increase of $568,111. Mr. Hooper explained that Adjustments OM 2J-19R and OM 2J-10SS reflect a decrease in projected ACI expense for 2019 of $193,163 reflecting a projected decrease in Unit 15 output and Adjustment OM 2J-19SS reflects a slight increase in projected ACI expense of $48,158 as a result of the implementation of NIPSCO's proposed service structure.

Mr. Hooper discussed the Long Term Service Agreement ("LTSA") for Sugar Creek in his direct testimony, explaining that those expenses are incurred based on the Runt Time of the unit. He explained that Adjustment OM 2K-18 reflects an increase to the Historic Base Period of $115,416 in LTSA expenses for the 2018 budget based upon the increased Run Time of the Sugar Creek units, and that Adjustment OM 2K-19R was a ratemaking adjustment made to reflect changes in the LTSA contract executed after the preparation of the 2019 budget that decreases annual LTSA expenses by $3,774,547. He also sponsored Adjustment OM 2L-17 to decrease Historic Base Year Miscellaneous Expenses by $1,379,154 to remove expenses not budgeted as ongoing expenses.

Mr. Hooper explained that NIPSCO adjusted its projected 2019 O&M expenses downward by $3,890,900 to annualize the impact of a variety of cost savings initiatives including the use of a number of contracting options with vendors as well as in-sourcing some activities to increase efficiency. He also sponsored Adjustment OM 4B-19R to increase Forward Test Year operating expenses by $8,228,823 to reflect the ongoing level of O&M expenses associated with NIPSCO's MATS Compliance Project and MPCP Project currently being recovered through NIPSCO's ECRM. He explained that these costs will no longer be recovered through the ECR Tracker once new rates are implemented, and noted that all costs for compliance with MATS associated with Bailly have been removed. Mr. Hooper also testified that Adjustment OM 4-19SS reflects an increase in the on-going level of O&M expenses associated with NIPSCO's MATS Compliance Project and MPCP Project by $24,124 to reflect the implementation of the proposed service structure and the loss of load associated with NIPSCO's largest industrial customers.

Mr. Hooper testified that Adjustment OM 5-18 and OM 5-19 increase the Historic Base Period by $4,039,088 and 2,384,304, respectively, for budgeted increases in FMCA tracker expense, and that OM 5B-19R increases Forward Test Year operating expenses by $8,344,575 to reflect the ongoing level of O&M expenses associated with NIPSCO's NERC Compliance Project currently being recovered through NIPSCO's FMCA. Upon implementation of new base rates, these costs will no longer be recovered through the FMCA Tracker.

H. Kelly R. Carmichael. Mr. Carmichael provided testimony about the current, major environmental regulations with which NIPSCO must comply and proposed regulations that NIPSCO anticipates will be implemented in the near term. He also addressed how NIPSCO has evaluated the cumulative impact of increasingly-complex future environmental requirements on its resource planning and the increased operating pressure such regulations place on existing coal-fired plants.

Mr. Carmichael explained the environmental drivers for the cost increases that NIPSCO has experienced since its last rate case was filed in 2015. Specifically, NIPSCO has been faced with a number of major environmental mandates, which have and will continue to result in cost impacts to its customers. The most significant of these recent mandates are the EPAs CCRs rule ("CCR Rule") and MATS. He summarized the Environmental Compliance Projects NIPSCO has implemented leading into NIPSCO's last rate case and the CPCN approved by the Commission in Cause No. 44872, primarily related to compliance with the CCR Rule.

Mr. Carmichael testified about and explained the major environmental statutes and regulations and their impact on NIPSCO's operations. The federal environmental statutes with the most significant economic impact on NIPSCO's operations are the Clean Air Act ("CAA") and its amendments, the Clean Water Act ("CWA"), and the Resource Conservation and Recovery Act ("RCRA"). For the CAA, Mr. Carmichael explained that there are numerous recent and anticipated air regulations that affect, or have the potential to affect, NIPSCO's electric generating units. Over the past few decades, the EPA has set increasingly more stringent National Ambient Air Quality Standards ("NAAQS") for particulate matter, ozone, sulfur dioxide ("SO2"), lead, NOx, and carbon monoxide ("criteria pollutants"). These tighter federal requirements generally translate into federal and state requirements that impose additional environmental controls on emission sources. He explained that NIPSCO has incorporated the expected requirements resulting from the NAAQS into its planning process, including its 2016 and 2018 IRP and that each NIPSCO generating unit is equipped with controls to reduce emissions and therefore ambient concentrations of criteria pollutants.

Mr. Carmichael described the Cross-State Air Pollution Rule ("CSAPR"), an emission allowance trading program that establishes SO2 and NOx emission allowance allocations for each NIPSCO generating unit, which became effective in two phases on January 1, 2015 and January 1, 2017. He also described MATS, which was issued by EPA to reduce mercury, other non-mercury metals, and acid gas emissions from coal- and oil-fired electric generating units, and required compliance at four of NIPSCO's coal units by April 2015. NIPSCO received a one-year compliance extension from the Indiana Department of Environmental Management ("IDEM") for its other three coal units. Mr. Carmichael testified that NIPSCO is in compliance with CSAPR, as its entire coal-fired generation fleet is equipped with flue gas desulfurization ("FGD") controls for SO2 removal. By implementing NIPSCO's MATS compliance projects approved in Cause No. 44311 in 2013, NIPSCO has also achieved compliance with MATS.

Mr. Carmichael also testified about EPA's "Clean Power Plan" that was issued in 2015 under section 111(d) of the CAA and stayed by the U.S. Supreme Court in 2016, but scheduled to be replaced with the Affordable Clean Energy ("ACE") rule. He noted that the specific ramifications of this future rule are not known at this time.

Mr. Carmichael explained that NIPSCO did consider the impacts of regulation of greenhouse gas ("GHG") in its 2018 IRP. He stated that the analysis conducted for NIPSCO's 2018 IRP included various carbon reduction outcomes and timing sensitivities. Paired with a range of carbon costs, NIPSCO considered various alternatives, such as (1) natural gas generators, including natural gas combined cycles, (2) renewable energy options, (3) customer energy efficiency and demand side management, and (4) distributed generation. He testified that the feasibility of the technology or programs, the commercial availability, economic comparisons to other technologies, and compliance with environmental regulations were all taken into account; however, specific ACE Rule scenarios were not included in the IRP because requirements are not known at this time.

Mr. Carmichael further testified about the CWA, which establishes water quality standards for surface waters as well as the basic structure for regulating discharges into the waters of the United States. Under the CWA, the EPA implements pollution control programs such as setting wastewater standards for industry including for electric utilities. The CWA requirements are generally implemented by the National Pollutant Discharge Elimination System ("NPDES") permit program. He explained how CWA regulations impact NIPSCO's operations, including through the Effluent Guidelines and Standards ("ELG Rule"), which was most recently revised on January 4, 2016. The ELG Rule regulates wastewater discharges from power plants that use a fossil fuel to generate electricity and is implemented as the regulatory requirements are incorporated into NPDES permits. He stated that the ELG Rule imposes new wastewater treatment and discharge requirements on NIPSCO's electric generating facilities to be applied between 2018 and 2023. He explained that the requirements of this rule were incorporated into Michigan City's NPDES permit effective April 1, 2016. The ELG Rule itself, though, is under reconsideration by EPA, who anticipates finalizing changes to it in late 2019.

Mr. Carmichael testified about NIPSCO's current compliance with the ELG Rule. Specifically, once certain improvements related to CCR compliance go into service, Schahfer Units 14 and 15 and Michigan City Unit 12 will meet the requirements of the existing ELG Rule for bottom ash transport water. Schahfer Units 14 and 15 operate with a wet FGD system and would likely require significant FGD wastewater upgrades if operated beyond the ELG compliance dates. Michigan City Unit 12 has a dry FGD and thus will meet the requirements of the existing ELG Rule for both FGD wastewater as a result of a dry FGD system and bottom ash transport water as a result of the CCR compliance project. He noted that NIPSCO's preliminary study estimated ELG Rule compliance costs to be approximately $170 million.

Mr. Carmichael next described RCRA, which sets forth a framework for the management of both hazardous and non-hazardous wastes. Under Subtitle D of RCRA, EPA imposed the CCR Rule. The CCR Rule is federally mandated and became effective October 19, 2015, with multiple compliance dates phased in over time. Because it was promulgated under Subtitle D of the RCRA, it was a self-implementing rule when originally promulgated. However, as Mr. Carmichael explained, in 2016 the Water Infrastructure Improvements for the Nation Act amended the CCR Rule and authorized states to submit, to the EPA for approval, a permit program for regulating CCR units in lieu of the CCR Rule. This amendment also allows states to adopt different technical standards from the CCR Rule so long as the standards are at least as protective as the federal rule. In circumstances where a state does not seek approval of a permit program or where EPA denies a state application, the amendments require EPA to adopt a permit program in lieu of the self-implementing rule, provided Congress provides funding for EPA to carry out a permit program. If no permit program is in effect in a state, the CCR Rule remains self-implementing.

Mr. Carmichael also explained that the Indiana Environmental Rules Board adopted a rule incorporating the EPA CCR Rule requirements for CCR surface impoundments into the Indiana Code in 2016 and that IDEM adopted an amendment to Indiana's Solid Waste Management Plan describing IDEM's plan to update Indiana's regulations for regulating CCR disposal facilities to standards equivalent to the U.S. EPA Rule in 2017. This plan enables IDEM to approve and enforce compliance schedules and to extend deadlines in the CCR Rule under certain circumstances and was approved by EPA on March 7, 2017.

Mr. Carmichael testified about where NIPSCO stands with regard to compliance with the CCR Rule's requirements, such as those related to location restrictions, impoundment design criteria, operating criteria, groundwater monitoring and corrective action, closure and post-closure care and recordkeeping, notification, and posting of information to the Internet. He explained that NIPSCO is in the process of executing a set of projects, approved by the Commission in Cause No. 44872, to ensure compliance with the CCR Rule. Ultimately, groundwater monitoring results, location restrictions, future CCR management practices, and beneficial use of CCRs will determine compliance outcomes. He explained that, in the near term, NIPSCO is required to install a groundwater monitoring network, containerize CCR processing areas, address inactive CCR surface impoundments, conduct periodic inspections, and create a publicly accessible recordkeeping and reporting internet site. In addition, NIPSCO is currently reviewing data and will update closure plans and assess corrective measures for IDEM review and approval, as required by the CCR Rule and IDEM. In the meantime, NIPSCO continues to meet the compliance obligation established in the final CCR Rule. He also provided information about the projects for CCR compliance approved in Cause No. 44872, including the related cost estimates.

Mr. Carmichael next discussed the Asset Retirement Obligations and explained that NIPSCO is not proposing to recover these costs through its base rates in this proceeding but that the compliance requirements are mandatory and NIPSCO must expend the necessary funds to ensure compliance. Mr. Carmichael stated that there are certain events that may require CCR surface impoundments to cease operation and close and explained that, based on currently-available groundwater monitoring data, there may be a triggering event that would require NIPSCO to cease placing CCRs into those CCR surface impoundment within six months and initiate closure within 30 days. He testified that the CCR Rule also has an alternative closure provision that allows a CCR surface impoundment to continue to operate if the owner certifies that the facility will permanently cease operation of the boiler and complete closure by October 17, 2023 for a surface impoundment that is 40 acres or smaller, or by October 17, 2028 for a surface impoundment that is greater than 40 acres. He also outlined recent developments to the CCR Rule, including certain litigation and EPA review that is ongoing. He noted that NIPSCO does not anticipate CCR Rule changes resulting from the court decision will impact its current set of projects related to CCR compliance.

Mr. Carmichael also explained that NIPSCO has a total of 13 CCR surface impoundments and 1 CCR Landfill at Bailly, Schahfer, and Michigan City that are subject to the CCR Rule and/or RCRA. He then explained the two closure methods available to NIPSCO under the CCR Rule: (1) closure by removal and (2) closure in place (a.k.a., "capping"). Closure by removal entails dewatering of the free liquids within/on top of the ash, followed by excavation of all ash within the pond limits, including the liner (if one is present). The excavated ash is then properly managed, and the pond can then be backfilled and graded. Closure in place entails the removal of the free liquids within/on top of the pond as well as free liquids in materials placed in the pond (to make a stable base for the engineered capping system). Once the pond is dewatered, the remaining CCRs must be graded, and, in most circumstances, have additional fill materials brought in to provide a suitable base for the cap. The CCRs are then capped with soil, clay, and/or an engineered barrier, then mulched and seeded with a vegetative cover. In addition to the cap, there are some indications that a slurry wall or in-situ stabilization may be required for surface impoundments that have a hydraulic connection to the groundwater and are closed in place. Mr. Carmichael then outlined the number of CCR impoundments and landfills at each NIPSCO generating station and the currently-anticipated method of closure for each, which are based on currently-available information and subject to change based on the effectiveness of its closure activities and collection of further groundwater data. He again noted that NIPSCO is not proposing to recover these federal CCR compliance costs through base rates in this proceeding and that the costs, therefore, have not been included in the Asset Demolition Studies for each generating station sponsored by NIPSCO Witness Ranalletta. As delineated in Mr. Ranalletta's Attachments 12-A, 12-B, and 12-C, federally mandated CCR ARO costs, inclusive of contingency and indirect costs, at Schahfer are expected to be $90.893 million; at Bailly are expected to be $24.736 million; and at Michigan City are expected to be $25.89 million.

Mr. Carmichael outlined some other significant environmental remediation obligations at its generating stations. NIPSCO has some coal ash-related remediation obligations that are not directly tied to the federal CCR Rule at each of its generating stations, which include state requirements under Indiana's Solid Waste Management Program. At Bailly, there are also obligations under the federal RCRA that are related to Solid Waste Management Units based on an order entered into between NIPSCO and EPA in 2005 under RCRA, which required NIPSCO to investigate and, if needed, remediate areas at Bailly that were impacted by historic waste handling. He also discussed an obligation related to asbestos containing material at Bailly, Schahfer, and Michigan City, which are based on both federal and Indiana law.

Mr. Carmichael addressed the interplay between environmental regulation and NIPSCO's resource planning, such as in its IRP. He testified that NIPSCO incorporates the cumulative impact of future environmental requirements in the IRP process and that the IRP considers impacts of anticipated environmental rules and regulations. NIPSCO's IRP considered compliance with all applicable environmental regulations. Notably, the CCR and ELG Rules require significant capital expenditures for compliance. Future anticipated regulation of GHG emissions, as well as updated CSAPR and ozone NAAQS regulation on Schahfer Units 17 and 18, were also specifically considered.

Mr. Carmichael also testified about the key assumptions that were made for environmental regulations that impact the IRP. For the CCR Rule, he stated that NIPSCO is required to incur capital cost for Schahfer Units 14 and 15 and Michigan City Unit 12 of approximately $193 million. Based upon a preliminary study of the November 3, 2015 final ELG Rule, capital costs for ELG compliance were expected to be approximately $170 million for Zero Liquid Discharge control technology on Schahfer Units 14 and 15 and $375 million for Units 17 and 18. Michigan City Unit 12 is equipped with a dry FGD and is therefore not anticipated to require any significant capital expenditure for ELG Rule compliance. CCR-related infrastructure investment will allow Unit 12 to comply with other aspects of the ELG Rule by the November 1, 2018 compliance date established in its NPDES permit. He also testified that no capital expenditure is expected for ELG compliance on Schahfer Units 14, 15, 17, and 18, because, based on preliminary 2018 IRP results, NIPSCO anticipates retiring these by 2023. All of the ELG compliance cost estimates are subject to change by future anticipated regulation. He stated that NIPSCO did consider several possible ELG rulemaking outcomes in the IRP, which include the requirement to install Zero Liquid Discharge ("ZLD") technology or non-ZLD technology, compliance via unit retirement, and extended compliance dates. Regarding GHG reduction, although the timing and magnitude of required reductions are uncertain, it does not appear likely that significant electric sector GHG reductions will be required by regulation or legislation until the year 2026 or later.

Mr. Carmichael testified that, in the IRP modeling, NIPSCO assumed three carbon price scenarios: base, low, and high. The base case assumes a new federal rule or legislative action effective in 2026. The low case assumes a replacement CPP rule with a focus on coal plant efficiency improvements; however, due to the lack of specificity of requirement at present, no direct costs were assumed for these improvements within the IRP. No specific tax or emission cap requirement would be present under such regulations. The high case assumes a stricter new federal rule or legislative action effective by 2026. He explained that price levels are generally consistent with a 50-60% reduction in electric sector carbon dioxide ("CO2") emissions relative to 2005 by the 2030s. In addition, retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures beyond CCR, ELG, and GHG compliance to reduce NOx emissions. He noted that the IRP assumed compliance with updates to CSAPR and ozone regulations that have not yet been proposed, utilizing SCR technology with a capital cost estimate of $448 million.

I. <u>Andrew S. Campbell</u>. Mr. Campbell explained the purpose of MISO and provided an overview of the MISO Resource Adequacy Process. He explained that NIPSCO, as a Load Serving Entity in MISO, is obligated to have sufficient Capacity Resources to cover its forecasted peak demand plus its Planning Reserve Margin Requirements. If NIPSCO does not have sufficient Capacity Resources to cover its forecasted peak demand and Planning Reserve Margin, NIPSCO may acquire additional capacity through bilateral transactions with other Market

Participants or by bidding on capacity in MISO's annual Planning Resource Auction ("PRA"). If NIPSCO has additional capacity, it may sell the additional capacity in MISO's PRA, or through a bilateral transaction with other Market Participants. Mr. Campbell explained that NIPSCO participates in the MISO Energy and Operating Reserve Market (the "MISO Market"), and offers electricity produced and purchases electricity from the MISO Market on a day-ahead and real-time basis. He explained that participating in the MISO Market provides several benefits, including increased reliability. Mr. Campbell also testified about the MISO-related costs incurred by NIPSCO.

Mr. Campbell explained that NIPSCO has two Wholesale Purchase and Sale Agreements for Wind Energy. NIPSCO is crediting any OSS created by its wind purchase power agreements ("PPAs"). He also explained NIPSCO's recovery of costs of 46 MWs of installed capacity and energy purchases made through the Electric Renewable Feed-In Tariff. NIPSCO recovers purchases of energy from eligible renewable resources through its Section 42(a) tracking mechanism, which is filed with its quarterly Fuel Adjustment Clause ("FAC") proceedings in a manner consistent with NIPSCO's treatment of its wind PPA purchases approved by the Commission in Cause No. 43393, and defers the costs of purchases of capacity under the Electric Renewable Feed-In Tariff for recovery through NIPSCO's Resource Adequacy tracker ("RA Tracker").

Mr. Campbell explained NIPSCO's Capacity, including MISO Requirements, Resources, and Cost. He testified that MISO's Resource Adequacy construct ensures adequate capacity. Any proceeds from the sale of excess capacity sold bi-laterally or through MISO's PRA are credited within NIPSCO's RA Tracker. Any excess capacity that is sold, or additional capacity that is purchased by NIPSCO to meet its Resource Adequacy, is recovered in the NIPSCO RA Tracker. Mr. Campbell explained NIPSCO's three existing Demand Response programs (1) an interruptible offering under Rider 775 whereby large industrial customers can sign up to offer interruptible service used for both economic and reliability reasons; (2) a Demand Response Resource offering under Rider 781 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy; and (3) an Emergency Demand Response offering under Rider 782 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy for use only during emergency operations. He testified that under the proposed rates, NIPSCO will continue to offer three Demand Response programs within Rate 831, Rider 881 and Rider 882. He stated that options within NIPSCO's proposed Rate 831 qualify as a LMR under MISO's tariff, and allows NIPSCO to receive Zonal Resource Credits ("ZRCs").

Mr. Campbell described proposed Rate 831 – Industrial Power Service – Large, as follows:

> As proposed, Rate 831 is available to industrial customers currently taking service under Rates 732, 733, and 734. Rate 831 has three (3) tiers of service, (1) Tier 1; Firm Service, (2) Tier 2; Non-Firm Market Price Service, and (3) Tier 3; Non-Firm Third Party Generation Service. Customers must demonstrate or document, to the Company's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction, that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3.

> This information will be utilized to register the curtailable demand as a Load Modifying Resource ("LMR") with MISO. The Customer can choose to procure additional capacity to reduce or eliminate its curtailable obligations as an LMR through the PRA or by purchasing capacity through a third party bilateral agreement.

Mr. Campbell described how NIPSCO will determine a Customer's capacity requirement. He stated that NIPSCO is obligated to have sufficient Capacity Resources to cover its forecasted Coincident Peak demand plus Planning Reserve Margin Requirements with MISO. He explained that by September 30 of each year, the Company will share with each Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand, and the supporting documentation for the values. The Customers will have 30 days to review and dispute these values. NIPSCO will make all reasonable efforts to resolve any such disputes; however, as the MISO Market Participant, the Company is responsible for all forecasted needs and its forecast methodology, which is subject to audit and due diligence by MISO. He indicated the Company will submit the Customer's Resource Adequacy Requirements on November 1 of each year to comply with MISO's Resource Adequacy timeline. He summarized that this process results in Customers taking service under Rate 831 covering their load ratio share of NIPSCO's Resource Adequacy Requirements with MISO.

Mr. Campbell described Tier 1, Tier 2, and Tier 3 service under Rate 831 as follows:

> Tier 1 is a firm service served by NIPSCO's generation and market activity in MISO. The default Contract Demand election is 30,000 kW with an option to elect above or below that amount down to 10,000 kW. Tier 1 service is subject to applicable Riders as identified in Appendix A of the tariff. Tier 1 service will be first through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service.
>
> The Customer's Tier 2 Contract Demand is the Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 Contract Demand election and any Tier 3 Contract Demand election by the Customer. This service is subject to applicable non-production Riders as identified in Appendix A of the tariff (potential components of FMCA and the energy components of the RTO). The Customer will take all Energy under this Tier 2 service at Day-Ahead LMP at the applicable Company Load Zone plus Transmission Charges. Tier 2 service will be second through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service and then Tier 2 service.
>
> Tier 2 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of the Customer's Tier 2 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 2 Contract Demand is non-firm, subject to MISO Curtailment.
>
> The Customer may elect a Tier 3 Contract Demand up to the Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 firm Contract Demand election. To the extent a Customer declines to elect the Tier 3 Contract Demand to which it is entitled under this Rate,

> it must elect to take Tier 2 Contract Demand. If the Customer elects to take any Tier 3 Contract Demand, NIPSCO, as the Market Participant, will register that Customer as an Asset Owner at MISO. Tier 3 service is subject to applicable non-production Riders as identified in Appendix A of the tariff (potential transmission related components of FMCA). Tier 3 service will be third through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service, then Tier 2 service, and finally Tier 3 service.
>
> If, under the MISO Asset Owner framework, a Customer has not arranged for any third party Energy with NIPSCO as the contracting Market Participant, the Customer will take all Energy under this Tier 3 service at market price (LMP at the applicable Company Load Zone (NIPS.NIPS) plus all applicable MISO market settlement charges plus the Transmission Charge within the Rate. The Customer will be responsible for all market settlement charges incurred by either NIPSCO as the Market Participant or the Customer as Asset Owner for any third party Energy or Capacity arrangements including, but not limited to, transmission charges to deliver energy. MISO Market Portal access will be provided as required to carry out MISO Asset Owner functions. All settlements associated with energy offers and demand bids will be passed through to the Customer and will be billed to the Customer on a weekly basis.
>
> Tier 3 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of the Customer's Tier 3 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 3 Contract Demand is non-firm, subject to MISO Curtailment.

Mr. Campbell described the current MISO charge types that will appear on Asset Owner settlement statements, which are subject to any change or revision by MISO.

Mr. Campbell set out the difference between Tier 2 and Tier 3 service under Rate 831 as follows:

> The primary difference between Tier 2 and Tier 3 is the options each Tier provides for the optimization of demand and capacity in the MISO Market. Tier 2 is essentially a market price service for energy and allows for the "firming-up" of capacity through the MISO PRA or will be able to arrange third-party capacity arrangements. Tier 3 increases optionality available for Customers to optimize their demand in MISO. Tier 3 allows the Customer, with NIPSCO acting as the Market Participant, the ability to optimize their demand using available MISO market options. This could include things like procuring all, or a portion, of their expected energy needs in the Day-Ahead Market, entering into third party bilateral energy arrangements (alternative generation), etc. Customers will also be able to procure capacity through the MISO PRA or will be able to arrange third-party capacity arrangements. Tier 2 and Tier 3 are similar in the sense that any demand not covered by a capacity purchase will be registered at MISO as a LMR and subject to MISO Curtailment. Furthermore, Tier 2 and Tier 3 are both market based options that are not backed by Company owned generation resources.

Mr. Campbell stated that customers will be able to move demand between Tier 2 and Tier 3. He explained that as proposed in Rate 831, Customers will have the ability to make quarterly adjustments between Tier 2 and Tier 3. Customers are allowed to have both Tier 2 and Tier 3, Tier 2 only, or Tier 3 only. NIPSCO will register a single LMR for any Tier 2 and Tier 3 demand not covered by a capacity purchase at MISO as a LMR.

He noted that NIPSCO, as the Market Participant at MISO, is ultimately financially responsible for all the associated activity of its retail customers. While Tier 2 and Tier 3 of Rate 831 do allow degrees of market access, customers taking service are still participating through a retail rate and are subject to charges related to the delivery of energy using NIPSCO's transmission system.

Mr. Campbell said that by creating separate CP Nodes, and hence individual settlement statements with MISO, other customers will be insulated from activity of the Tier 3 customers. Furthermore, any additional charges related to the activity of any Tier 3 Customers will be passed on to the appropriate party (i.e. transmission charges associated with any out-of-market activity).

Mr. Campbell stated that while NIPSCO will be liable for Tier 3 customers' decisions in the MISO Market, the proposed tariff creates a direct link that makes the Tier 3 customers wholly responsible for all of the costs associated with their activity in the MISO Market. He explained that the Asset Owner arrangement allows for a clear carve out of the individual customer activity. As such, the Tier 3 customers receive the full benefits and risks associated with activity in the MISO Market.

As to how curtailments will change under proposed Rate 831, Mr. Campbell described that any non-firm demand under Tier 2 and Tier 3 that is not otherwise covered by procured capacity will be registered by NIPSCO as a LMR with MISO. There is no change in the obligations associated with the LMR registrations from today under current Rider 775. Furthermore, Rate 831 is written in a way that if the LMR rules at MISO change, the Tier 2 and Tier 3 customers will be obligated to comply for any non-firm demand.

Mr. Campbell described the curtailment order that NIPSCO will follow. He detailed that ideally, the first set of customers to be curtailed will be Tier 2 and Tier 3 customers since both of these are non-firm unless capacity is arranged otherwise. Second, customers taking service under Rider 876 and Back-up, Maintenance, and Temporary Services under Rate 830 will be curtailed in the event curtailments under Tier 2 and Tier 3 are insufficient. It is possible that service under Rider 876 and Back-up, Maintenance, and Temporary Services under Rate 830 will be curtailed before exhausting curtailments under Tier 2 and Tier 3 depending on the specifics of the curtailment order issued.

As to notice requirements for curtailment, he indicated that the Company will dispatch Customers for MISO curtailments in accordance with the limitations specified under Rate 831 and the Company's General Rules and Regulations.

Mr. Campbell testified that since the start of the MISO Market, none of NIPSCO's customers have been curtailed and that NIPSCO does not anticipate that there is any increased risk of curtailment as a result of the proposed industrial service structure. Unless there is a localized emergency, where the Company can issue curtailments under Rule 13 of its General Rules and

Regulations, curtailments are controlled by MISO and NIPSCO cannot predict the future utilization of curtailments by MISO.

Mr. Campbell indicated that as a result of the new industrial service structure, NIPSCO will alter its participation within the MISO Market. Generally, for Industrial Customers choosing Tier 3 service, NIPSCO will no longer procure energy nor capacity for their Tier 3 loads. However, for Tier 2 Customers, NIPSCO will procure energy from the market on their behalf. That energy will be allocated to the Tier 2 Customers and be priced at the Day-Ahead LMP at the Company's applicable Load Zone. The Company will continue to offer the Energy produced by its generation facilities into the MISO Market, just as it does today. NIPSCO will also continue to purchase the Energy necessary to serve its non-Tier 3 retail customers from the MISO Market on a day-ahead and real-time basis. The new industrial service structure proposed in Rate 831 will simply place the burden of optimizing customer specific loads on customers electing service under non-firm Tier 3. NIPSCO will continue to optimize remaining retail customer load.

As to implementation, Mr. Campbell first noted that an order in this proceeding could result in an implementation date that does not coincide with MISO's Planning Year. He stated that NIPSCO will make reasonable efforts to register interested customers that qualify for Rate 831 service as Asset Owners consistent with MISO's commercial model updates, so that those registrations are available for a day one of the implementation of new rates. He explained that customers with existing LMR registrations will be required to maintain the same level LMR registration (or more) until the start of the next MISO Planning Year unless Replacement Capacity is provided by the Customer. Customers will remain curtailable until firm capacity is procured at which time NIPSCO will transition Customers to the forecasted Coincident Peak demand plus Planning Reserve Margin Requirements method as discussed above to be consistent with the proposed Rate 831. He stated that Tier 3 Customers will also be able to pre-arrange third party / bilateral energy contracts prior to or shortly after an order is issued. Energy contracts do not have any restrictions requiring alignment to MISO's Planning Year; and as such, there is no implementation risk as energy contracts can start and stop in line with the negotiated terms of the contract.

Mr. Campbell provided an overview of the changes proposed in Rider 876 – Back-up and Maintenance Industrial Service Rider. He stated that Rider 876 is only available to customers taking service under Rate 831. He explained that other changes proposed in Rider 876 include the removal of Temporary Service and an updated pricing structure so it is consistent with Rate 831. He indicated that as an alternative to Back-Up and Maintenance Service under this Rider, a Customer can elect to instead cover the risk associated with derates and outages of its Cogeneration System without risk of Curtailment by utilizing Rate 831 Tier 2 or Tier 3 service and procuring capacity through the MISO PRA or via a third party subject to the provisions outlined in Rate 831. He stated that existing Back-Up and Temporary Service provided in current Rider 776 is retained in NIPSCO's new Rate 830 to align to specific customer needs.

He stated that NIPSCO is also proposing to remove the revenues associated with its Rider 876 due to NIPSCO's inability to predict the usage of the Rider by customers. He explained that the proposed changes to the service structure may alter customer's utilization of proposed Rider 876 and that, services are available under Rate 830, but there still is an inability to predict customer activity. He noted that NIPSCO will also pass back any margins resulting from Back up and Maintenance services through the RTO tracker.

Mr. Campbell provided an overview of new Rate 830 – Industrial Power Service – Small. He stated that as proposed, Rate 830 is similar to existing Rate 732 and is available to Industrial Customers taking service at Transmission or Subtransmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. He explained that Rate 830 differs from Rate 732 in that the Customer shall contract for a definite amount of electrical capacity which shall be not less than 10,000 kWs and not exceed 25,000 kWs. He noted that under Rate 732, Customers contracted for a definite amount of electrical capacity that was not less than 15,000 and that existing Rate 732 customers that do not meet the minimum demand threshold are grandfathered into the rate.

He stated that existing Back-up, Maintenance and Temporary services under Rider 776 is retained in Rate 830 to align with Customer specific needs. Customers taking Back-up, Maintenance and Temporary Services under this Rate shall be subject to Curtailments when curtailment of the Company's Customers under Rate 831 is insufficient. He indicated that except for Buy-Through energy under Temporary Service or Back-up Service, this Rate shall be subject to other Riders as identified on Appendix A of the tariff.

Mr. Campbell provided an overview of the changes proposed in Rider 881 – Demand Response Resource Type 1 (DRR 1) – Energy Only. He explained that although Rider 881 is largely an updated version of the existing Rider 781, changes were warranted to better align with proposed Rate 830 and Rate 831. He noted that NIPSCO has removed the Marginal Forgone Retail Rate ("MFRR") provisions within Rider 881 to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. He noted that currently, only one (1) customer is actively participating in existing Rider 781.

He stated that NIPSCO is proposing to remove margins associated with its Rider 781 – Demand Response Resource Type 1 (DRR 1) – Energy Only (proposed Rider 881). He explained that NIPSCO offers the demand response program to allow NIPSCO's industrial customers a means of offering load drop into the MISO Market as a Demand Response Resource. He stated that the margin NIPSCO receives through Rider 881 is meant to compensate NIPSCO for its MFRR during the load drop event making it appropriate to remove these margins from the Revenue Requirement due to NIPSCO's inability to predict the usage by customers. Mr. Campbell noted that changing market dynamics and individual customer operating characteristics could increase or eliminate the activity. Furthermore, the margin received through the Rider is offset by retail sales that occur should customers choose to discontinue usage of the Rider. He noted that the inability of NIPSCO to predict usage under this Rider and the fact that activity under this Rider is essentially a wash between MFRR and retail sales are both valid reasons that support the removal of margin collected through this Rider. Mr. Campbell sponsored Adjustment REV 16-19SS to decrease the Forward Test Year by $3,383,524 to remove all Demand Response Resource margins.

Mr. Campbell provided an overview of the changes proposed in Rider 882 – Emergency Demand Response Resource Type 1 (EDR 1) – Energy Only. He explained that although Rider 882 is largely an updated version of the existing Rider 782, changes were warranted to better align with proposed Rate 830 and Rate 831. He noted that NIPSCO has removed the MFRR provisions within Rider 882 to better align with MISO's treatment of emergency demand response resources and to reduce potential barriers to customer participation. Currently, no customers participate in existing Rider 782.

Mr. Campbell testified that proposed Rate 831 provides two (2) options of curtailable service (1) Tier 2 is "curtailments and/or MISO PRA capacity," and (2) Tier 3 is "curtailments, and/or MISO PRA capacity, and/or third party capacity," both of which allow a customer to procure capacity to reduce or eliminate the curtailable portion of its load. In either circumstance, the load is covered from a MISO Resource Adequacy perspective.

Mr. Campbell explained NIPSCO's change in the RA Adjustment in this proceeding. He noted that NIPSCO is proposing that the charge of $1,500,000 realized through the purchase of capacity and the sale of excess capacity be removed from the Historic Base Year and the Forward Test Year due to the variability of capacity prices in the broader market. Mr. Campbell sponsored Adjustments REV 2-19R and FP 1B-19R to decrease revenue and expense to remove all budgeted capacity purchases from the Forward Test Year.

Mr. Campbell testified regarding NIPSCO's RTO Tracker, including OSS. He explained that OSS occur when NIPSCO's real-time generation resources exceed the real-time native load obligation excluding Rate 831 Tier 2 and Tier 3 activity. The fuel costs associated with making an OSS are passed back to NIPSCO's FAC customers in the form of a fuel credit. He noted that the August 25, 2010 Order in NIPSCO's 2008 electric rate case in Cause No. 43526 (the "43526 Order") found that NIPSCO's MISO non-fuel costs and revenues and OSS sharing should be included in one mechanism designated as the RTO Adjustment. He explained that the MISO charges and credits are included in the RTO Tracker and the basis on which (energy or demand) each is allocated to customers. He stated that the Commission's 44688 Rate Case Order approved recovery of $16,585,108 of MISO non-fuel transmission costs (net of revenues) in base rates, reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO Tracker, and reset the OSS margin credit to base rates to reflect the level of OSS margins included in base rates of $4,741,390. Mr. Campbell testified that in this proceeding, NIPSCO is proposing to fully track MISO non-fuel costs (net of revenues) and recover the costs through the RTO Tracker. He explained that NIPSCO is making this change because Rate 831 Tier 2 and Tier 3 customers will be responsible for various charges and will be paid differently than today. He noted that were NIPSCO to include the charges in base rates, there would be a misalignment unless NIPSCO ran a cost of service study for each charge type, which would be extraordinarily time consuming. Mr. Campbell noted that in this proceeding, NIPSCO is also proposing to reset the OSS margin credit to base rates to zero. He explained that with the retirement of Bailly Units 7 and 8, NIPSCO's opportunities for OSS could be reduced. He noted the retirement aligns NIPSCO's supply side resources with its load obligations in MISO and could result in less of an opportunity for OSS. On the other hand, NIPSCO's new industrial service structure could result in opportunities for additional OSS. He testified that given the uncertainties, when OSS do occur, NIPSCO would pass back 100% of the margins back to customers. Mr. Campbell sponsored Adjustments REV 9E-19R and FP 3B-19R to decrease revenue and expense to remove all OSS revenues and fuel expenses budgeted for capacity purchases from the Forward Test Year. Mr. Campbell testified that in this proceeding, NIPSCO is also proposing that 100% of OSS margins would be credited to the customer. He explained that the credit would be determined annually and incorporated into NIPSCO's semi-annual tracker filing. Mr. Campbell testified that in this proceeding, NIPSCO is also proposing to pass back any margins resulting from back-up and maintenance services through the RTO tracker. Like the OSS margins, the credit would be determined annually and incorporated into NIPSCO's RTO Tracker semi-annual tracker. Finally, NIPSCO is proposing to update the allocation.

Mr. Campbell described and supported the following proposed pro forma adjustments:

- Adjustment REV-8A-19R and FP-2-19R: For a variety of reasons, NIPSCO liquefied less gas in the Historic Base Period (period beginning January 1, 2017 and ending December 31, 2017) as compared to the volumes expected going forward. The 5 year average of actual gas liquefaction was 1,166,142 MCF. NIPSCO believes the 5 year average is an accurate estimate of future liquefaction, compared to the 611,701 MCF that occurred during the Historic Base Period. Because the liquefaction process is a heavy consumer of electricity, the volume of gas liquefied creates variations in inter-company electric revenues and the associated fuel costs. Adjustments REV 8A-19R and FP 2-19R increases the Forward Test Year revenue by $1,272,135 and expense by $313,541 to align the budget with a five year average for gas liquefaction volumes.

J. Susanne M. Taylor. Ms. Taylor provided background on the relationships between NCSC and NIPSCO and supported the O&M expenses associated with the Corporate and Operating services provided by NCSC to NIPSCO, and sponsored adjustments to those expenses for the Historic Base Period, 2018 Budget Period, and the Forward Test Year. Ms. Taylor explained the structure and role of NCSC. She testified NCSC was established to provide centralized services to its affiliates because providing services on a centralized basis enables the affiliates to realize benefits, including use of personnel and equipment, and the availability of personnel with specialized areas of expertise. She stated there are two types of billings made to affiliates, including NIPSCO: (1) contract billing; and (2) convenience billing. Contract billings represent NCSC labor and costs billed to the respective affiliates, and are identified by billing pools. She explained that contract billed charges may be direct-billed (billed directly to a single affiliate or function, including NIPSCO Electric, NIPSCO Gas or NIPSCO Common), or allocated (split between or among several affiliates), depending upon the nature of the expense. She also explained that convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees with each affiliate billed for its proportional share of the payments made in that respective month. NCSC makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate.

Ms. Taylor testified NCSC has executed an individual Service Agreement with each affiliate that is updated from time to time so that all affiliates that receive service from NCSC are subject to the same Service Agreement, and that agreement designates the types of services to be performed and the method of calculating charges. She stated NCSC is not responsible for appropriately assessing the split between costs attributable to NIPSCO's Electric and Gas operations unless the costs are directly billed to NIPSCO Electric or NIPSCO Gas, which NCSC began doing effective January 1, 2009.

Ms. Taylor testified NCSC is regulated by FERC. Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with FERC, NCSC uses a billing pool system to collect costs that are applicable and billable to affiliates, including NIPSCO. Costs are directly charged to a particular affiliate whenever possible, and in cases involving more than one affiliate, the billing pool system details how expenses are allocated among the participating affiliates. Ms. Taylor testified NCSC allocates costs for a particular billing pool in accordance with the bases of allocation filed annually with FERC, and noted that descriptions of each basis of allocation is provided in each service agreement. She explained that NCSC currently updates the statistical data used in the approved allocation bases at least on a semi-annual basis; provides NIPSCO's leadership team the opportunity to review, discuss, and provide feedback prior to publishing the new allocation percentages.

Ms. Taylor testified that system controls are in place to restrict the use of billing pools to companies benefitting from the services being provided. She noted that NIPSCO's Internal Audit group conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing. Ms. Taylor noted that NiSource, including NCSC, underwent a FERC audit, Docket No. FA11-5-000 covering the period January 1, 2009 through December 31, 2010, and issued no adverse comments to NCSC related to its allocation methods. She stated that NCSC continues to use the same allocation methods reviewed and tested during the FERC audit.

Ms. Taylor testified all services are provided at cost, including compensation for use of capital. She stated affiliates have the right to meet with NCSC to review and assess the quality, costs, and/or allocations of the services being provided. The NIPSCO accounting team performs a review of the bill and makes selections to review charge details for reasonableness and accuracy and alert NCSC accounting if they disagree with a charge.

Ms. Taylor testified the NCSC budget development process are consistent with the NIPSCO planning process from a timing and planning standpoint. She explained that the budget process used to develop the Forward Test Year was the 2018 AFP, consisting of a 5 year horizon where the first two years were broken down by month, and the balance was completed on an annual basis. She stated targets for the NCSC functions are grounded in a trailing 12 month historical spend with merit and inflation adjusted for each year thereafter, the 12 month historical spend is also adjusted to account for one-time items, future planned work, or strategic initiatives.

Ms. Taylor also provided details about the processes that drive the derivation and approval of NCSC budgets. She testified in detail about the substance and calculation of the NCSC O&M expenses allocated to NIPSCO Electric (1) in the Historic Base Period of $106,556,125, (2) in the 2018 Budget Period of $108,514,206, and (3) in the Forward Test Year of $98,973,383. She supported Adjustment OM 7-17 to reduce Corporate Incentive Payout expenses in the amount of $2,623,753 to reflect a payout consistent with target levels included in the Forward Test Year, and Adjustment OM 7-19R to reduce NCSC O&M expenses in the amount of $10,129,461 to reflect (1) customer value savings for a decrease of $4,700,000, (2) other ratemaking adjustments for a decrease of $4,732,776 including: LTIP and profit sharing, promotional advertising, and other miscellaneous adjustments that NIPSCO is not seeking to recover, (3) net pension and medical benefit increase of $203,613, (4) 2017 historical actual allocation adjustment between NIPSCO Electric and Gas for a decrease of $741,022, and (5) an NCSC allocation adjustment of $159,276 to reflect updated NCSC semi-annual allocations billed to NIPSCO as of August 1, 2018 and related decrease to NIPSCO Electric.

Ms. Taylor detailed the calculation of the Forward Test Year level of O&M expense, and testified that amount is reasonable and representative of NIPSCO's ongoing cost of providing service. She explained that The Forward Test Year level of O&M expense is justified by the projected needs of NIPSCO to serve its customers.

K. Kimberly K. Cartella. Ms. Cartella testified about the reasonableness and competitiveness of NIPSCO wages and salaries, incentive compensation, and benefits provided to employees. She also testified in support of the pro forma adjustment to test-year expenses relating to incentive compensation. She explained that NiSource has a "total rewards" compensation philosophy that aims to compensate employees competitively in comparison to the utility industry. According to Ms. Cartella, this compensation philosophy enables NIPSCO to meet its obligation to provide safe, reliable, and cost-effective service to its customers and is consistent across the NiSource companies. She further testified that NIPSCO's total rewards program includes (a) market-driven base compensation, (b) market-driven performance adjustments/merits, (c) long- and short-term incentives, (d) profit sharing, and (e) health and welfare benefits.

Ms. Cartella explained that NiSource employs a compensation and benefits consultants to assist in determining employee compensation across the NiSource Operating Companies, including NIPSCO. Mercer LLC assists NiSource in setting competitive salary ranges and evaluating and recommending changes to employee health and welfare benefit plans. Aon Hewitt Associates ("Aon Hewitt") assists NiSource in pension plan and post-retirement medical actuarial analysis, and Alight Solutions assists with administration of pension and health and welfare benefits.

Ms. Cartella discussed the Corporate Incentive Plan for NiSource and NIPSCO and the annual review, or Performance Management Worksheet, process. According to Ms. Cartella, the potential to earn incentive pay is needed for NIPSCO to be effective in recruiting, retaining, and motivating its employees. She also explained the three levels of incentive compensation—trigger, target, and stretch—and that NIPSCO's Forward Test Year is based on a "target" level payout. In Attachments 11-A, 11-B, and 11-C to her testimony, Ms. Cartella provided comparative analyses that demonstrate the reasonableness of NIPSCO's total cash compensation to employees.

Ms. Cartella also testified about the collective bargaining agreements ("CBAs") that are in effect with NIPSCO bargaining units, including how base pay is calculated and the required wage increases under those CBAs. She provided similar information for employees who are not covered by CBAs. In Attachment 11-D, Ms. Cartella provided information about how annual base pay increases at NIPSCO compare to those provided by other employers. She also described the post-retirement benefits other than pensions that NIPSCO provides to its retirees.

Ms. Cartella explained the benefits offered by NIPSCO. These benefits include health and welfare plans, a defined benefit pension plan (for certain employees), a 401(k) savings plan, and paid time off (vacation, holiday and sick pay). She stated that benefits are an important component of any compensation structure and are necessary to ensure NIPSCO is able to attract and retain qualified employees. She also testified about steps NIPSCO has taken to manage its health care costs.

Ms. Cartella testified that NiSource has compared benefits NIPSCO offered to other energy companies and that the results of the most recent study performed by Aon Hewitt demonstrated that the overall, employer-paid value of NIPSCO's benefits plans is 3.1% lower than the average of a comparator group of eleven national utility companies. Finally, she concluded that NIPSCO's benefits are competitive and reasonable as compared with the offerings from other comparable utility companies in the labor market.

L. Victor F. Ranalletta. Mr. Ranalletta testified about the results of studies performed by Burns & McDonnell estimating the cost of demolishing certain NIPSCO electric power generating stations and remediating the station sites (collectively referred to as "demolition cost"). Mr. Ranalletta explained that Burns & McDonnell was engaged by NIPSCO to update the prior studies that were performed for NIPSCO in Cause Nos. 43526 and 44688, and to prepare written reports documenting the results for this Cause. He testified that he supervised and directed the studies, and he personally inspected each of the generating stations for which demolition cost studies were completed. Mr. Ranalletta prepared separate reports for Schahfer (Attachment 12-A), Bailly (Attachment 12-B), Michigan City (Attachment 12-C), and Sugar Creek (Attachment 12-D). He also prepared a demolition cost breakdown for each of the station sites to show what the costs would be like if NIPSCO were to include costs related to the Asset Retirement Obligations.

Mr. Ranalletta described how Burns & McDonnell performed its studies of the demolition cost for NIPSCO's generating units and remediating the sites to industrial condition. Burns & McDonnell first determined the quantities of concrete, structural steel, equipment, electric cable and raceway, conveyors, tanks, and piping that would need to be removed. Burns & McDonnell based the industrial demolition cost estimates on demolishing each plant down to the surrounding grade elevation. Burns & McDonnell assumed all equipment and material located above and below grade would be dismantled and either sent to a landfill or sold as salvage in the case of steel and copper. The estimate also assumed all below-grade foundations would remain and the below-grade excavated areas would be used for landfill space for the demolished plant concrete. Mr. Ranalletta testified that Burns & McDonnell did not apply any escalation factor beyond January 2018 to the demolition cost estimates; rather (unless noted otherwise) all of the estimates are in January 2018 dollars. He testified Burns & McDonnell carefully prepared the demolition cost estimates using standard and accepted estimating techniques and the best information available, are consistent with other available data and industry experience, and that the assumptions listed in each report are reasonable and the estimates are accurate within the estimating accuracy based on the assumptions made. The demolition cost prepared by Burns & McDonnell includes environmental remediation, as well as indirect costs, contingency, and positive salvage value. The total net cost to demolish each station, net of positive salvage and excluding costs related to the Asset Retirement Obligations, as estimated by Burns & McDonnell is as follows:

Station	Industrial Condition
Schahfer	$85,070,000
Bailly	$40,643,000
Michigan City	$41,519,000

Sugar Creek	$3,490,000

M. John J. Spanos. Mr. Spanos testified about the depreciation analysis he performed related to NIPSCO's electric plant as of December 31, 2017, and his recommendation of depreciation rates for its forecasted electric and common plant in service as of December 31, 2019. He explained the methods and procedures used in the depreciation study and sponsored Attachment 13-B setting forth the results of that study (the "Depreciation Study"), Attachment 13-C setting forth the results of his depreciation analysis related to NIPSCO's projected electric and common plant in service as of December 31, 2019, and Attachment 13-D setting forth alternative depreciation rates and expense as of December 31, 2017 and December 31, 2019.

Mr. Spanos testified about the principal conclusions of his study and the bases for them. He testified that the proposed depreciation accrual rates by account are based on his review of historical data, NIPSCO's operating maintenance practices, and the application of informed engineering judgment. He testified that in preparing the depreciation study, he followed generally accepted practices in the field of depreciation and valuation.

Mr. Spanos testified that he used the straight line remaining life method of depreciation, with the equal life group procedure. He explained 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 method. His recommended annual depreciation accrual rates as of December 31, 2017 for NIPSCO's electric plant and common plant are set forth in the Depreciation Study.

Mr. Spanos testified that he determined the recommended annual depreciation accrual rates in two phases. In the first phase, he estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Regarding the first phase, the service life and net salvage studies consisted of compiling historic data from records related to NIPSCO's plant; analyzing this data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to determine average service life and net salvage characteristics. The historic data analyzed by Mr. Spanos for the purpose of estimating service life characteristics consisted of the Company's accounting entries that record plant transactions during the 82-year period from 1936 through 2017. The transactions analyzed included additions, retirements, transfers and the related balances. The Company records analyzed also included surviving dollar value by year installed for each plant account as of December 31, 2017. Mr. Spanos used the retirement rate method for all electric and common accounts for NIPSCO, to analyze this service life data. He testified that this is the most appropriate method when aged retirement data are available because this method determines the average rates of retirement actually experienced by the Company during the period covered by the study. In order to estimate the lives of significant facilities such as production plants, Mr. Spanos testified that he used the life span technique. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates. He noted that this approach – the life span technique – has been presented to and accepted by many public utility commissions across the United States and Canada, including the Indiana Commission. Mr. Spanos testified that the bases for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. He further testified that he conducted field reviews of a representative portion of the Company's property in July 2015, and that he had previously conducted field reviews in March 2008.

Mr. Spanos testified that he estimated the net salvage percentages based on judgment. He explained that, in doing so, for most accounts, he incorporated analyses of the historical data for the period 1984 through 2017 for electric plant and considered estimates for other electric companies. He also testified that he factored in final net salvage in his recommended net salvage percentages. He noted that the final net salvage or dismantling cost of steam and other production units were based on the 2018 asset demolition studies performed by Burns & McDonnell.

Mr. Spanos explained that he assigned sufficient depreciation reserve to the Bailly Units 7 and 8 to account for the level of recovery to be fully accrued for these units by December 31, 2019. As a result, no future depreciation expense beyond December 31, 2019 will be assigned to these units.

Regarding the second phase of the depreciation study, in which he calculated the composite remaining lives and annual depreciation accrual rates, Mr. Spanos testified as to the following steps. After he estimated the service life and net salvage characteristics for each depreciable property group, he calculated the annual depreciation accrual rates for each group based on the straight line remaining life method using remaining lives weighted consistent with the equal life group procedure. The annual depreciation accrual rates were developed at December 31, 2017. He explained that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life. He further explained that the equal life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals. Mr. Spanos testified that amortization accounting was applied to accounts with a large number of units but with small asset values. He noted that amortization accounting was approved in the 43526 Order and continued in the 44688 Rate Case Order as being appropriate for certain common and general plant accounts, which represents slightly more than 1% of depreciable plant.

Mr. Spanos explained his calculation of the forecasted depreciation rates as of December 31, 2019. First, the plant in service and book reserve were brought forward from December 31, 2017 to December 31, 2019 based on the capital budget by account and by year. The book reserve by account as of December 31, 2019 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, 2019 was developed by vintage within account and the book reserve is developed by account, then the December 31, 2019 depreciation rates were calculated using the same methods and procedures as in the 2017 Depreciation Study. He noted that annual depreciation accrual rates for steam assets at Michigan City and Schahfer are based on the recovery period of December 31, 2030, which is after the retirement date by 2 and 7 years, respectively.

Mr. Spanos also calculated alternative December 31, 2017 and December 31, 2019 depreciation rates (set forth in Attachment 13-D) because the steam assets at Michigan City and Schahfer are to be retired by December 2028 and December 2023, respectively. The alternative depreciation rates represent recovery of the full-service value of these assets (including costs related to certain asset retirement obligations that must be performed in compliance with the federal Coal Combustion Residuals rule) by the date of retirement which is prior to the Depreciation Study calculations.

N. Michael D. McCuen. Mr. McCuen testified about and supported NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income taxes between the Historic Base Period and pro-forma results based on current rates included in the cost of service shown in Ms. Shikany's accounting exhibits. He also presented and supported NIPSCO's Accumulated Deferred Income Taxes and Post 1970 Investment Tax Credit ("ITC") balances and related pro forma adjustments included as components of NIPSCO's Capital Structure. He explained that the income tax calculations were made under the provisions of the Internal Revenue Code of 1986, as amended, and the Indiana Administrative Code. He stated that the federal tax rate in effect for the Historic Base Period was 35% and that the pro-forma test period reflects a 21% federal tax rate in effect starting January 1, 2018. Mr. McCuen testified that he quantified the federal income tax expense beginning with the application of the federal income tax rate applied to pro forma NOI before income taxes less interest expense. He then adjusted this amount to account for: (i) differences between the use of accelerated appreciation for income tax return purposes and straight-line depreciation in determining tax expense for book purposes, and AFUDC; (ii) various tax rate changes including the most recent TCJA; (iii) certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense; (iv) reduction in tax expense for Amortization of ITC; and (v) reduction in tax expense for allocation of parent company (NiSource) interest expense.

For state income tax expense, Mr. McCuen testified that the tax calculations include Indiana Adjusted Gross Income taxes calculated at 5.625%, adjusted for the following four reconciling items: (i) the non-deductibility of the Indiana Utility Receipts Tax; (ii) the excess deferred taxes resulting from the decrease in the state tax rate from 8.5% to 5.625%; (iii) the non-deductibility of certain expenses; and (iv) AFUDC.

Mr. McCuen explained the Company's proposal to reflect $26,870,010 in real and personal property taxes and explained in detail the calculation of and basis for Adjustment OTX-1 that resulted in a pro forma adjusted property tax expense of $26,870,010 for the Forward Test Year. He stated these pro forma property tax adjustments are required to account for planned property additions between the Historic Base Period and Forward Test Year.

Mr. McCuen explained the Company's proposal to reflect no URT in base rates and explained Adjustment OTX-4 that resulted in pro forma adjusted URT of $0 for the Forward Test Year. He explained that NIPSCO is subject to a 1.4% URT on all receipts, except sales for resale and sales to federal government agencies. The URT is calculated then grossed-up and accounted for in the revenue requirement. He explained that NIPSCO proposes to separately state URT as a line item on customer bills, thereby eliminating the gross-up. He testified that the estimated benefit to NIPSCO's customers in this filing is approximately $500,000.

Mr. McCuen also explained the Company's proposal to reflect $55,856,537 in federal and state income taxes and explained Adjustments ITX 1-19R in the amount of $87,484,708, ITX 1-19SS in the amount of $131,669, and PF4 in the amount of $28,247,441. He explained the federal and state income taxes for the Historic Base Period per books was $114,962,135. The three adjustments were made to the Historic Base Period to: (i) decrease to federal and state income taxes to reflect tax expense on pro forma taxable income at current rates; (ii) increase to tax expense due to the changes in the proposed service structure at current rates; and (iii) increase to total federal and state income tax due to the increase in proposed revenue requirement.

Finally, Mr. McCuen also explained adjustments to NIPSCO's capital structure. He explained Adjustments CS 4-18 in the amount of $71,828,337 and CS 4-19 in the amount of $44,252,216 increase Deferred Income Taxes for the period ending December 31, 2018 and December 31, 2019. He stated the deferred income tax balances are forecasted by using a combination of pre-tax income and changes in balance sheet accounts. NIPSCO utilizes Accounting Standards Codification 740 and 980 to account for income taxes in order to reflect its after-tax financial position in its balance sheet. He explained that Adjustments CS 7-18 in the amount of $259,068 and CS 7-19 in the amount of $656,208 decrease Post 1970-ITC for the period ending December 31, 2018 and December 31, 2019. He stated the Post 1970-ITC balances are forecasted by amortizing the remaining balance over the service life of the property that generated the credits, and testified that the tax expense adjustments reflected in Ms. Shikany's accounting exhibits were correct and consistent with his description of the applicable tax provisions.

O. Vincent V. Rea. Mr. Rea testified about the appropriate rate of return on common equity and overall rate of return that the Commission should establish for NIPSCO's vertically-integrated electric utility operations in relation to its revenue requirement calculation. He also addressed the appropriate ratemaking capital structure, WACC and embedded cost of debt. Based on his evaluation, he concluded that the cost of common equity for NIPSCO's jurisdictional electric utility operations is in the range of 10.55 to 11.05 percent, and that a point estimate at the midpoint of this range, or 10.80 percent, is the appropriate cost of equity to apply in this case. Based upon this finding, he determined that the Company's WACC is 7.02 percent**,** which is based on NIPSCO's forward test-year-end regulatory capital structure as of December 31, 2019. This resulting overall cost of capital, if adopted by the Commission, will allow NIPSCO to earn the prevailing opportunity cost of capital, maintain its financial integrity, and attract capital at reasonable terms. Mr. Rea also presented the capital structure and WACC as of December 31, 2019.

Mr. Rea explained the general approach taken in determining the cost of common equity, and supported it with a detailed explanation of the analytical models used and their specific application for this case. He stated that he analyzed market-derived data and other financial information for 18 companies comprising two separate proxy groups. He explained that during the course of his evaluation, he applied three (3) well-recognized analytical models to the market and financial data of the selected proxy group companies: the Discounted Cash Flow model, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium Method ("RPM"). He also evaluated two other model variants of the CAPM, specifically, the CAPM with size adjustment, and the Empirical CAPM, both of which have been validated by empirical research. Finally, to confirm the reasonableness of the cost of equity estimates yielded by the aforementioned market-based models, he also reviewed the earned returns of non-rate-regulated companies having comparable risks by completing a Comparable Earnings Approach analysis. Mr. Rea developed his cost of equity recommendations after carefully evaluating the individual cost of equity estimates that were derived from applying the various analytical models to the market and financial data of the proxy group companies. Using a variety of analytical models in conjunction with multiple comparable risk proxy groups ensures that a diversity of investor perspectives are incorporated into the cost of capital evaluation, thus providing a solid foundation upon which the analyst can apply his/her informed judgment in making a cost of equity recommendation.

Mr. Rea testified the Company is proposing that its Forward Test Year capital structure, as of December 31, 2019, be employed for rate-setting purposes. His specific recommendations were presented in Schedule 2, detailing NIPSCO's projected capitalization levels, corresponding capital structure ratios, and embedded cost of debt as of December 31, 2019. He stated that to confirm the reasonableness of the Company's Forward Test Year capital structure, he evaluated the actual and projected equity capitalization levels for the Electric Utility Group companies, as published by Value Line, which are calculated on the basis of permanent capitalization, and therefore exclude short-term debt. He stated the Company's proposed equity capitalization level, based upon investor-supplied sources of capital, as of December 31, 2019, is 57.11 percent, which is within the range of equity capitalization ratios anticipated for the Electric Utility Group companies, as reflected in near-term forecasts published by Value Line. Mr. Rea testified the cost rate for common equity is 10.80 percent, which is the cost of equity he is recommending in this proceeding and the cost rate for Long-Term Debt is 4.97 percent, which is based on the Company's projected long-term debt outstanding at December 31, 2019.

P. Paula Strauss. Ms. Strauss explained how the Historic Test Period kWh consumption was adjusted to reflect the kWh consumption under normal weather conditions, the base load temperature-sensitive load normalization procedure, and the forecast method used to derive the Forward Test Year customer counts and volume and to propose an adjustment to align the forecast with the definition of normal weather proposed for ratemaking purposes. She testified that NIPSCO used the base load/temperature-sensitive load normalization procedure approved by the Commission in its 44688 Rate Case Order using three sources of data in its analysis: (1) monthly billing data from its actual billing records, (2) NOAA National Weather Service Weather Stations data for actual temperatures used to calculate Cooling Degree Days ("CDD"), and (3) the 30-year average of temperature data from 1988-2017 using NOAA's National Weather Service temperatures. She explained that NIPSCO has updated its definition of normal weather as the 30-year average ending in 2017, which is an update to the normal CDDs calculated by NOAA's National Weather Service, which uses data for the 30-year period ended 2010, using data from Valparaiso, South Bend and Fort Wayne weighted by the number of residential customers assigned to those stations to represent the NIPSCO service territory.

Ms. Strauss testified that with actual CDD lower than normal by 6%, the Historic Test Period was cooler than normal, and usage for the adjusted rates was adjusted up by 0.8% to reflect normal weather which were used by NIPSCO Witness Westerhausen to calculate pro-forma expense and revenue levels. She explained in detail how kWh usage varied with CDD and explained that in her opinion the data supported the result reached in her study because of the strong correlation between CDD and kWh during the period 2008 through 2017. She concluded that the net result of her analysis was that Historic Test Period volumes should be increased by 59,151,141 kWh to reflect normal weather as reflected in Attachment 16-A to her testimony.

Ms. Strauss explained that customer and energy projections utilized in NIPSCO's budget are developed by NIPSCO's Forecasting Group using projections of residential and commercial new customer additions provided by the New Business department, budget projections for large industrial customers provided by the Major Accounts department, and an outlook for all other small industrial customers utilized in the budget is provided by the Financial Planning department. She testified that the Forecasting Group uses average saturation and efficiency data, economic variables and deflator information, and weather data is obtained from external consulting services when estimating the Forward Test Year level of usage. Ms. Strauss provided descriptions of the derivation process used to develop each input into the forecast used to develop NIPSCO's budget. She explained that the forecast was provided to Mr. Westerhausen as reflected in Attachment 16-B to her testimony, and noted that forecasts are updated annually with the most current data. She explained that internal reviews of the forecast performance occurs on a regular basis and that variances are calculated and assessed in order to measure accuracy. She testified that for the last five years, the average annual one year weather normalized variance for the residential model is 1.8%, for the commercial model it is 1.5%, and for the more volatile industrial model the forecast average variance was 3.8%.

Q. Bickey Rimal. Mr. Rimal testified in support of the ACOSS used in conducting NIPSCO's electric cost of service study. Mr. Rimal supported the various special studies that were utilized within the ACOSS to apportion the various categories of plant and O&M expenses to the respective customer classes. Some of these special studies include the Functional Split Study, which consists of analyses that provide the functional split for costs relating to the Sub-transmission, Railroad, Primary, and Secondary functions. He also supported a minimum system study to separately classify certain distribution costs as demand-related and customer-related. He also provided the basis for several studies including the asset allocation study which allows for the appropriate assignment of assets to different rate classes, and the methodology of the Transformer; Services; and Meters Asset Allocation Analysis. Mr. Rimal described the general need for, and methodology of, the special studies, including how these studies were conducted for NIPSCO's ACOSS. He stated that there were two main sources of the data and inputs utilized within the studies: (a) the historical books and records of NIPSCO including the general ledger and engineering systems; and (b) interviews with relevant NIPSCO personnel. Mr. Rimal also supported a fixed variable analysis to determine the proportion of NIPSCO's production O&M that varies with energy consumption. Mr. Rimal also provided basis for allocating certain customer accounts expenses to the various rate classes by conducting Operating Expense Allocation Study.

R. J. Stephen Gaske. Dr. Gaske testified that NIPSCO requested that Concentric conduct a fully-allocated cost of service study to determine the embedded costs of serving its various electric retail customers, and design rates that would be reasonable and appropriate for recovering the test year revenue requirements from the various customers. Dr. Gaske sponsored the class cost of service study and rate design filed in this proceeding. He stated that the restructured industrial rate and service offerings are reflected in the ACOSS model.

Dr. Gaske discussed the purpose of an ACOSS and described the Concentric Cost of Service Model used in conducting NIPSCO's electric cost of service study. Dr. Gaske testified that the purpose of the ACOSS is to allocate NIPSCO's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Dr. Gaske further discussed various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in the Company's electric cost of service studies. He noted that Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs are largely a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, line transformers, services, meters, and customer billing and accounting expenses.

Dr. Gaske and Mr. Rimal also described the relative cost studies and other analyses employed to apportion the various categories of plant and O&M expenses to the respective customer classes. Dr. Gaske further explained that Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, larger transformers and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. He also explained that Energy Costs are those costs that vary with the amount of kWhs sold to customers. For example, included in the instant study are base fuel rates as well as some production operating costs that tend to vary with the amount of energy produced. However, except for fuel the vast majority of NIPSCO's costs are fixed with respect to energy usage and very little of its remaining delivery service cost structure is energy related.

Dr. Gaske sponsored attachments and workpapers that showed how NIPSCO's costs were functionalized, classified and then allocated to the various rate classes. Dr. Gaske discussed the coincident peaks during the four summer months of the test period ("4CP"), June through September, were used to allocate the demand-related costs associated with the production functions. However, the 4CP demands of the new Rate 831 industrial classes were reduced to reflect the revised firm contract demands that these customers will place on the NIPSCO generating station after their services are restructured. The coincident peak demands that customers placed on the transmission system during each of the twelve months of the test period ("12CP") were utilized to allocate demand-related costs associated with the transmission functions. However, the 12CP demands used in the transmission cost allocation reflect a reduction to the Rate 831 demand to account for the proposed discount for Adjacent Qualifying Facility short-haul transmission service. Dr. Gaske explained that he reviewed the system peaks for all months during the 2010 – 2017 period and applied FERC's cost allocation tests to NIPSCO's load characteristics. Those tests indicated that either a 4CP or a 12CP methodology would be appropriate for the production function. Dr. Gaske noted that after reviewing several years of data, there were ambiguous results for the FERC tests for using a 12CP allocator. He explained that the 2017 results failed one of the FERC tests and 2016 failed two of the three tests. Dr. Gaske further noted that during the past eight years, the months of June – September were almost always within 90% of the annual peak, but none of the other eight months were ever within 90% of the annual peak. Thus, it is appropriate to use a 4CP allocator for NIPSCO's demand-related production costs in this proceeding. Dr. Gaske noted that other adjustments to the test period demand and energy determinants were made. He explained that the generation kWh and 4CP demand allocators used to allocate production costs to these customers (Rate 831) was adjusted to reflect the customers' new generation contract demand and energy use rather than their historical demands. He testified that the 12CP and NCP demand allocators continue to reflect the actual demands that each class places on the transmission and distribution system with one exception – one large customer decided to recategorize an exempt wholesale generation facility that is owned by an affiliate as behind-the-meter cogeneration. To address this issue and similar possibilities, NIPSCO is offering an alternative transmission charge solely to commonly-owned or affiliated customers that are located on adjacent premises that have cogeneration facilities that can produce power at one premise and transfer that power to its adjacent premise. He stated that because such customers will need to use only a small portion of the NIPSCO transmission system to transmit power from one of its facilities to an adjacent industrial facility, and because some contribution to fixed cost is better than none, NIPSCO is proposing to provide a 70 percent discount on the transmission charge for power that is transmitted between two premises that satisfy the requirements. He testified the 12CP value used to allocate transmission costs has been adjusted to reflect such a discount for these situations.

Dr. Gaske provided a class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for: (i) the 700 series rate classes that were forecasted to be in effect during the test year, and (ii) the 800 series rate classes that are being proposed in this rate filing, which included the resulting unit costs by class for customer, demand and energy-related costs within the ACOSS. Dr. Gaske also described the method used to apportion the Company's revenue deficiency to the various rate schedules. Specifically, he described the principles and methods used to mitigate the impacts on those classes that would receive larger rate increases if the unmitigated results of the ACOSS were to be used to set rates in this proceeding.

Dr. Gaske testified that the Company used the results of the ACOSS as a first step in deciding the class revenue responsibility. He explained the ACOSS results were then adjusted to mitigate the largest rate increases. Specifically, because of residential class subsidies that were retained in prior rate proceedings, and because of the combination of industrial service restructuring and other cost increases, the ACOSS indicated that residential customers would require a rate increase in excess of 30 percent. He stated that in order to mitigate this impact, it was determined that all classes except the large industrial (Rate 831) should receive the same across-the-board percentage rate increase. He indicated that rates for the large industrial class would then be based on the allocated cost of service.

Dr. Gaske described the process and showed the calculations used to design the rates that are being proposed in this proceeding. For the new classes, proposed Rate 830 would be a two-part rate consisting of a demand charge and a flat energy charge and proposed Rate 831 for partial-requirements industrial customers will consist of a demand charge based on the customer's firm contract demand for NIPSCO generation, a transmission charge per kWh of energy it has delivered regardless of generation source, and an energy charge per kWh for energy that is purchased from NIPSCO. He noted that there also is an Adjacent Premise Qualifying Facility discounted transmission rate available. The rate designs for the other classes would remain unchanged.

Dr. Gaske discussed the impact of NIPSCO's proposed removal of the Interruptible Rider (Rider 775). As a result of the restructuring of industrial service offerings, there will no longer be any industrial customer loads taking interruptible service. He stated that projected revenue at current rates includes approximately $52 million in Rider 775 interruptible credits for industrial customers that would be allocated for recovery from all customers but that the industrial restructuring will eliminate those credits and recovery amounts. As a result of the revisions to NIPSCO's Backup, Maintenance and Temporary Services available under Rider 776, he noted that the existing Back-up and Maintenance services under Rider 776 are retained for Rate 830 and Rate 831 customers, and Temporary services are retained for Rate 830 customers. He stated that because of the restructuring of service for the 831 customers who will begin managing much of their own generation needs, Temporary service will no longer be available to customers that migrate to that rate schedule. He explained that the rate for Backup service will continue to be the applicable demand charge divided by the number of days in the month, plus an energy charge equal to the real-time LMP and the non-fuel energy charge. The current daily demand charges for Maintenance service will be increased by the proposed system-wide percentage increase in margin, and the energy and transmission charges for that service would be the energy and transmission charges for the applicable rate schedule. Finally, no change to the existing daily demand charges for Temporary service is being proposed. He stated that because the revenues associated with the proposed Rider 876 are expected to be small and inherently unpredictable, NIPSCO has not included a credit for these revenues in designing the base rates. Instead, any margin revenue collected under Rider 876 will be flowed through the RTO rider (Rider 871) as a credit on customers' bills.

Dr. Gaske concluded by discussing the customer impacts of the proposed rates. Dr. Gaske determined that the proposed rate levels and structure establish rates that are just, reasonable, and not unreasonably preferential or discriminatory. Dr. Gaske opined that the proposed rate structure and rates should provide NIPSCO a reasonable opportunity to earn a reasonable return on its invested capital and recover its necessary and reasonable operating expenses.

S. Curt A. Westerhausen. Mr. Westerhausen stated that NIPSCO had three overall policy objectives in the development of the rates proposed in this proceeding: (1) restructure the industrial rate classes to accommodate the large industrial customers that want to reduce their dependence on NIPSCO generation; (2) moderate rate shock for the other rate classes; and (3) ensure that rate design calculations are simple and transparent.

Mr. Westerhausen described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 14, including the Schedule of Rates, Riders and General Rules and Regulations and explained how the proposed tariff differs from NIPSCO's currently effective IURC Electric

Service Tariff, Original Volume No. 13. He explained that the service structure would remain the same for residential and commercial customers, except for a proposed increase in fixed recovery by increasing customer charges. He noted that NIPSCO is proposing a new industrial service structure and proposing to discontinue its ECR Mechanism and Interruptible Industrial Service (Rider 775). He noted that the current rates have been updated to reflect NIPSCO's proposed revenue requirement allocated to the rate classes through the ACOSS and mitigation model.

In describing NIPSCO's new industrial service structure, he explained that NIPSCO is proposing new Rates 830 and 831 to replace current Rate 732 (Industrial Power Service), Rate 733 (High Load Factor Industrial Power Service), and Rate 734 (Industrial Power Service for Air Separation & Hydrogen Production Market Customers) utilized by NIPSCO's largest industrial customers. He stated that under the new rate structure in Rate 831, there is no longer a need for the interruptible Rider 775 which the Company is proposing to eliminate. He also stated that Back-up and Maintenance Service is available to Rate 831 customers under revised Rider 876 and Back-up and Maintenance Service is built into the rate structure under Rate 830. He noted that Riders 881 and 882 are still available to these customers with minimal changes.

Mr. Westerhausen stated that NIPSCO's current ECR Mechanism is applicable to all Rates and is filed semi-annually to recover Environmental Compliance Projects, as authorized by the Commission. He explained that since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECR Mechanism, which will have no significant change in timing for NIPSCO or customers and relieves NIPSCO and its stakeholders of the ECR semi-annual tracker filing.

Mr. Westerhausen stated that NIPSCO discontinued its Residential spaceheating rates (Rate 611 Spaceheating and Rates 612 and 613) in their entirety in the 44688 Rate Case. He explained that at that time, NIPSCO anticipated discontinuing its Commercial spaceheating rate (Rates 720 and 722) in this proceeding; however, because of the additional complexity of discontinuing those rates, NIPSCO is not proposing any changes in this proceeding.

Mr. Westerhausen summarized each of NIPSCO's Proposed Rates including a discussion of the components of each rate and an overview of the changes made to each and the rationale for making them.

Mr. Westerhausen summarized NIPSCO's Proposed Rates. He testified that other than updated billing rates, Rates 820, 821, 822, 823, 824, 825, 826, 841, 842, 844, 855, 860, and 865, continue substantially unchanged. He described the material changes to the other Proposed Rates as follows:

Rate 811 – Rate for Electric Service, Residential (RS)

Rate 811 is available to Residential and farm Customers. This rate consists of a Customer Charge, an Energy Charge and applicable Riders. Other than updated billing rates, Rate 811 continues substantially unchanged.

Rate 830 – Rate for Electric Service, Industrial Power Service – Small

Rate 830 is available to Industrial Customers taking service at Transmission or Subtransmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. The Customer shall contract for a definite amount of electrical capacity which shall be more than 10,000 kWs and not exceed 25,000 kWs. Those Premises being served under Rate 732 or 733 on October 31, 2018 that satisfy the maximum capacity limitation may elect to be grandfathered into this rate.

Customers taking Back-up, Maintenance and Temporary Services under this rate shall be subject to Curtailments when curtailment of the Company's Customers under Rate 831 is insufficient. This rate consists of a Demand Charge, an Energy Charge and applicable Riders (except for Buy-Through Energy under Temporary Service or Back-up Service). This rate is further discussed by NIPSCO Witnesses Campbell and Kelly.

Rate 831 – Rate for Electric Service, Industrial Power Service – Large

Rate 831 is available to Industrial Customers taking service at Transmission or Subtransmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. Customer shall contract for a definite amount of electrical demand which shall not be less than 10,000 kWs for a five-year term. Rate 831 has three (3) tiers of service, (1) Tier 1; Firm Service, (2) Tier 2; Non-Firm Market Price Service, and (3) Tier 3; Non-Firm Third Party Generation Service. Customers must demonstrate or document, to the Company's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction, that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3. This rate consists of a Demand Charge (Tier 1), an Energy Charge (Tier 1), a Transmission Charge (Tier 1, Tier 2, and Tier 3), an Adjacent Affiliate Qualifying Facility Premise Transmission Charge (Tier 1, Tier 2, and Tier 3), and applicable Riders. This rate is further discussed by NIPSCO Witnesses Campbell and Kelly.

Rate 850 – Rate for Electric Service, Street Lighting (SL)

Rate 850 is available for street, highway and billboard lighting service to Customers for lighting systems located on electric supply lines of the Company. Billing is based upon type, ownership and responsible maintaining party of the lighting fixture. This rate is comprised of a Lamp Charge, an Energy Charge and applicable Riders. Other than updated billing rates, Rate 850 continues substantially unchanged.

While NIPSCO is not proposing any changes to the structure of this rate, communities that are currently receiving subsidies from NIPSCO's TDSIC rates will stop receiving those subsidies once NIPSCO's new base rates are approved. In this proceeding, NIPSCO is proposing to roll the Electric TDSIC tracker rate base as of December 31, 2019 into the revenue requirement. Because of this, NIPSCO is proposing that all customers served under the TDSIC program as of December 31, 2019 will move to its standard street lighting program. For those customers that have LED street lighting TDSIC replacement installations completed on or after January 1, 2020,[33] NIPSCO is not proposing any changes. That is, they would be charged under the proposed TDSIC installed LED rates.

Mr. Westerhausen summarized NIPSCO's Proposed Riders. He testified that Riders 877, 878, 879, 880, 883, 886, 887, and 888 continue substantially unchanged.[34] He described the changes to the other Proposed Riders as follows:

Rider 870 – Adjustment of Charges for Cost of Fuel Rider (FAC)

Rider 870 has been updated with the average cost of fuel in base rates in this proceeding. The test year fuel costs were included in the Allocated Cost of Service Study model and allocated by energy at the generator. This is further discussed by NIPSCO Witness Gaske. Due to the elimination of Rider 775, 25% of costs associated with credits paid for interruptible and / or curtailable load under Rider 775 will no longer be passed through this Rider. NIPSCO is also proposing to separately state the Utilities Receipts Tax on customer bills instead of including it in the calculation of the factors in this Rider. This is further discussed by NIPSCO Witnesses Shikany and McCuen. The Fuel Cost Charge is shown in Appendix B.

Rider 871 – Adjustment of Charges for Regional Transmission Organization (RTO)

Rider 871 is a semi-annual mechanism to recover net non-fuel MISO costs and revenues above and below $16,585,108 on an annual basis and 50% sharing of off-system sales margins over and under $4,741,390 on an annual basis. In this proceeding, NIPSCO is proposing to fully track MISO non-fuel costs (net of revenues) and recover the costs through the RTO. NIPSCO is also proposing to reset the off-system sales and back-up and maintenance margin credits in base rates to zero and credit 100% of margins annually. This is further discussed by NIPSCO Witness Campbell. NIPSCO is also proposing to separately state the Utilities Receipts Tax on customer bills instead of including it in the calculation of the factors in this Rider. This is further discussed by NIPSCO Witnesses Shikany and McCuen. The production and energy allocators utilized for purposes of allocating the costs inside of this Rider will be updated based upon the Allocated Cost of Service Study. The RTO Adjustment Factors are shown in Appendix C.

Rider 874 – Adjustment of Charges for Resource Adequacy (RA)

Rider 874 is a semi-annual mechanism to recover the cost of capacity purchases and sales and 75% of costs associated with credits paid for interruptible load. Due to the elimination of Rider 775, 75% of costs associated with credits paid for interruptible load under Rider 775 will no longer be passed through this Rider. NIPSCO is also proposing to separately state the Utilities Receipts Tax on customer bills instead of including it in the calculation of the factors in this Rider. This is further discussed by NIPSCO Witnesses Shikany and McCuen. The production and energy

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[33] NIPSCO currently estimates that 19,000 LED street light installations will be completed on or after January 1, 2020.

[34] In Riders 883, 886, 887 and 888, NIPSCO is proposing to separately state the Utilities Receipts Tax on customer bills instead of including it in the calculation of the factors.

allocators utilized for purposes of allocating the costs inside of this Rider will be updated based upon the Allocated Cost of Service Study. The RA Adjustment Factors are shown in Appendix F.

Rider 876 – Back-Up and Maintenance Industrial Service Rider (BMIS)

This Rider is only available to Customers taking service under Rate 831 who desire to take service subject to Curtailments from the Company for Back-up or Maintenance purposes. Nothing in this Rider excuses the Customer from its Rate 831 Tier 2 and Tier 3 Curtailment obligations or the penalties associated with failing to meet those obligations. Back-up and Maintenance Services under this Rider shall be subject to Curtailments when Curtailment under Rate 831 is insufficient. Energy under this Rider shall be subject to other Riders as identified on Appendix A. Customers taking service under this Rider shall operate their cogeneration facilities to meet their demand in excess of the sum of their Rate 831 Tier 1, Tier 2 and Tier 3 Contract Demands except when their cogeneration facilities are experiencing a forced outage or derate, or when the Customer is taking confirmed Maintenance Service under this Rider. This is further discussed by NIPSCO Witness Campbell. A contract is required for Back-up Service under this Rider. The billing rates have been updated.

Rider 881 – Demand Response Resource Type 1 (DRR-1) – Energy Only (DRR 1)

Rider 881 is available to Customers taking service under Rates 823, 824, 825, 826, 830, or 831 who have sustained ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 831 and registered as a Load Modifying Resource; unless MISO rules change and do not permit load used by the Company as a Load Modifying Resource to also participate as a Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rate 830 or 831. The Customer shall enter into a written contract with the Company to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with the Company acting as the Market Participant for the Customer. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rate 830 and Rate 831. NIPSCO also has removed the Marginal Forgone Retail Rate (“MFRR”) provisions within the Rider to better align with MISO’s treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by NIPSCO Witness Campbell.

Rider 882 – Emergency Demand Response Resource (EDR) – Energy Only (EDR-1)

Rider 882 is available to Customers taking service under Rates 823, 824, 825, 826, 830, or 831 who have a sustained ability to reduce energy requirements through indirect participation in MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 831 and registered as a Load Modifying Resource; unless MISO rules change and do not permit load used by the Company as a Load Modifying Resource to also participate as an Emergency Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rate 830 or 831. The Customer shall enter into a written contract with the Company to reduce a portion of its electric load for single or multiple Interval

Data Recorder meters through participation with the Company acting as the Market Participant for the Customer. Customers who do not qualify as a Load Modifying Resource may, however, participate as an EDR with any load. Customers taking service under this Rider shall not take power under the temporary, surplus power, back-up and maintenance services during an event under this Rider. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rate 830 and Rate 831. NIPSCO also has removed the Marginal Forgone Retail Rate ("MFRR") provisions within the Rider to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by NIPSCO Witness Campbell.

Mr. Westerhausen stated the majority of changes in the Proposed Rules relate to the addition of definitions that are needed relating to the addition of Rate 831.

Mr. Westerhausen sponsored NIPSCO's proposed standard electric contract for service as Attachment 19-B. He noted the agreement has been revised to (1) update the applicable rates, (2) incorporate information required under Rate 831, (3) remove information previously required under Rider 775, (4) include Rate 830 under Back-Up Service, and (5) add a notice and correspondence information.

Mr. Westerhausen sponsored a summary of billing determinants for the Historic Base Period, 2018 Budget Period and Forward Test Year as Attachment 19-C. He stated the 2019 adjusted projected billing determinants were utilized for the development of the proposed rate design in this proceeding.

Mr. Westerhausen also presented a detailed description of the three sets of customer migrations for this case: 2017 Large Customers, 2019 large Customers, and 2019 Small Customers and explained how these customers were migrated. Mr. Westerhausen described and supported the following proposed pro forma adjustments:

- Adjustment Rev 1A-17 and FP 1A-17 on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to increase test year operating revenue levels by $5,966,365 to reflect a normalized level of revenue at NIPSCO's tariff rates.

- Adjustment Rev 1B-17 on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $44,239,220 to normalize 2017 revenues for the TCJA.

- Adjustment Rev 1D-17 and FP 1B-17 on Petitioner's Exhibit No. 4, Attachment 3-C-S2, REV 1. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $352,249 for large customer rate migration in order to match migrations included in the budget for the twelve months ending December 31, 2018 and 2019.

- Adjustment Rev 1A-19R and FP 1A-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $933,450 to normalize weather by converting the budget weather normal definition for CDD and HDD of 35-years ended 2010 to the regulatory 30-years ended 2017 definition for CDD and HDD, which is consistent with past ratemaking practice.

- Adjustment Rev 1C-19R and FP 1C-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $45,845,611 to update the pricing model utilized in the budget process. When NIPSCO modeled the anticipated change in industrial customer usage described in Adjustments Rev 1D-19R and Rev 1A-19SS, NIPSCO updated the PROMOD inputs utilized to determine the volumes generated at each station. This resulted in changes in revenues, fuel costs, fuel handling expense, variable chemicals, and coal inventory. If this adjustment is not included, Forward Test Year electric operating revenues would be overstated. A corresponding adjustment was to decrease Forward Test Year fuel and purchased power expense in the amount of $45,845,611 in Adjustment FP 1C-19R.

- Adjustment Rev 1D-19R and FP 1D-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $76,792,660 related to the migration and annualization of large industrial customers. If this adjustment is not included, Forward Test Year electric operating revenues would be overstated. A related adjustment was made to decrease Forward Test Year fuel and purchased power expense in the amount of $31,507,991in Adjustment FP 1D-19R.

- Adjustment Rev 1F-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to increase Forward Test Year electric operating revenues in the amount of $4,507,281 to reflect the discount passed through to retail electric customers taking service under the Company's EDR.

- Adjustment Rev 1G-19R and FP 1F-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $1,488,190 to reflect an anticipated decrease in street lighting billing determinants because the budget did not anticipate the increase in customer participation under the LED street lights resulting in less usage.

- Adjustment Rev 1A-19SS and FP 1A-19SS on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $83,630,802 to reflect changes in industrial fuel based on the proposed new service structure.

- Adjustment Rev 1B-19SS on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $3,000,000 to remove all Rate 732 and 733 back-up and maintenance revenues based on the proposed new service structure which gives Rate 831 customers alternatives for Back up and Maintenance Services. Any Back up and Maintenance margins generated by Rider 876 and within Rate 830 will be passed back in the RTO tracker.

- Adjustment Rev 7-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 7. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $10,822,388 for DSM lost revenues that will continue to be recovered through NIPSCO's DSM tracker filing after "Step 1" base rates are implemented.

Mr. Westerhausen explained the proposed increase in the Trip Charge. He explained that NIPSCO is proposing to increase the revenue collected in the Forward Test Year by $18,780. If a Customer schedules an appointment in association with a service request, and the Company's serviceman is not able to gain access to the Customer's facilities due to the absence of the Customer, the Customer shall be charged a Trip Charge at the time the appointment is rescheduled by the Customer. NIPSCO is proposing a $15 increase in this charge, raising it from $40 to $55. In the Historic Base Period, there were 1,252 trips made. Applying this same number of trips to the Forward Test Year, multiplied by the $15 increase in the Trip Charge results in an $18,780 increase.

Mr. Westerhausen explained the proposed increase in the Reconnection Charge. He explained that NIPSCO is proposing to increase the revenue collected in the Forward Test Year by $164,280. A Customer incurs a Reconnection Charge whenever the service has been turned off by the Company in accordance with Rule 12 (shut off for non-payment). NIPSCO is proposing a $20 increase in the charge for normal working hours, raising it from $70 to $90. In the Historic Base Period, 8,214 disconnect/reconnect trips were made. Applying this same number of trips to the Forward Test Year, multiplied by the $20 increase in the Reconnection Charge results in a $164,280 increase.

Mr. Westerhausen described how the Rate 830 Billing Determinants were derived. He explained that customers taking service on the proposed Rate 830 are coming from both Rates 732 and 733. The starting point for the Rate 830 demands, energy and reactive kilovolt Amps is the 2019 forecast. Proposed Rate 830 has different contract requirements than the current Rates 732 and 733. The 2019 demand forecast is based on the current rates and ratchets. NIPSCO reviewed the 12 months ending September 2018 demand billing components and recalculated these billing demands based on the customer's on-peak and off-peak demands and eliminated any influents of current contract demands. The forecasted billing demands were reduced to these recalculated billing demands.

Mr. Westerhausen described how the Rate 831 Billing Determinants were derived. He explained that customers taking service on the proposed Rate 831 are coming from Rates 732, 733 and 734. The starting point for the Rate 831 demands, energy and reactive kilovolt Amps is the 2019 forecast. Proposed Rate 831 has three tiers of service as described above and allows customers with multiple premises to aggregate their load on an hourly basis. The customers can select a Tier 1 contract demand which when multiplied by 12 becomes their annual billing demand. NIPSCO took the customers 2017 actual hourly demands, aggregated them for the two customers where aggregation applies and then calculated the hourly Tier 1 and Tier 2 and 3 energy. These were them summed to calculate the customer's annual 2017 energy for Tier 1 and Tiers 2 and 3. The 2017 energy was compared to the 2019 forecast energy. For customers with a Tier 1 energy with a 99% or higher load factor, the Tier 2 and 3 energy was adjusted. For the customer that has a Tier 1 load factor below the 99%, the adjustment was made at the same proportion as their 2017 Tier 1 and Tier 2 and Tier 3 energy. Transmission flow studies were performed for two customers who have multiple Premises held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1) and having the same qualifying service voltage, IDR meters with 5-minute interval telemetry capability at those Premises. Transmission volumes were calculated for the gross energy consumption (not netted with potential outputs from other qualifying meters) of each individual IDR meter. Their Tier 2 and 3 energy was adjusted based on these studies. There were no adjustments made to the forecasted reactive kilovolt Amps.

Mr. Westerhausen described NIPSCO's proposed updates to the tracker allocators in this proceeding. He explained that Rate 831 contains three tiers of service with the current trackers applicable to the Tier 1 firm service. The energy only revenue requirement of the RTO would also apply to Tier 2. Currently, it is assumed that no transmission-related costs will remain in the FMCA, but if that changes in the future transmission-related charges would apply to both the Tier 2 and Tier 3 transmission portion of Rate 831. The demand allocators are based on the mitigated allocation of the Allocated Cost of Service Study revenue. The Rate 831 allocation was adjusted to reduce the Allocated Cost of Service Study revenue down to the revenue associated with Tier 1. The energy allocators are based on the sales allocator from the Allocated Cost of Service Study. The Rate 831 sales are strictly the Tier 1 sales so no adjustment is required. Rate 831 Tier 2 transmission volumes are not known at this time, so a placeholder has been included in the allocation. The TDSIC transmission allocators are based on the transmission and subtransmission allocation of the revenues in the Allocated Cost of Service Study. Rate 831 has been adjusted to the transmission volumes for Tier 1. The TDSIC distribution allocators are derived from the primary and secondary distribution revenue from the Allocated Cost of Service Study. No adjustments were made for Rate 831. The tracker allocations are provided in Attachment 19-F.

7. <u>OUCC's and Intervenor's Responsive Cases-in-Chief</u>.

a. <u>OUCC</u>.

[LaPorte County defers to the OUCC's summary of its case-in-chief testimony].

b. <u>NIPSCO Industrial Group</u>.

[LaPorte County defers to any summary, edits or revisions submitted by the NIPSCO Industrial Group].

c. <u>U.S. Steel.</u>

[LaPorte County defers to any summary, edits or revisions submitted by U.S. Steel].

d. <u>Walmart.</u>

[LaPorte County defers to any summary, edits or revisions submitted by Walmart].

e. <u>CAC</u>.

[LaPorte County defers to any summary, edits or revisions submitted by CAC].

f. <u>IMUG.</u>

[LaPorte County defers to any summary, edits or revisions submitted by IMUG].

g. <u>NLMK's.</u>

[LaPorte County defers to any summary, edits or revisions submitted by NLMK].

8. <u>NIPSCO's Rebuttal Testimony.</u>

[LaPorte County defers to any summary, edits or revisions submitted by NIPSCO of its rebuttal].

9. <u>Cross-Answering Testimony and Evidence.</u>

a. <u>CAC</u>

[LaPorte County defers to any summary, edits or revisions submitted by CAC].

b. <u>ICC</u>

[LaPorte County defers to any summary, edits or revisions submitted by ICC].

c. <u>ICARE</u>

[LaPorte County defers to any summary, edits or revisions submitted by ICARE].

d. Sierra Club

[LaPorte County defers to any summary, edits or revisions submitted by Sierra Club].

e. NLMK

[LaPorte County defers to any summary, edits or revisions submitted by NLMK].

f. Industrial Group

[LaPorte County defers to any summary, edits or revisions submitted by the Industrial Group].

10. Overview of the Revenue Requirement Settlement.

[LaPorte County takes no position and has intentionally not submitted any further proposed order or briefing language and defers to the arguments, proposed language, or positions presented by other parties in this matter].

11. Testimony in Support of the Revenue Requirement Settlement.

a. NIPSCO

[LaPorte County defers to any summary, edits or revisions submitted by NIPSCO].

b. OUCC

[LaPorte County defers to any summary, edits or revisions submitted by the Industrial Group].

c. Industrial Group

[LaPorte County defers to any summary, edits or revisions submitted by the Industrial Group].

d. Sierra Club

[LaPorte County defers to any summary, edits or revisions submitted by the Sierra Club].

12. Testimony in Response to the Revenue Requirement Settlement.

a. ICC

[LaPorte County defers to any summary, edits or revisions submitted by the ICC].

b. ICARE

[LaPorte County defers to any summary, edits or revisions submitted by ICARE].

c. **LaPorte's Settlement Reply Testimony**. Reed W. Cearley, a special utility consultant, filed limited testimony on behalf of LaPorte County in response to the settling parties' Revenue Settlement. Mr. Cearley's testimony focused primarily on the proposed rate of return under the Settlement. He noted that the although the Settlement proposes a return on equity level less than what NIPSCO's witnesses recommended, the Settlement ROE figure is still well above the levels identified by both the OUCC and Intervenor witnesses and he therefore took issue with the proposed 9.90% ROE settlement figure. Mr. Cearley testified that this opposition was based, in part, on the continuing below average customer satisfaction results

NIPSCO continues to accrue. Mr. Cearley pointed to NIPSCO's J.D. Power rankings for both residential and business customers for the years 2016 through 2018, which were summarized in and provided as attachments to his testimony. Mr. Cearley noted that while NIPSCO's score compared to its own previous years have improved, when compared to its peers, he observed that NIPSCO continued to score below the average utility satisfaction scores. Mr. Cearley noted that NIPSCO has recognized the value of the JD Power survey results and as noted in its direct case NIPSCO identified customer service as one of its top core objectives. Accordingly, Mr. Cearley did recommend that customer satisfaction should continue to be a part of the Commission's consideration in determining an appropriate overall return on equity consistent with the Commission's reasoning and determination in NIPSCO's last fully contested rate proceeding in Cause No. 43526. In this instant case, Mr. Cearley set forth the ROE ranges proposed by the other witnesses in the case and recommended the return ultimately granted factor in and consider NIPSCO's customer satisfaction survey results and certain risk factors that are being mitigated in this case.

On July 16, 2019 the Commission issued a docket entry ("July 16 Docket Entry") seeking additional information relating to Mr. Cearley's June 7, 2019 testimony. In that July 16 Docket Entry the Presiding Officers pointed to Mr. Cearley's testimony suggesting risk adjustments be made to the proposed Settlement ROE to address the effect of mitigating NIPSCO's risks for environmental and its large industrial load. In its July 17, 2019 Response, LaPorte County provided both recommended ROE adjustments and the background and basis of support for the Mr. Cearley's risk factor mitigation recommendations presented in the response.

13. Revenue Requirement Settlement Reply Testimony

a. NIPSCO

[LaPorte County defers to any summary, edits or revisions submitted by NIPSCO].

14. Overview of the Rate 831 Settlement.

[LaPorte County takes no position and has intentionally not submitted any further proposed order or briefing language and defers to the arguments, proposed language, or positions presented by other parties in this matter].

15. Testimony in Support of the Rate 831 Settlement.

a. NIPSCO

[LaPorte County defers to any summary, edits or revisions submitted by NIPSCO].

b. Industrial Group

[LaPorte County defers to any summary, edits or revisions submitted by the Industrial Group].

c. U.S. Steel

[LaPorte County defers to any summary, edits or revisions submitted by U.S. Steel].

16. Testimony in Response to the Rate 831 Settlement.

a. OUCC

[LaPorte County defers to any summary, edits or revisions submitted by the OUCC].

b. CAC

[LaPorte County defers to any summary, edits or revisions submitted by the CAC].

c. Walmart - joined in the CAC's responsive testimony; and

a. Sierra Club joined in the OUCC's responsive testimony.

17. Rate 831 Settlement Reply Testimony

a. NIPSCO

[LaPorte County defers to any summary, edits or revisions submitted by NIPSCO].

18. 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). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (*quoting Citizens Action Coalition v. PSI Energy, Inc*., 664 N.E.2d 401, 406 (Ind. Ct. App. 1996). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action 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 (*quoting Citizens Action Coalition v. Public Service Co*., 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before this Commission can approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such Settlement serves the public interest.

At the same time, Indiana law strongly favors settlement as a means of resolving contested proceedings. *See, e.g., Manns v. State Dept. of Highways*, 541 N.E.2d 929, 932 (Ind. 1989); *Klebes v. Forest Lake Corp*., 607 N.E.2d 978, 982 (Ind. Ct. App. 1993); *Harding v. State*, 603 N.E.2d 176, 179 (Ind. Ct. App. 1992). A settlement agreement "may be adopted as a resolution *on the merits* if [the Commission] makes an independent finding supported by 'substantial evidence on the record as a whole' that the proposal will establish 'just and reasonable' rates." *Mobil Oil Corp. v. FPC*, 417 U.S. 283, 314 (1974) (emphasis in original). *See also, Indianapolis Power & Light Co*., Cause No. 39938, p. 7 (IURC 8/24/95); *Commission Investigation of Northern Indiana Public Service Co*., Cause No. 41476, p. 23 (IURC 9/23/02). This policy is consistent with expressions to the same effect by the Indiana Supreme Court. *See, e.g., Mendenhall v. Skinner & Broadbent Co*., 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes.") (citation omitted); *In re Assignment of Courtrooms, Judge's Offices and Other Facilities of St. Joseph Superior Court*, 715 N.E.2d 372, 376 (Ind. 1999) ("Without question, state judicial policy strongly favors settlement of disputes over litigation.") (citations omitted). Furthermore, the Commission is mindful regarding a settlement which has been entered into by representatives of all customer classes, including the OUCC (who represents all ratepayers), even though there may be some intervenor or group of intervenors who opposes it. *American Suburban Utils*., Cause No. 41254, pp. 4-5 (IURC 4/14/99).

In this proceeding, our review of the reasonableness of the Settlement is aided by the Settling Parties' express agreement on the rate base, rate of return, operating expenses, pro forma adjustments, allocation factors, and rate designs to be used in determining NIPSCO's retail electric rates and charges. As a result, we have been able to examine the basis for all of the components of the increase in basic rates and charges provided for in the Settlement and can discern how each disputed issue was resolved by the Settling Parties.

A. **Revenue Requirements Settlement**

In this case, the Settling Parties have agreed to an overall annual revenue requirement of $ $1,482,166,740 (prior to application of surviving Riders and net of other revenues), which translates to a decrease of $63.648 million in the amount originally requested by NIPSCO. This agreement on an appropriate revenue requirement for NIPSCO is based upon agreements among the Settling Parties regarding original cost rate base, fair value rate base, capital structure, cost of capital, and operating expenses (including depreciation expense and tax expense). As is discussed in further detail below, we find that the Settlement provisions regarding NIPSCO's revenue requirements are reasonable, supported by evidence of record, and should be approved.

(1) Petitioner's Rate Base. NIPSCO presented evidence, which no party disputes, that its generating properties, transmission system, distribution system, offices and general facilities included in its proposed rate base were all used and useful and reasonably necessary for the convenience of the public and should be included in NIPSCO's retail electric rate base, and we so find.

A first step in determining revenue requirements requires the Commission to value all property used and useful for the convenience of the public at its fair value. Ind. Code §8-1-2-6. NIPSCO, along with the other Settling Parties, has agreed that, for purposes of establishing rates in this case, the original cost of NIPSCO's retail electric rate base should be used, which is $3,221,417,882. This value includes materials, supplies, production fuel inventory and regulatory assets as proposed in NIPSCO's case-in-chief but does not include NIPSCO's prepaid pension asset. This original cost value of NIPSCO's rate base is supported by the Company's initial, rebuttal and settlement testimony. We further note that no party disputes the components or value of this agreed upon original cost rate base. Accordingly, we find that NIPSCO's original cost rate base for purposes of this proceeding is $3,221,417,882, and that this original cost rate base should be used for purposes of determining a fair return on the fair value of NIPSCO's used and useful property for purposes of this case.[35]

(2) Fair Rate of Return. Having determined the fair value of Petitioner's used and useful property, we now turn to a determination of the level of net operating income that represents a reasonable return on that property. We are charged with providing the utility with the opportunity to earn a fair return on the fair value of its property. *See Gary-Hobart Water Corp. v. Ind. Util. Reg. Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App. 1992) and *Office of Util. Consumer Counselor v. Gary-Hobart Water Corp.*, 650 N.E.2d 1201 (Ind. Ct. App. 1995). One accepted way of doing this is to determine NIPSCO's actual capital structure, along with the cost of the various components of its capital, as the Settling Parties have done. The Settling Parties have

[35] As noted, Ind. Code § 8-1-2-6 requires the Commission to value a public utility's used and useful property at its "fair value." Absent settlement of this issue, the original cost determination would not necessarily be an accurate reflection of the true "fair value" of NIPSCO's property. However, in the context of settlement and for the purposes of this case, we believe it is reasonable to conclude that "original cost" also constitutes an accurate reflection of the "fair value" of NIPSCO's utility property for purposes of Ind. Code § 8-1-2-6.

agreed that the following actual capital structure and cost of capital for NIPSCO should be used in setting rates in this case:

	Dollars	Cost %	WACC %
Common Equity	$2,864,884,714	9.90	4.74
Long-Term Debt	$2,151,351,378	4.97	1.79
Customer Deposits	$71,453,491	4.91	0.06
Deferred Income Taxes	$1,266,429,454	0.00	0.00
Prepaid Pension Asset	$66,142,914	0.00	0.00
Post-Retirement Liability	$(435,272,223)	0.00	0.00
Post-1970 ITC	$2,014,831	8.30	0.00
Totals	**$5,987,004,559**		**6.59%**

The evidence of record indicates that this agreed upon capital structure represents the actual capital structure of NIPSCO, including equity, long-term debt, customer deposits, deferred income taxes, the prepaid pension asset, the OPEB liability, and post-1970 investment tax credits. No party disputes that the above capital structure represents the actual capital structure of NIPSCO.

It is further undisputed that NIPSCO's evidence demonstrated that its embedded cost of long-term debt was 4.97%, its cost of customer deposits was 4.91%, and that deferred income taxes, the prepaid pension asset, the OPEB liability, and post-1970 investment tax credits should be treated as zero-cost capital.

With regard to NIPSCO's cost of equity, the record contains testimony from multiple witnesses who provide recognized methods of estimating NIPSCO's cost of equity but with differing recommendations. We recognize that the cost of equity cannot be precisely calculated and estimating it requires the use of judgment and the consideration of more than one methodology. The testimony of various witnesses in this case reflected initial views that NIPSCO's cost of equity was between 8.75% to 10.8%, with the Settling Parties concluding that 9.90% was a reasonable cost of equity to use to set rates in this case.

We have also been presented with testimony and evidence in this matter related to customer service feedback and survey considerations. We are mindful of our Final Order in NIPSCO's last non-settled rate proceeding in Cause No. 43526, wherein we found and determined on that:

> Further, in Cause No. 42359, we determined that PSI's reliability and quality customer service warranted some consideration in our ultimate cost of equity determination. The evidence showed that PSI, and its parent Cinergy Corp., scored in the top quartile of the most recent J.D. Power and Associates customer satisfaction studies. In contrast, the evidence presented in this Cause demonstrated that NIPSCO was in the bottom quartile of the J.D. Power studies in 2007 and 2008, and one of the worst-rated utilities in 2009. While we are hesitant to place undue

weight on customer surveys, the three-year trend of poor customer satisfaction cannot be ignored.

(IURC 8/25/10 Order in Cause No. 43526, at 32).

We see that in the instant case NIPSCO's Witness Sistovaris raised and discussed the importance of customer service and customer feedback in her direct testimony. She stated that NIPSCO is constantly monitoring service and reliability metrics and indicated that providing top-tier service will continue to be a priority for NIPSCO. She explained that NIPSCO is working every day to improve its customer service delivery. We are encouraged that NIPSCO has both recognized the need for and incorporated direct customer feedback into its day-to-day management operations and made this a priority. Further in her reply testimony Ms. Sistovaris notes that NIPSCO's J.D. Power scores have been improving and that NIPSCO has been improving relative to its peers and NIPSCO is moving closer to the average survey result. We recognize these improvements and encourage NIPSCO to continue to make customer feedback and input a priority for NIPSCO.

Giving due consideration of this evidence of record, including the Settlement and the risks and challenges facing electric utilities generally and NIPSCO in particular, we find that the agreed upon cost of equity of 9.90% is within a reasonable range of the evidence presented. We also find that use of a 9.90% cost of equity to set rates for NIPSCO is supported by the risks facing NIPSCO in particular and the electric utility industry generally and is supported by the evidence demonstrating NIPSCO's reliability and customer service performance. Accordingly, we find that a 9.90% cost of equity, along with the other cost of capital components shown above, producing an overall weighted cost of capital of 6.59% for NIPSCO, is reasonable in this case. Further, the evidence of record indicates that this overall weighted cost of capital, when applied to Petitioner's rate base, produces a net operating income of $271,211,585. Accordingly, we also find that, for purposes of the earnings test contained in the FAC statute, NIPSCO shall be authorized to earn this net operating income of $271,211,585, prior to any additional returns approved by the Commission in future capital cost tracking proceedings.

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[LaPorte County takes no position and has intentionally not submitted any further proposed order or briefing language and defers to the arguments, proposed language, or positions presented by other parties in this matter].

***

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

1. The Revenue Requirement Stipulation and Settlement Agreement between NIPSCO, Industrial Group, NLMK Indiana, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC filed in this Cause on April 26, 2019, and attached hereto, shall be and hereby is approved and accepted, and adopted by the Commission, in its entirety, without change or modification.

2. ***

3. ***

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

HUST0N, FREEMAN, KREVDA, OBER, AND ZlEGNER CONCUR:

APPROVED:

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

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**Mary M. Becerra,
Secretary to the Commission**